Renewable Gas Blending Scheme

prepared for:
Energy Networks Australia

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Executive Summary

Australia is currently preparing a National Hydrogen Strategy. That strategy is to consider a target for blending hydrogen with natural gas - of which methane (CH4) is the primary constituent - into Australia's gas networks.

Adding moderate amounts of hydrogen to a natural gas network would appear to be technically feasible, with the materials used in modern gas networks being compatible with hydrogen and with many current appliances already tested at up to a 13% hydrogen (by volume) blend. There are few other material technical barriers to the physical injection and transportation of moderate amounts of hydrogen within Australia's existing natural gas distribution networks, although locational production will be key. Moreover, based on other work commissioned by Energy Networks Australia, there appears to be no major legal impediments to the injection of moderate amounts of hydrogen into networks.

Notwithstanding this, it is our understanding that there are very few recent examples of hydrogen being blended into existing natural gas networks at moderate levels across the world. This stems from the fact that the underlying costs of hydrogen are higher than the cost of natural gas. Whilst the primary technologies used to produce hydrogen are mature (e.g. electrolysis) and have not changed significantly in recent times, the costs of, and emissions stemming from, the electricity used to power the process have changed significantly, and are expected to decline further in the future.

If hydrogen can be economically produced from low-carbon energy sources such as solar or wind (or steam methane reforming of natural gas paired with carbon capture and storage), then blending it into existing natural gas networks could potentially lead to a significant reduction in greenhouse gas emissions, a more diversified energy supply industry, as well as more competition in the gas market and lower overall costs for consumers in the long-run. It could also be a precursor to the development of other renewable gases such as renewable methane, which would be a direct replacement for fossil fuel based methane/natural gas/LNG, as well as a plethora of other potential products that can be made from or powered by hydrogen (e.g., renewable gasoline, use in gas fired generation equipment).

That said, whilst Australian gas (and complementary electricity) markets feature a myriad of price signals – from wholesale price signals, to network price signals through to retail price signals - most economists would agree that not all of the price signals currently in the market are efficient. Additionally, Government-sponsored subsidies that are applied to specific sectors of the energy market can further distort the energy market (and other complementary sectors) in unintended ways. So, whilst the production costs of renewable gases appear to have improved significantly, the absence of efficient price signals across both the gas and electricity sectors may, *in theory*, place the efficient take-up of renewable gases at risk, which is not in the long-term interests of consumers.

In this context, we have been asked by Energy Networks Australia to assist them with developing a Renewable Gas Blending Scheme. The overarching objective of such a Scheme would be to:

- Incentivise the injection of renewable gas into Australia's natural gas networks at a *sufficient scale* in order to unlock a number of long-term benefits to consumers;
- Facilitate the achievement of the blending target at the *least cost* to the community; and
- Be designed in a way that *constrains* the financial impact on customers to levels that most customers are unlikely to notice or be unduly affected by, and which limits the distributional impacts of the scheme.

In considering the design of the Scheme, it is our opinion that:

- The focus of the Scheme should relate to all types of renewable gases, as opposed to one particular renewable gas (e.g., hydrogen). We believe that by opening up a Scheme to more competition (e.g., more renewable gases), the Scheme is more likely to deliver outcomes that are in the long-term interests of consumers; and
- Whilst there are numerous ways in which renewable gases can be used – for example, in transport (via fuel cell technology), industrial processes or for export (via liquification) - the focus of the Scheme should relate purely to the blending of renewable gases into natural gas systems across Australia.

We consider that there are a number of potential design options, including:

- A certificate-style scheme (akin to the Renewable Energy Target (RET));
- A feed-in tariff (FiT) scheme;
- Distribution businesses purchasing their Unaccounted for Gas (UAFG) requirements from renewable gas sources;
- A reverse auction scheme to procure renewable gases; and
- Relying on the existing Climate Solutions Fund.

Whilst each of the above approaches has certain advantages and disadvantages, on balance, we believe that a certificate-style scheme is conceptually, likely to be the most appropriate means of incentivising the blending of renewable gas into Australia's gas networks. In coming to this conclusion, we have placed significant weight on the fact that a certificate-style scheme:

- If designed correctly, decouples the production of renewable gas from the location where the liability is generated; hence, everything else being equal (e.g., transportation costs), incentivising the production of renewable gas to be located where it is cheapest to produce;
- Generates certificate prices, and hence costs, that reflect underlying market fundamentals, which overcomes the inherent issue with a FiT arrangement that relies on a centrally administered, *ex ante* rate being set (with all the associated risks that stem from that); and
- Mimics the existing RET scheme, hence the existing suite of governance and institutional arrangements should be able to be utilised (or require minimal change to be used).

The key features of the certificate-style Scheme that we have conceptualised are outlined below:

- Which category of businesses should be liable for surrendering certificates?
  - The Scheme would be applied to Licenced Gas Retailers (of a certain size threshold) operating in the various Australian States.
  - If it is not possible to get a retailer-liable scheme implemented in the near term, then we would recommend that the liability be placed on "covered" (or 'Scheme') "distribution" pipelines in the short-term.
- On what basis should each entity's liability be determined in a year?

- A retailer's liability should be based on their total gas sales[1] in a previous year to customers in qualifying distribution regions, multiplied by the target blending rate for the year in question. This would give a GJ target for a target year, which would then need to be converted **to a volume target** based on the relative energy per cubic metre of natural gas v hydrogen or other renewable gas.

- What types of gases should be eligible for certificates?
  - Only 100% renewable gases be eligible for certificate creation, although the Scheme could easily be extended to incorporate non-renewable, but very low-emission forms of hydrogen such as SMR with CCS, if policymakers considered this to be in the long-term interests of consumers;
  - We would recommend that no sub-targets be set for different technologies (e.g., renewable hydrogen versus renewable methane).
- On what basis should the target/s be set?
  - We would recommend that a National, rather than a State-based or distribution-business specific, target be set so as to decouple the production of renewable gas from the location where the liability is generated, in turn enabling renewable gas producers to seek out appropriate levels of scale efficiency and to locate in areas that have the cheapest cost of production (everything else being equal).
- What facilities should be eligible for certificate generation?
  - We would recommend that (a) both existing and new facilities be eligible to create certificates; subject to (b) those facilities injecting a certified gas into certain types of pipelines (see below).
  - Our initial thinking is that eligible gases must be injected into a pipeline that is, or has been, subject to a **form of regulation**[2] under the National Gas Law (NGL) or the National Third Party Access Code for Natural Gas Pipelines (the previous scheme). A list of such pipelines is contained on the AEMC's website[3]. This would of course be subject to the technical capabilities of individual pipelines to safely cater for any injections.
- At what percentage level should the final target be set, and how long should the scheme run for?
  - We would recommend that the Scheme operate for a minimum 15 years, reflecting the reasonably long-lived nature of assets required to provide renewable gases. This duration should also facilitate the 'bankability' of the Scheme in the eyes of investors.

1 If the distribution business is the liable entity in the early stages of the Scheme, the number of certificates that they would be liable to surrender would simply be based on the volumes they deliver.

2 This should not to be confused with the concept of a "covered" pipeline. Pipelines that have been subject to some form of regulation under the NGL could in fact be a covered or an uncovered pipeline. It is our understanding that there are around 130 of these pipelines in Australia.

3 https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register

- Given the assumption that many current appliances have already been tested at up to a 13% hydrogen (by volume) blend, and assuming (conservatively) that there will be minimal blending outside of Australia's 'covered' gas distribution networks, a target in the order of 10% of volume[4] would appear to represent (a) a 'material' target, whilst also (b) providing reasonable flexibility to decouple the production of renewable gas from the location where the liability is generated.

- How should customers be protected in terms of the bill impacts?
  - We think an explicit volume blending target should only be set for the early years of the Scheme's life (e.g., 0.5%, 3%), with a final year rigid target range also being set (e.g., in the order of 10%). Both provide the underlying certainty to investors about the Scheme's overall levels.
  - However, intervening targets could be set 2 years in advance. This lead time is suggested as it reflects a broad estimate of the lead time required to develop a project. There would need to be rigid rules around how these intervening targets would be set so as to give investors enough certainty to support their long-term business models, whilst providing policymakers with some flexibility to manage customer impacts. The rules could include, for example:
    - Specifying minimum incremental increases in the target (i.e., the target must increase by a certain percentage); with
    - Any increment above the minimum level to only be approved if it is forecast to not exceed a pre-specified cap on bill increases (e.g., the Scheme must not add more than 1% per annum to the average residential customer's expected bill). The methodology to determine this would need to be set out in advance, but it would be likely to reference expected future renewable gas production costs and hence certificate prices, which in turn flow through to bill impacts. Furthermore, the Clean Energy Regulator could be charged with periodically publishing forecasts of future intervening targets.
- Who should administer and ensure compliance under the Scheme?
  - The Clean Energy Regulator (CER) should regulate and oversee the Scheme.
- What would the role of pipelines under the Scheme?
  - Pipeliners would continue to operate their systems in a way that allows them to meet all technical, environmental and safety standards etc.
  - To this end, they would have full carriage for ensuring that actual blending rates did not exceed technical limitations, which presumably would be managed through things like connection agreements with the renewable gas producers who are connected to their network.
  - There may be merit in expanding the information that pipeliners periodically publish to the market, so as to provide guidance to existing and prospective renewable gas producers regarding outturn and forecast blending rates, areas where injections may be constrained, connection charging arrangements, etc

4 It should also be noted that for renewable forms of methane (biogas, renewable methane) the volume target would offer some 3 times the energy target for these schemes, potentially providing other scale incentives.

1. Background

Australia is currently preparing a National Hydrogen Strategy. That strategy is to consider a target for blending hydrogen with natural gas - of which methane (CH_4) is the primary constituent - into Australia's gas networks.

Adding moderate amounts of hydrogen to a natural gas network would appear to be technically feasible, with the materials used in modern gas networks being compatible with hydrogen and with many current appliances already tested at up to a 13% hydrogen (by volume) blend[5]. There are few other material technical barriers to the physical injection and transportation of moderate amounts of hydrogen within Australia's existing natural gas distribution networks, although locational production will be key. Moreover, based on other work commissioned by the Energy Networks Australia (ENA), there appears to be no major legal impediments to the injection of moderate amounts of hydrogen into networks[6].

Notwithstanding this, it is our understanding that there are very few recent[7] examples of hydrogen being blended into existing natural gas networks at moderate levels across the world. This stems from the fact that the underlying costs of hydrogen are higher than the cost of natural gas. Whilst the primary technologies used to produce hydrogen are mature (e.g. electrolysis) and have not changed significantly in recent times[8], the costs of, and emissions stemming from, the electricity used to power the process have changed significantly, and are expected to decline further in the future.

If hydrogen can be economically produced from low-carbon energy sources such as solar or wind (or coal gasification paired with carbon capture and storage), then blending it into existing natural gas networks could potentially lead to a significant reduction in greenhouse gas emissions, as well as more competition in the gas market and lower overall costs for consumers in the long-run. It could also be a precursor to the development of other renewable gases such as renewable methane, which would be a direct replacement for fossil fuel based methane/natural gas/LNG, as well as a plethora of other potential products that can be made from or powered by hydrogen (e.g., renewable gasoline, use in gas fired generation equipment).

It is therefore understandable why many stakeholders see the blending of renewable gases such as hydrogen into gas networks as a first step on an exciting pathway of emission reductions, self-reliance for energy, affordable and reliable low emission energy supplies for customers and large export markets. To this end, there have been a number of hydrogen-focused pieces of work that have recently been undertaken both in Australia and overseas:

5 ENA, *Decarbonising Australia's gas networks*, December 2017, page 5

6 This document is available from https://www.energynetworks.com.au/gas-vision-2050.

7 Noting that historically, Towns gas, which consisted of a significant proportion of hydrogen, used to be used in many parts of the world, including Australia.

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

- **National Hydrogen Road Map – CSIRO:** Released in 2018, the objective of this report was to "*provide a blueprint for the development of a hydrogen industry in Australia. With a number of activities already underway, it is designed to help inform the next series of investment amongst various stakeholder groups (e.g. industry, government and research) so that the industry can continue to scale in a coordinated manner*[9]". When explaining why it was focusing on hydrogen, the CSIRO noted that "*clean hydrogen is a versatile energy carrier and feedstock that can enable deep decarbonisation across the energy and industrial sectors*[10]". This report provided detailed estimates of the current and potential future production costs of hydrogen.
- **National Hydrogen Strategy:** In 2018, the Council of Australian Governments (COAG) agreed to commission a national strategy for hydrogen, to be led by Australia's Chief Scientist, Alan Finkel. One of the key recommendations of that strategy was to "*commence work to allow up to 10 per cent hydrogen in the domestic gas network, including the required regulatory changes and implementation of technical standards, in partnership with the Future Fuels CRC*[11]". The National Hydrogen Strategy has been supported by the release of a number of consultation papers, including a Discussion Paper in March 2019 and 9 issues papers in July 2019. These issues papers covered: (a) Hydrogen at scale; (b) Attracting hydrogen investment; (c) Developing a hydrogen export industry; (d) Guarantees of origin; (e) Understanding community concerns for safety and the environment; (f) Hydrogen in the gas network; (g) Hydrogen to support electricity systems; (h) Hydrogen for transport; and (i) Hydrogen for industrial users. A draft National Hydrogen Strategy is due to be released by the end of 2019.
- **Hydrogen blending trials:** A number of Energy Network Australia's members are currently demonstrating the blending of hydrogen into their gas distribution networks. These include:
  - Jemena's 'Power to Gas' trial[12]: Commenced in 2019, this $15 million trial (co-funded by Jemena and ARENA) uses international technology in the form of a 500kW electrolyser to convert solar and wind power into hydrogen gas. This hydrogen gas will then be stored and then blended into Jemena's NSW gas network to power approximately 250 homes.
  - ATCO's "Clean Energy Innovation Hub"[13]: Commenced in 2019, this $3.6m research facility (co-funded by ARENA) will produce around 4 tonnes of hydrogen per year, with this being used as a feedstock for a fuel cell to provide back-up power for houses in a micro-grid precinct, with the rest blended into ATCO's gas distribution system.

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9 https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap

10 CSIRO, *National Hydrogen Roadmap*, 2018, page xiii

11 Australian Government Chief Scientist, *"Proposal for a national hydrogen strategy"*, December 2018, page 1

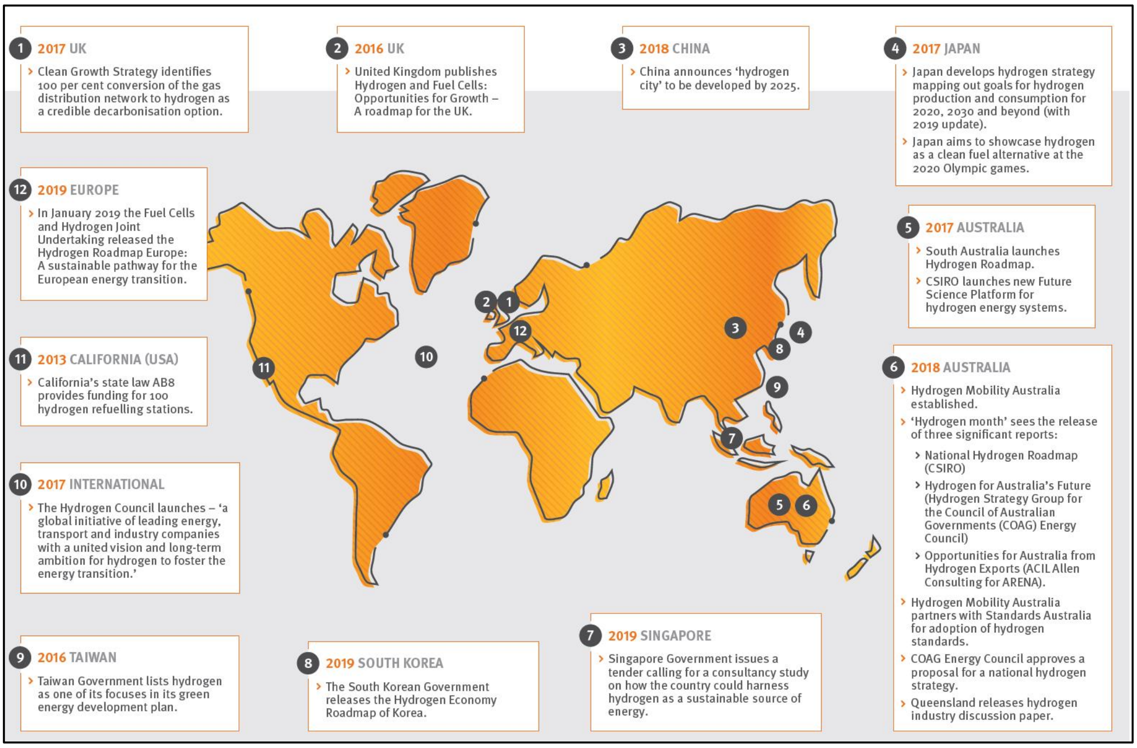
12 https://jemena.com.au/about/innovation/power-to-gas-trial

13 https://www.energynetworks.com.au/sites/default/files/sam_lee_mohan_-_atco_no_video.pdf

- AGIG 'Hydrogen Park SA' in South Australia's Tonsley Innovation District[14]: Commenced in 2018, this $11.4 million power-to-gas demonstration plant – to be called Hydrogen Park SA (HyP SA) – uses a 1.25MW polymer electrolyte membrane (PEM) electrolyser to produce hydrogen from renewable electricity, which will then be blended into the local gas distribution network.

- **Overseas Government Strategies:** There are a number of hydrogen-focused policies being adopted by Government's across the world, a selection of which are contained in the figure below. In addition, it is our understanding that there are a number of blending trials being adopted in other countries, for example:
  - HyDeploy: This will involve a trial of up to a 20% blend of hydrogen and natural gas on part of the private gas network at Keele University's Staffordshire campus[15]
  - Hynet: This will involve the production of hydrogen from natural gas in the north west of England, the development of a new pipeline for industrial users and the blending of up to 20% hydrogen into the existing gas infrastructure[16].

Figure 1: A selection of hydrogen-focused policies announced globally



Source: Department of State Development, Manufacturing, Infrastructure and Planning, *Queensland Hydrogen Industry Strategy 2019-2024*, May 2019, page 5.

14 https://www.australiangasnetworks.com.au/our-business/about-us/media-releases/australian-first-hydrogen-pilot-plant-to-be-built-in-adelaide

15 https://hydeploy.co.uk/

16 http://www.nwhydrogenalliance.co.uk/north_west_section/hydrogen-initiatives/

2. Objective of this report

We have been asked by Energy Networks Australia (ENA) to assist them with developing a Renewable Gas Blending Scheme. This report identifies, amongst other things:

- Renewable gas options,
- What the focus of any Renewable Gas Blending Scheme should be;
- The rationale for implementing a Blending Scheme in particular;
- The foundational issues that need to be considered in the development of any Blending Scheme;
- The advantages and disadvantages of different Blending Scheme design options;
- The Blending Scheme that we would recommend be implemented;
- How the recommended Blending Scheme could be implemented in practice;
- Whether the costs incurred by distribution businesses in facilitating the blending of moderate amounts of renewable gas into their networks under any Blending Scheme would meet the tests outlined in National Gas Rules; and
- The next steps that the ENA should undertake to progress the development of a Blending Scheme.

3. Renewable gas options

There are a number of different types of renewable gases. These include, but are not limited to:

- Hydrogen;
- Biogas; and
- Renewable methane.

The following sub-sections provide an overview of each of these renewable gases.

3.1. Hydrogen

Hydrogen is the most abundant and common element in the universe. At standard temperature and pressure, hydrogen is a colourless, odourless, tasteless, non-toxic and highly combustible gas with the molecular formula H_2. Hydrogen is a clean-burning gas that 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).

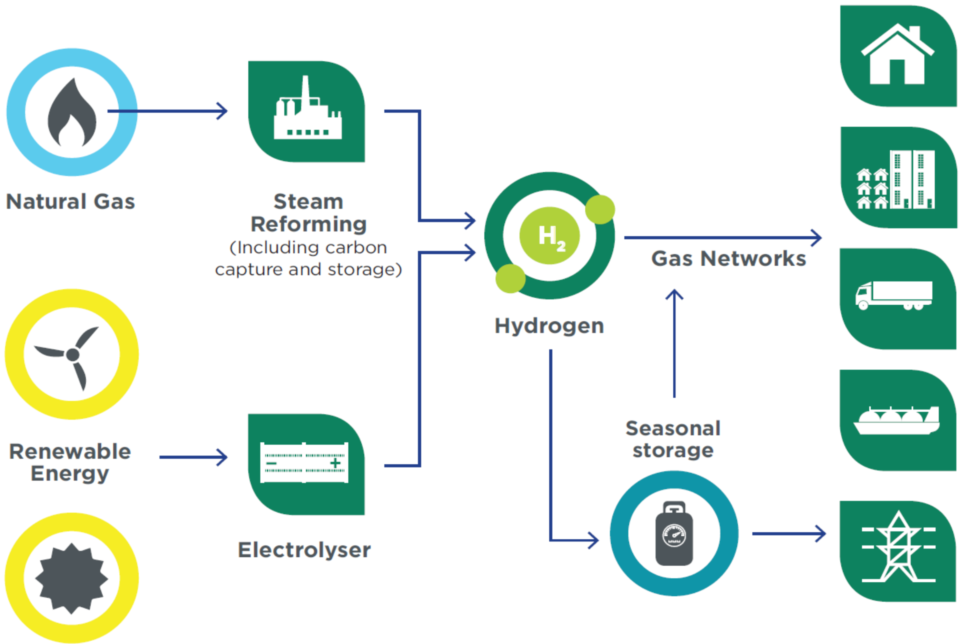
The renewable, zero-emission pathway to creating hydrogen is via electrolysis, using renewable electricity. The two main electrolysis technologies are[17]:

- 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; and
- 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.

Whilst the primary technologies used to undertake this process are mature (e.g. electrolysis) and have not changed significantly in recent times[18], the costs of, and emissions stemming from, the electricity used to power the process have changed significantly. This renewable hydrogen is produced at very high purity (>99.99%) and can be used in many applications, for example fuel cells in vehicles.

SMR is also a mature technology, however, it needs to be combined with carbon capture and storage (CCS)[19] if it is to provide a source of low emissions hydrogen[20]. Even then, it is still not technically “renewable”.

Figure 2: Hydrogen production pathways



Source: ENA, *Gas Vision 2050*, page 4

17 CSIRO, *National Hydrogen Roadmap,* 2018, page 13

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

19 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.

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

Whilst there are very few recent examples of hydrogen being blended into an existing natural gas network at moderate levels anywhere in the world, existing networks and appliances are designed to operate effectively with moderate amounts of hydrogen. However, if the hydrogen content increases, appliance modifications would be required as hydrogen and natural gas behave differently when burnt. Modern gas distribution networks, however, should be able to transport large proportions of hydrogen safely[21].

3.2. Biogas

Biogas is a gaseous form of methane (CH_4), which, as noted earlier, is the primary component of natural gas. 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 are a series of biological processes that are generally used in the sewerage treatment process, or treatment of food waste.

As its production is secondary to a business' main production process (e.g., landfill, sewerage treatment, food production), the potential for it to be utilised in gas networks largely depends on the geographical proximity of the resources to the existing network.

Moreover, whilst it contains mostly bio-methane, it also contains carbon dioxide and water vapour, so it needs to be 'cleaned' before being injected into a natural gas network. There are technologies readily available to do this, however, they add to the cost of production (as compared to using the 'uncleaned' gas to generate electricity).

As the bio-methane that is produced is a direct substitute for natural gas – albeit from a different source in biomass (e.g. food waste) instead of a fossil fuel source - it is fully compatible with natural gas using appliances, networks and gas turbines, so no modifications are required.

It emits net zero CO2e, and is treated as part of the natural carbon cycle under the Australian national greenhouse gas accounting framework. However, most biogas produced in Australia is used to generate electricity, leading to around 7% of Australia's renewable electricity being provided from biogas. This is predominately driven by the Renewable Energy Target (RET), which provides financial incentives for producing renewable electricity (but not renewable gases).

The process is outlined in the figure below.

21 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.

Figure 3: Landfill gas used in renewable electricity production

Source: https://www.greenpower.gov.au [Case Study – "Tipping the Balance"]

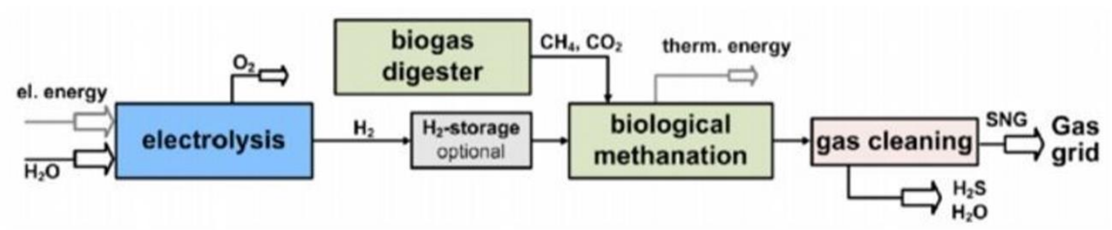
3.3. Renewable methane

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

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 (Figure 5).

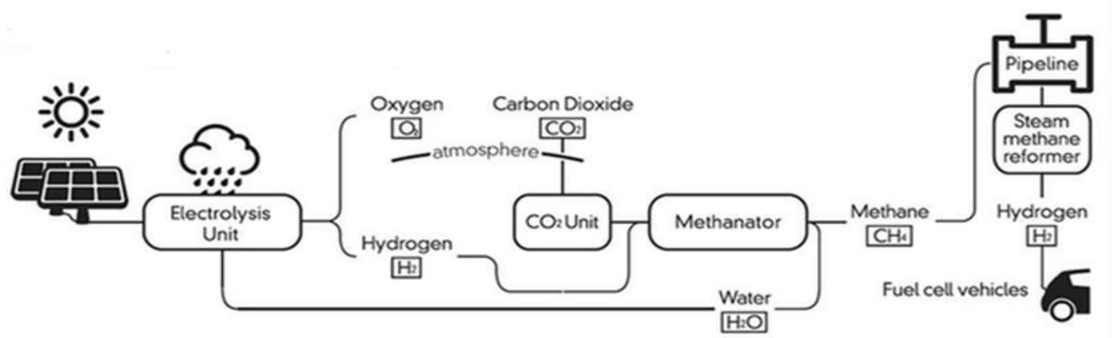
The carbon extracted balances the carbon emitted when the methane is used, therefore making the methane both renewable and carbon neutral.

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 and networks, and hence no additional downstream costs are incurred. In contrast to Hydrogen it also does not see a 60% potential downgrade of the energy carrying capacity of these assets if converted fully to Hydrogen. Renewable methane volume targets are more than 3 times the energy carrying capacity of Hydrogen.

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.

4. Focus of a Renewable Gas Blending Scheme

The following sections discuss:

- The types of gases that should be allowed for under the Scheme; and
- Eligible uses of those gases under the Scheme.

4.1. Types of gases allowed under the Scheme

The focus of the Scheme that is proposed in this report relates to all types of **renewable gases**, as opposed to one particular renewable gas (e.g., hydrogen).

As there is an inherent linkage between hydrogen and the production of some other renewable gases, we believe this is not inconsistent with the National Hydrogen Strategy, which, as stated earlier, is considering a blending target for domestic gas networks. Furthermore, we believe that by opening up a Scheme to more competition (e.g., more renewable gases), the Scheme is more likely to deliver outcomes that are in the long-term interests of consumers. To this end, whilst the Scheme outlined in this report is focused on **renewable gases**, it could be easily extended to incorporate **non-renewable, but low-emission gases** such as hydrogen generated from SMR combined with CCS[22] or potential forms of low emission methane. This would facilitate even more competition under the Scheme.

4.2. Eligible uses of those gases under the Scheme

Whilst there are numerous ways in which renewable gases can be used – for example, in transport (via fuel cell technology), industrial processes or for export (via liquification) - the focus of the Scheme that is outlined in this report relates purely to the blending of renewable gases into natural gas systems across Australia.

Notwithstanding this, any Renewable Gas Blending Scheme (**'Blending Scheme'**) could support and facilitate the achievement of any broader 'Renewable Gas Target' that the Government may wish to set (i.e., one that encompasses things such as the use of hydrogen or renewable methane in transport, or as an export commodity).

22 The adjustments to the Scheme that would be required to facilitate this are discussed in latter sections of this report.

5. Rationale underpinning the implementation of a Blending Scheme

The National Gas Objective (NGO) is[23]:

> *"to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas".*

The NGO is very clearly focused on the long-term interests of consumers. Long-term interests are facilitated by the promotion of economic efficiency[24], and more specifically, productive, allocative and dynamic efficiency[25].

A feature of most efficient markets is that they deliver cost-reflective price signals to the market – that is, price signals that reflect the marginal opportunity costs (to society) of production. Efficient price signals[26] facilitate resources being allocated by the market to their highest value use, which is a fundamental component of economic efficiency.

Whilst the Australian gas (and complementary electricity) markets feature a myriad of price signals – from wholesale price signals, to network price signals through to retail price signals - most economists would agree that not all of the prices currently in the market are efficient. Additionally, Government-sponsored subsidies that are applied to specific sectors of the energy market can further distort the energy market (and other complementary sectors) in unintended ways.

At a general level, many prices are lacking in terms of their ability to signal:

- The increased cost of catering for consumption or export during different times of the day, week, month and year (e.g., periods of network constraint as compared to periods when the network is not constrained);
- The cost of generating or delivering services at different locations (e.g., location-based pricing); and
- The negative externalities associated using different energy generation sources (e.g., gas versus coal).

So, whilst the economics of renewable gases appear to have improved significantly, the absence of efficient price signals across both the gas and electricity sectors may, *in theory*, place the efficient take-up of renewable gases at risk, which is not in the long-term interests of consumers.

There are a number of other related factors that may complement and support the blending of renewable gases into the natural gas system.

The following diagram illustrates the potential benefits of facilitating increased levels of renewable gas being blended into Australian gas networks.

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23 Section 23 of the National Gas Law

24 AEMC, *Applying the energy objectives – A guide for stakeholders*, December 2016, page 1

25 Ibid, page 11 and 12

26 A counterpoint to this is that more centralised processes (e.g., tendering arrangements) can be used to facilitate more efficient outcomes, where there is an absence of efficient price signals. However, at a general level, these processes tend to have much higher transaction costs.

Figure 6: Potential benefits to consumers of a Blending Scheme

The following table provides a very brief description of each potential benefit.

Table 1: Potential benefits to consumers of a Blending Scheme

Benefit to consumers	Description
Counteract the negative impact inefficient price signals have on long-term costs	• Many existing price signals across both the electricity and gas markets lack cost-reflectivity, particularly with regards to the marginal cost of connecting to, transporting and distributing electricity, including electricity that has been exported back into the grid (as well as how their emissions intensity is priced).

	• In particular[27], the application of the RET scheme to renewable electricity sources, but not to renewable gas sources, could lead to inefficient investment decisions. For example, everything else being equal, a biogas proponent is likely to be incentivised to utilise their gas to power an electricity generator as opposed to selling that gas into the gas market, simply because it is able to create renewable energy certificates (REC) if sold into the electricity market (whereas it can't in the gas market, despite it providing similar emissions reduction benefits). Similarly, a new renewable energy generator (e.g., solar, wind) would, everything else being equal, be more inclined to sell into the electricity market in order to create RECs as opposed to utilising that energy directly in other applications (e.g., as a feedstock into the creation renewable gases) that may otherwise not create RECs or a REC equivalent. • Overall, a Renewable Gas Blending Scheme may assist in overcoming some of the inefficient outcomes that could ensue from existing tariffs arrangements and broader schemes affecting the electricity market, and hence could be in the long-term interests of consumers.
Creates increased competition in the gas market	• Creates a platform for the provision of additional products that can be supplied in competition to fossil-fuel based natural gas, potentially reducing any market power that may be able to be exerted by existing natural gas producers (and also potentially transmission businesses, if renewable gas production is more distributed), thus leading to dynamic efficiency benefits and lower costs to gas consumers in the long-run.
More diversified energy supply industry	• Creates a more diverse and resilient energy supply sector, as it facilitates the distributed, but scalable, storage of energy that is separate to the one (or small number) large pumped hydro schemes (e.g., Snowy), noting that: ○ (a) these are likely to be the main alternative means of harnessing increased intermittent renewable energy generation; and ○ (b) the market is unlikely to appropriately price in the risk of a low probability, high consequence, single-mode asset failure event.

27 There are a number of other examples of existing electricity price signals that may theoretically inhibit the efficient take-up of renewable gases. For example the National Electricity Rules prohibit distribution businesses from charging for exported energy, even where there is a direct nexus between having to facilitate the export of that energy and their future costs. Everything else being equal, this reduces their incentive to adopt alterative solutions to the export of that energy to defray a distributors future cost, for example, by investing in technologies such as distributed hydrogen facilities, which would use that excess energy to power the creation of renewable gases. More broadly, existing electricity transmission pricing arrangements are based on an open access arrangement that only applies shallow connection charges to connecting generators. This tends to result in load customers funding investments in the transmission network to enable either the export of energy from a generator or to relieve congestion where necessary. Whilst this approach is likely to change in the future under the AEMC's proposed COGATI arrangements (if implemented), it is an example of where inefficient pricing signals could, everything else being equal, lead to inefficient underinvestment in other options for using that renewable electricity generation (including directing that renewable energy into the production of renewable gases, instead of injecting it into an already congested electricity transmission network). Another example is distribution businesses continued reliance on consumption-based (kWh) charges to recover material portions of their overall revenue requirements, even where smart metering is in place and would allow them to adopt more cost-reflective demand (in particular, critical peak) charges to signal their cost of catering for forecast peak demands on their network. If gas customers in Victoria - which has the largest residential and commercial gas usage in Australia - were to switch on mass from gas to electricity, there would be significant network-related costs incurred in catering for the very large increases in winter peak demands. Current price structures provide no signal related to winter peak demand. Everything else being equal, this could lead gas customers to make inefficient switching decisions, as the marginal cost to the electricity supply system that would result from catering for this increased winter peak demand would almost certainly exceed the price signal upon which the switching decisions were made (a flat, kWh charge), which would be to the detriment of overall costs and therefore customers in the long-term.

Counteract the negative impact transient imbalances in the natural gas market might have on customers	• Assists the industry in riding through what some might consider to be temporary or transient imbalances in the natural gas market (e.g., due to moratoriums on gas exploration; and the impact of LNG facilities on domestic gas prices). • If these imbalances are temporary, yet they incentivise customers to permanently disconnect from the gas network and, consequent to this, gas distribution networks to permanently cease providing services to the market, then inefficient outcomes would ensue in the long-run.
Reduces emissions	• Would lead to lower emissions, particularly if part of the renewable energy that is used to power the creation of the renewable gases that are injected into the gas system, would have otherwise been curtailed (or not have been built), which is potentially the case given the current hosting capability of certain parts of the electricity transmission system where renewables are more likely to be sited, as well as distribution systems in the NEM.
Creates future optionality	• The creation of a blending scheme would lower barriers to market entry and reduce investment risk for providers of new technologies used to support the provision of renewable gases. This would facilitate the creation of a domestic renewable gas industry that in turn gives the option (if market conditions are suitable in the future) of pursuing: (a) export markets for, in particular, hydrogen; (b) full conversion of the natural gas system to renewable gases, including hydrogen or renewable methane; or (c) other domestic markets for renewable gases (e.g., mobility, chemicals, etc.).

6. Foundational issues to be considered in the design of any Blending Scheme

We believe policymakers would be likely to give explicit consideration to a number of overarching objectives if they were to design a Blending Scheme that sought to deliver outcomes that are in the long-term interests of customers.

These include that such a Scheme must:

- Achieve a *sufficient scale* of renewable gas injections into Australia's natural gas networks, otherwise the Scheme is unlikely to deliver any long-term benefit to consumers;
- Facilitate the achievement of the blending target at the *least cost* to the community; and
- Be designed in a way that *constrains* the financial impact on customers to levels that most customers are unlikely to notice or be unduly affected by, and which limits the distributional impacts of the Scheme.

Following on from this, the following table summarises a number of the foundational issues that we have considered in the design of any Blending Scheme, given the aforementioned objectives.

Table 2: Key issues that must be considered when developing a Blending Scheme

Criteria	Description
How should the long-terms interests of consumers with regards to the cost of the Scheme be reflected in its design?	To protect the long-term interests of customers, consideration could be given to making any Target/s adjustable under certain pre-defined circumstances over the Scheme's duration. This would ensure that Targets could reflect new circumstances or information, for example, with regards to the costs of the Scheme (and hence the impact on customers' bills). Notwithstanding the above, any flexibility would need to be achieved without unduly adding to the risks and therefore costs of the Scheme, and considered against other options for minimising the risk to customers (e.g., passing this risk on to Government).

Should the Target/s be National, State-based or distribution business specific, in order to facilitate the key objectives of the Scheme?	Some locations in Australia have an underlying competitive advantage in the production of renewable gases. For example, some parts of Australia have abundant, low-cost renewable energy supplies that can be harnessed to power electrolysers to make hydrogen from various sources of water. Whilst a Target could, *ex ante*, seek to estimate these types of underlying cost differences and then reflect those cost differences in State-based (or distribution business) targets, another, and generally preferable way would be to design the system such that locational production decisions are left to the market, which should incentivise production in locations that provide these competitive advantages. Therefore, *everything else being equal*, a Scheme should not be overly restrictive in terms of setting targets by region[28] – rather, the location of renewable gas plants and injections into the natural gas network should be driven by the market[29], which in turn would reflect these types of comparative advantages.
What types of renewable gases should be included in any Scheme in order to achieve its overarching objective?	There are a number of potential renewable gases that could be reflected in any Scheme – for example, hydrogen generated from the use of surplus renewable electricity generation, biomethane from upgrading biogas and renewable methane from the use of renewable hydrogen gas and carbon dioxide. Some of these products will also link with other markets, both nationally and internationally. If the sole objective of the Scheme is to achieve a pre-defined Target at the least-cost, then *everything else being equal*, separation of the markets for different technologies will lead to much smaller and less liquid markets. Therefore, the Scheme should not be overly restrictive in terms of the types of gases it incentivises[30]. Rather, the types of renewable gases[31] incentivised under the Scheme should be driven by the market, which in turn would reflect the underlying difference in production costs (amongst other things). If Government has an objective of promoting a particular renewable gas technology(s), then this could be achieved through targeted investment mechanisms such as Australian Renewable Energy Agency (ARENA) or the Clean Energy Finance Corporation (CEFC), as opposed to catering for this via the Scheme's design (e.g., the use of sub-targets for different technologies).

7. Scheme Design Options

There are a number of mechanisms that could conceptually be adopted to address the stated objectives of the Scheme. These mechanisms are summarised in the following table.

28 Or setting a global target that is too close to the technical limitations on the blending of hydrogen into natural gas pipelines, which would effectively lead to regional targets being created.

29 Obviously, this is subject to not breaching any technical or safety standards.

30 Subject, obviously, to not breaching any technical or safety standards or requirements.

31 As stated earlier, the Scheme could also be easily extended to include non-renewable but low-emission forms of hydrogen such as SMR with CCS, if policy-makers so desired.

Table 3: Scheme design options

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
Certificate-style scheme	• Places an obligation on liable entities (e.g., retailers, distribution businesses) to surrender a certain number of certificates each year. This creates an underlying demand for certificates. • Criteria supporting certificate creation is required (e.g., that they relate to the production and injection of certain accredited renewable gases into a licensed natural gas system). • Once defined, a parallel market for certificates is established and their price is set following demand and supply conditions (forced by the obligation).	• Production of eligible gas is decoupled from the location at which the liability is generated (e.g., certificates in one location can be used to offset liabilities generated from the sale of gas in another location), hence giving locational flexibility to production. • Certificate prices, and hence the costs of the scheme, should reflect underlying market fundamentals affecting the creation of the certificates. • It mimics the existing RET scheme, hence it could build upon an existing set of governance and institutional arrangements. • Provides a clear investment signal and, if the target is long term, can facilitate the establishment of long term industry infrastructure and capacity.	• Likely to have higher administrative costs relative to some other Schemes due to the need to implement compliance and verification systems/arrangements (despite it building upon existing governance and institutional arrangements). • Requires a sufficiently large market for the production of accredited gases, otherwise, producers could exert market power. • May require reasonably high penalties[32] (well above the marginal cost of generation) to incentivise compliance through the surrender of certificates, instead of through the payment of the penalty price. • Depending on the specific circumstances affecting the industry, in theory, allowing the use of existing facilities to generate certificates could lead to windfall profits without delivering any broader efficiency benefits. • The Scheme must operate for both a (a) pre-specified and (b) material length of time, otherwise it will create significant uncertainty for investors which will diminish the incentives to invest under the Scheme.

32 It should be noted that there is a trade-off here, in that setting the penalty price too close to the expected incremental cost of generation (as compared to the production of natural gas) increases the risks that liable entitles may be commercially better off to simply 'pay the penalty price' instead of going to the market for certificates. However, setting the penalty price too high may increase the overall costs of the scheme, if the market fails to develop in a manner that leads to the equilibrium price of certificates being below this level. For the avoidance of doubt, if a retailer chooses to simply pay the penalty price instead of procuring otherwise cheaper certificates from the market, competitive pressures should be such that that retailer is unable to pass on those higher costs to its customers.

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
Feed-in tariff (FiT) scheme	• A set payment level per unit of renewable gas is established by a central body for a certain volume (which is potentially adjustable periodically), which is payable to producers of accredited gases who inject their product into specified gas networks. • Bid selection is on a first-come, first-served basis until a desired quota is completed, after which the FiT ceases for new entrants.	• It is a known scheme design, as it is analogous to a number of schemes that were used by some states to promote investment in (predominately small scale) renewable electricity generation facilities. • Simple to understand and it is likely to have relatively low transaction costs. • Mitigates the risk that renewable gas producers could exercise market power to affect prices. • Depending on the duration of the posted FiT rate, provides income certainty to proponents.	• If renewable gas production were to have naturally occurred under a 'no scheme' option (i.e., they would have been built, even without the FiT), then the Scheme generates no economic benefit (it simply represents a wealth transfer) • The FiT may not reflect underlying market fundamentals, as the payment level is set centrally, *ex ante*. Moreover, if this centralised approach leads to a FiT level that is too low (relative to the underlying market fundamentals), not enough renewable gases will be incentivised, whereas if it is set too high[33], overpayment will occur to the detriment of consumers.
DBs to purchase their UAFG[34] requirements from renewable gas sources	• Places an obligation on distribution businesses to procure accredited gases within their own service territory to meet their own UAFG obligations	• Reasonably simple to implement • Minimal lead time to implement.	• Limited locational flexibility if the renewable gases must be injected into a distribution business' own service territory to meet their own UAFG target. • UAFG varies across distribution businesses, hence it may create distributional issues stemming from the adoption of such a Scheme, with customers served by distribution businesses with higher UAFG percentages contributing more than those connected to businesses that have lower UAFG percentages. • Monopsony power (one buyer) within each distribution region, which may affect potential producers' willingness to enter the market

33 An example of this was the NSW Solar Bonus Scheme, which was originally set at a very high 60c/kWh, based on the gross amount of production from PV systems installed under the scheme. This led to an incredibly large, initial take-up, that well exceeded expectations, indicating the rate was set significantly higher than levels that would have been revealed by the market.

34 Unaccounted for Gas (UAFG) is the difference between the measured quantity of gas entering the gas distribution system from various supply points and the gas delivered to customers.

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
			• Retailers are required to purchase UAFG in Victoria[35] whereas it is the distributor who purchases UAFG in other states. This limits the ability to adopt a one-size-fits-all approach across Australia, which has implications for administrative costs. • There is a risk that some stakeholder may see the linking of any renewable gas scheme to a business' UAFG value as weakening the incentive for distribution businesses to seek out economically efficient ways for reducing their overall UAFG footprint.
Reverse auction scheme to procure renewable gases	• Government or utility calls for offers of renewable gas in set tranches (sizes), and the most cost-effective and feasible proposals receive a long-term contract or funding support • Least cost means of meeting tranche thresholds adopted (s.t any other related criteria)	• Provides some flexibility around the timing, size and location of tranches, hence the mechanism can have regard to the supply/demand fundamentals at that time (noting however that too much flexibility may create too much uncertainty for the industry) • Outcomes are market tested • Contributions can be capped via the setting of reserve prices, hence providing a means of managing the costs to consumers. • In principle, auctions maintain many of the advantages of feed-in tariffs (income certainty for winning proponents) and are also capable of minimising costs to end-users.	• High set-up costs, which is particularly important if the size of the auction tranches is relatively small. • High transaction costs for bidders due to high upfront project development costs, which may preclude smaller bidders from bidding.

35 If actual UAFG is greater than the benchmark, the relevant gas distributor is required to compensate the retailers for the UAFG in excess of the benchmark, and vice versa.

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
Climate Solutions Fund	• Rely on funding through the Australian Government's existing Climate Solution Fund (previously known as the Emissions Reduction Fund) • Provides $2 billion towards reaching Australia's 2030 emissions reduction target.	• Relies on an existing Government scheme, hence potentially minimises the set-up costs and lead time to implement. • Theoretically, it integrates renewable gas solutions with other emissions reductions solutions.	• Whilst the use of low emissions gas is supported by a number of the prescribed abatement methods: the Industrial Electricity and Fuel Efficiency method and the Landfill and Alternative Waste Treatment methods; it is our understanding that these methods do not readily support the use of low emissions gas transported in a natural gas pipeline. • In the case of Landfill and Alternative Waste Treatment methods, reliance on the Climate Solutions Fund still does not overcome the underlying incentive to direct captured methane to the production of renewable electricity in order to generate RET certificates, as opposed to renewable gas, even if the latter is more efficient.

8. Preferred Scheme Design

Whilst each of the above approaches have certain advantages and disadvantages, on balance, we believe that a certificate-style scheme is conceptually, likely to be the most appropriate means of incentivising the blending of renewable gas into Australia's gas networks. We base this recommendation on the following key observations regarding the alternative design options:

- **Feed-in-tariffs (FiT):** The significant drawback of a FiT arrangement is that:
  - The rate is set *ex ante*, and hence cannot reflect underlying market fundamentals at the time (it can only forecast them); and
  - Therefore, if this centralised approach leads to a FiT level that is too low (relative to the underlying market fundamentals), not enough renewable gas will be produced under the Scheme, whereas if it is set too high, overpayment by consumers will be the inevitable result.
- **UAFG:** The main drawback with this scheme is that by requiring each gas distribution business to source their UAFG requirements from renewable gas producers in their own service territory, the scheme would in effect be creating a location-specific requirement. Everything else being equal, if the cost of producing renewable gas differs across regions, this approach will impose higher costs on the community relative to a scheme whereby production of renewable gas is decoupled from the location where the liability is generated (e.g., certificates in one location can be used to offset liabilities generated from the sale of gas in another location)[36]. For the avoidance of doubt:
  - There would be nothing prohibiting a distribution business from procuring renewable gas certificates as part of meeting their UAFG requirements under a certificate-style scheme approach, if they wanted to (or their customers expressed a willingness to pay) activate the renewable gas market. The difference would be that the physical location of renewable gas production used to generate those certificates would be underpinned by market fundamentals[37], not by the location of the UAFG injection requirement; and
  - The recovery of the costs would be subject to the existing tests under the National Gas Rules, which are discussed in more detail in a latter section of this report.

36 We note that this does not take-away from the fact that many costs differ across distribution businesses, due to factors such as geography, customer density, and asset age. We don't see this as a reason to not adopt a Scheme that would in theory lead to the least cost means of producing renewable gas.

37 This is similar to the ACT's 100% renewable energy target, whereby the Government expressly states that the "*location of the renewable energy supply needed to reach the ACT's target isn't critical to our emission reduction effect. We source our renewable energy from generators located across eastern and southern Australia*".

https://www.environment.act.gov.au/energy/cleaner-energy/renewable-energy-target-legislation-reporting

- **Reverse auction scheme:** Whilst there are a number of significant advantages associated with this scheme, our main concern relates to the administrative costs associated with setting up a centralised reverse auction scheme (particularly early on in the Scheme's implementation, where auction tranches are likely to be for smaller quantities). We also have concerns with regards to the potential for bidders to be exposed to high transaction costs upfront in the project development stage, thus creating a barrier to entry (this is of particular concern where there are a larger number of smaller bidders, which may be the case for the electrolyser market where production is likely to be more modular[38]). Finally, we note that this type of procurement arrangement could in fact be used by producers (or project proponents) to procure renewable gas production under a certificate-style scheme, if it is deemed to be efficient.
- **Climate Solutions Fund:** Relying on the existing Climate Solutions Fund would not, in and of itself, overcome the underlying incentive to direct captured methane to the production of renewable electricity, as opposed to renewable gas, even if the creation of renewable gases was the most efficient use of that gas. This issue particularly applies to Landfill and Alternative Waste Treatment methods.

In comparison, we have placed significant weight on the fact that a certificate-style scheme:

- If designed correctly, decouples the production of renewable gas from the location where the liability is generated; hence, everything else being equal (e.g., transportation costs), incentivising the production of renewable gas to be located where it is cheapest to produce;
- Generates certificate prices, and hence costs, that reflect underlying market fundamentals, which overcomes the inherent issue with a FiT arrangement that relies on a centrally administered, *ex ante* rate being set (with all the associated risks that stem from that);
- Mimics the existing RET scheme, hence the existing suite of governance and institutional arrangements should be able to be utilised (or require minimal change to be used);
- We doubt that the market for renewable gases will feature or be affected by significant market power issues, as:
  - It is our understanding that there are no market power[39] concerns related to the underlying technologies that are likely to be used to generate renewable gases (e.g., there are multiple, credible manufacturers of electrolysers);
  - There are no market power concerns related to the provision of renewable energy, which is likely to be the key input into the renewable gas production process; and

38 For example, the CSIRO, in the National Hydrogen Roadmap stated (page xvi): "*Electrolysis provides a more modular, distributed option that can scale according to demand. It is therefore more likely to meet the majority of hydrogen demand prior to 2030 …*".

39 If there were, market power in this part of the value chain could in turn lead to market power issues in the generation of renewable gases, which in turn would affect the market for Scheme certificates.

- There are multiple renewable gases, for example, renewable hydrogen and biogas, thus, further mitigating the risk that one or a few renewable gas providers may be able to exert market power[40].

Overall, at a conceptual level, we are of the view that a certificate style scheme is, on balance, the most appropriate means of incentivising renewable gas being blended into gas networks in Australia.

9. Implementation issues

The following table summarises a number of specific design and implementation issues that need to be considered, and our initial view regarding each of those issues.

Table 4: Design and implementation issues

Design issue	OGW's comment
Which category of businesses should be liable for surrendering certificates?	• In the absence of any other limitations, we would recommend that the Scheme would be applied to Licenced Gas Retailers (of a certain size threshold[41]) operating in the various Australian States. This approach is likely to have lower administrative costs than alternatives such as placing the obligation on gas producers or distribution businesses, as most retailers are already liable under the RET scheme, hence they may be able to utilise some of their existing processes and procedures to comply with this new Scheme. Moreover, allocating the liability to retailers separates the liable party (and hence the party that must purchase certificates) from the party that is potentially providing access to the infrastructure required to get the product to market. • That said, if it is not possible to get a retailer-liable scheme implemented in the near term[42], then we would recommend that the liability be placed on "covered" (or 'Scheme') "distribution" pipelines in the short-term. This should ensure that the Scheme is up and running in a timely manner. If this outcome occurs, the liability obligation could pass to retailers within 2 to 3 years of the commencement of the Scheme.

40 Any risk would be further mitigated if the Scheme was extended to include non-renewable, low-emissions sources of hydrogen such as SMR with CCS.

41 Our rationale for this is that there will almost certainly be some scale efficiencies related to a liable retailer's administration of the Scheme. Therefore, to avoid creating an additional barrier to entry into the retail gas market (or a competitive disadvantage for existing small gas retailers), smaller businesses (who may otherwise face disproportionately larger costs associated with complying with the Scheme if it were to be applied to them) should be excluded or offered the right not to participate for some period (as they may well want to still participate from the start of the scheme).

42 In saying this, the implementation of such a Scheme may be seen by some retailers as having a negative impact on their broader gas business. This would particularly be the case for those retailers that have large upstream positions in the natural gas market that may potentially be subjected to more competition as a result of this Scheme. This may affect their willingness to engage in the development of the Scheme. There may also be other transitional issues that we are not aware of that may affect retailers' ability to implement the Scheme in the short-term.

	• For the avoidance of doubt, if distribution businesses were to be made liable, there would be no obligation on that entity to surrender certificates related to renewable gases that have been injected into their own network - that is, the certificates surrendered[43] could be from plants that are located in other distribution business' service territories.

On what basis should each entity's liability be determined in a year?	• We would recommend that a retailer's liability be based on their total gas sales[44] in a previous year to customers in qualifying distribution regions, multiplied by the target blending rate for the year in question. This would give a GJ target[45] for a target year, which would then need to be converted **to a volume target** based on the relative energy per cubic metre of natural gas as compared to hydrogen.
	• More specifically, the "proportion of total gas sales" should be based on that entity's most recent audited gas sales (in GJ, again, adjusted to reflect the relative energy per cubic metre of natural gas vs hydrogen), most likely year t-2, to customers who are connected to "covered" (or 'Scheme') "distribution" pipelines. Our rationale for linking a retailer's liability[46] to sales on "covered" (Scheme') distribution pipelines is:
	  ○ This data is likely to be both readily available and auditable, hence lowering administrative costs; and
	  ○ This approach is more likely to lead to a retailer's liability being de-linked from gas that is: (a) sold to very large industrials (as they are less likely to be connected at the distribution level), (b) sold to gas-fired power generators, (c) delivered on pipelines that only serve a single shipper; and (d) delivered on small capacity pipelines, all of who we think would be best excluded from the generation of liabilities. The reason for this is so that retailers exclude those customers from the certificate cost recovery process which we think is appropriate as these types of customers are more likely to be larger, trade-exposed customers.
	• To mitigate the risk that linking a retailer's liability to historical gas sales (t-2) leads to outturn blending rates that materially differ from the target percentages for a year (which would occur, if, for example, overall demand for gas distribution services declined materially between t-2 and year t), the outturn GJ target (again, adjusted to reflect the relative energy per cubic metre of natural gas v hydrogen for hydrogen) should be adjusted by AEMO's forecast percentage change in gas sales (as per their most recent Gas Statement of Opportunities), to customers connected to the relevant distribution businesses, or whichever category that AEMO uses that best relates to these types of customers, between t-2 and t. Whilst this adds marginally to the administrative costs of the Scheme, we think it represents an appropriate risk management tool.

What types of gases should be eligible for certificates?	• Our starting point would be that only 100% renewable gases be eligible for certificate creation, as this:
	  ○ Aligns with the RET scheme (e.g., gas fired power stations are not eligible for RET certificates, even though they have a lower emissions intensity than coal fired power stations); and
	  ○ Reduces the costs of administering and complying with the Scheme, as this approach should make verification more clear-cut.

43 For the avoidance of doubt, the liability relates to the *surrender of certificates, not the purchase of the renewable gas itself.* This means that distributors do not need to own the renewable gas that creates the certificates that they buy.

44 If the distribution business is the liable entity in the early stages of the Scheme, the number of certificates that they would be liable to surrender would simply be based on the volumes they deliver.

45 For the purposes of completeness, it is noted that whilst this could be easily converted to a carbon based target, carbon based targets may open up debates about gas basin and lower carbon gas sources etc, which, as stated, is not being presented as the underlying objective of the Scheme.

46 Note that this should not be confused with the "types" of pipelines that renewable gases can be injected into in order to be eligible create renewable gas certificates. This is discussed separately.

	• Furthermore, we would recommend that no sub-targets be set for different technologies (e.g., renewable hydrogen versus renewable methane), so that the communications around the Scheme can be framed around it being designed to maximise the potential sources (and therefore competition in the provision) of 100% renewable gases available under the Scheme, rather than to support the development of particular technologies. • We note that the latter, if a Government objective, could be achieved through complementary arrangements such as ARENA funding or other government innovation funding. • Notwithstanding the above, the Scheme could easily be extended to incorporate non-renewable, but very low-emission forms of hydrogen such as SMR with CCS, if policymakers considered this to be in the long-term interests of consumers[47].
On what basis should the target/s be set?	• We would recommend that a National, rather than a State-based or distribution-business specific, target be set so as to decouple the production of renewable gas from the location where the liability is generated. By relaxing the location of renewable gas injections - subject to not breaching any technical constraints - it enables renewable gas producers to seek out appropriate levels of scale efficiency, and to locate in areas that have the cheapest cost of production (everything else being equal)[48].

What facilities should be eligible for certificate generation?	• We would recommend that (a) both existing and new facilities be eligible to create certificates; subject to (b) those facilities injecting a certified gas <u>into certain types of pipelines </u>(see below).
	• The reason for recommending that both existing and new facilities be allowed is that:
	    ○ Any attempt to exclude existing renewable gas facilities adds to the cost of administering the scheme (e.g., how would an existing facility that expanded its production be treated);
	    ○ It is our understanding that this issue is likely to be relatively immaterial; and moreover
	    ○ To the extent that there are existing renewable gas plants in situ, it is our understanding that most are biogas facilities, and, moreover, most are currently used to produce electricity (not renewable gases). Everything else being equal, allowing these existing plants to generate renewable gas certificates would put the production of 100% renewable gas on a similar footing to the production of 100% renewable electricity, as these plants are likely to already be eligible for RET certificates (hence our proposed approach simply neutralises the impact that the loss of RET certificates might have on their conversion decision, and therefore is likely to lead to more efficient outcomes).

47 This is likely to require some form of weighting of certificates generated from these types of technologies. For example it could be that certificate prices received by SMR with CCS providers are discounted to reflect the lower level of emissions reductions they produce as compared to 100% renewable gases. The base would be relative to the emissions created by the consumption of natural gas. For the avoidance of doubt, whilst prima facie, lower certificate prices would incentivise liable entities to seek out these types of certificates to meet their liabilities (because they are cheaper), everything else being equal, the lower certificate prices incentivise less uptake of SMR with CCS as compared to 100% renewable gases.

48 We note that in practice, this may create a concentration of hydrogen production in specific areas where it is most economic to produce and inject into existing gas networks. This aligns with our previously stated objective for the Scheme, namely that it be designed to achieve the blending target at the least cost to the community. Such an outcome is consistent with what has occurred under the RET scheme. Whilst some may argue that this could impact on customers' support for the Scheme - if customer's in fact value the production of hydrogen in their own distribution network - we would observe that this does not appear to have been an issue with the RET scheme. That said, without testing customers' views on this, it is difficult to know what customers' views are exactly. As outlined in a latter section of this report, we recommend that a number of the key design parameters proposed be tested with customers in order to ascertain their views; this would be one of those design parameters that should be tested.

	• Our initial thinking is that eligible gases must be injected into a pipeline that is, or has been, subject to a **form of regulation**[49] under the National Gas Law (NGL) or the National Third Party Access Code for Natural Gas Pipelines (the previous scheme). A list of such pipelines is contained on the AEMC's website[50]. This would of course be subject to the technical capabilities of individual pipelines to safely cater for any injections[51]. In recommending this, we note that: ○ By expanding the scope for generating certificates beyond just injection into "covered" distribution networks, the Scheme would maximise the opportunities for renewable gas injection under the Target, whilst still adopting a clear criterion as to which pipelines renewable gas can be injected into to generate certificates. Everything else being equal, this should minimise the overall costs of meeting the target as the market would be much less constrained as to *where* renewable gas can be injected, hence it aligns with the overarching objective of the Scheme; ○ However, this could, in theory, lead to a material proportion of eligible gas injections occurring in pipelines other than "covered distribution" pipelines, hence the actually blending rates within Australian distribution networks (or specific Australian distribution networks) may be lower than the overarching target. If this is an issue to policymakers, then this could potentially be overcome via the application of some form of "soft" cap (e.g., no more than 20% of the overall target in any given year should come from renewable sources connected to pipelines that are not "covered" distribution pipelines; blending within each distribution business must be at least X% by the end of the Scheme).
At what percentage level should the final target be set, and how long should the scheme run for?	• The final Scheme target must balance a number of competing objectives: (a) it must be of a scale that is material enough to genuinely contribute to the overarching objective outlined earlier in the report; (b) it must be material enough to incentivise the pursuit of scale efficiency in the sizing of renewable gas plants; *yet* (c) it must not be so large that it either breaches technical limits or leads to, 'in effect', distribution-specific targets being created. This would occur if the national target is set at a level that is so close to the technical blending limits that to meet the national target, all distribution businesses need to be at or around the same level. • Given the assumption that many current appliances are already tested at up to a 13% hydrogen (by volume) blend, and assuming (conservatively) that there will be minimal blending outside of Australia's 'covered' gas distribution networks, a target in the order of 10% of volume[52] would appear to represent (a) a 'material' target, whilst also (b) providing reasonable flexibility to decouple the production of renewable gas from the location where the liability is generated.

49 This should not to be confused with the concept of a "covered" pipeline. Pipelines that have been subject to some form of regulation under the NGL could in fact be a covered or an uncovered pipeline. It is our understanding that there are around 130 of these pipelines in Australia.

50 https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register

51 For example, we understand that there may be some issues related to the injection of hydrogen into certain transmission pipelines above certain blending levels (as it may cause hydrogen embrittlement where hydrogen being absorbed into the metal makes the pipe brittle and prone to failure). Where this is the case, the pipeline operator could notify the market of their inability to accept injections of hydrogen above their nominated threshold level (or alternatively, it could be signalled to the market via a very high injection tariff). From a practical perspective, this would mean that most hydrogen would be injected into distribution networks. However, in saying this, it is our view that transmission businesses are likely to be incentivised to allow renewable gases to be injected into their networks, where it is economic and safe to do so, because by disallowing injections they are likely to incentivise the production of gases downstream of their network, which effectively facilitates the bypass of their network.

52 It should also be noted that for renewable forms of methane (biogas, renewable methane) the volume target would offer some 3 times the energy target for these schemes, potentially providing other scale incentives.

	• We would recommend that the Scheme operate for a minimum 15 years, reflecting the reasonably long-lived nature of assets required to provide renewable gases. This duration should also facilitate the 'bankability' of the Scheme in the eyes of investors.

How should customer's be protected in terms of the bill impacts?	• No matter what the final Target is, from a communications point of view, we think it is important that the Scheme's design include mechanisms that explicitly limit the financial impact it imposes on customers.
	• To manage this, we think an option would be to only set explicit volume blending targets for the early years of the Scheme's life (e.g., 0.5%, 3%), with a final year rigid target range also being set (e.g., 8-10%). Both provide the underlying certainty to investors about the Scheme's overall levels.
	• However, intervening targets could be set 2 years in advance. This lead time is suggested as it reflects a broad estimate of the lead time required to develop a project.
	• There would need to be rigid rules around how these intervening targets would be set so as to give investors enough certainty to support their long-term business models, whilst providing policymakers with some flexibility to manage customer impacts. The rules could include, for example:
	  o Specifying minimum incremental increases in the target (i.e., the target must increase by a certain percentage); with
	  o Any increment above the minimum level to only be approved if it is forecast to not exceed a pre-specified cap on bill increases (e.g., the Scheme must not add more than 1% per annum to the average residential customer's expected bill). The methodology to determine this would need to be set out in advance, but it would be likely to reference expected future renewable gas production costs and hence certificate prices, which in turn flow through to bill impacts. Furthermore, the Clean Energy Regulator (CER) could be charged with periodically publishing forecasts of future intervening targets.

Should certificate creators be allowed to "bank" certificates for future remittance?	• We believe that the ability for renewable gas producers to "bank" certificates will be an important feature, as this allows the potential for certificate generation to "run ahead" of any target at any point in time. • This aids the Scheme's flexibility, in that it allows proponents to (a) adopt scale efficient production decisions, without having to fully discount the value of the certificates that are generated from any efficient upsizing of plant, and (b) bring forward production of renewable gases if the costs of production fall such that it becomes economic to bring forward investment decisions (whilst still accruing some value to certificates that are not surrendered in the year they were created).
Should liable entities be able to defer their liabilities for a period?	• Yes, for a reasonably small, pre-defined window of time, for example, 3 years. This would enable liable entities to better match banked certificates with liabilities. It would also allow liable entities to reflect, via the timing of their surrender of certificates, forecast changes in the cost of producing renewable gases (and hence certificates). For example, if liable entities forecast dramatic declines in production costs (and hence certificate prices) in the near future, then the Scheme should incentivise this to occur in order to minimise the overall cost to the community. • The counterpoint is that the Scheme should not incentivise retailers to defer their liabilities too much towards the back-end of the Scheme's duration, as extended deferral periods may place at risk the actual injection of renewable gases into gas networks in the intervening period (which is obviously a key objective of the Scheme). It could also lead to significant retail bill shock once the deferral period ends. Any Scheme would need to also cover off how a liable entity's deferred liabilities are dealt with in the event that they exit the market. • A holding cost should be applied to any deferral, reflecting an estimate of liable entities' weighted average cost of capital.
Should a penalty price be included in the Scheme?	• A penalty price should be applied to liable entities in the event that they do not surrender certificates in a year (and they have not nominated to defer to a future year). • The penalty price should be set well above the estimated marginal cost of producing renewable gas (as compared to natural gas) so as to incentivise actual investments in renewable gas production.

	• If a retailer chooses to simply pay the penalty price instead of procuring otherwise cheaper certificates from the market, competitive pressures should be such that that retailer is unable to pass on those higher costs to its customers.
Who should administer and ensure compliance under the Scheme?	• The Clean Energy Regulator (CER) should regulate and oversee the Scheme. This could involve it validating certificates registered, and creating an on-line registry of certificates. This should be able to be built upon the existing REC Registry administered by the CER. • For the avoidance of doubt, this would also involve ensuring compliance with any 'certificate of origin' requirements, which allow tracing and certifying the provenance of renewable gases and the associated environmental impacts. Any certificate of origin requirement would need to align with the Scheme's underlying design, and include: o Criteria that would be used to support this assessment; and o Evidence that is required to be submitted to "prove" origin (e.g., electricity bills demonstrating the purchase of 100% of requirements from defined "green" energy schemes). • Secondary trading could occur outside of this formal process. This would be for certificates that have been validated by the CER, but which have not already been surrendered. A secondary trading market could involve financial institutions, traders or agents etc. • The CER could also be tasked with determining the number of certificates liable entities must surrender each year (in accordance with the broader Scheme requirements)
What would the role of pipelines be under the Scheme?	• Pipelines would continue to operate their systems in a way that allows them to meet all technical, environmental and safety standards etc. • To this end, they would have full carriage for ensuring that actual blending rates did not exceed technical limitations, which presumably would be managed through things like connection agreements with the renewable gas producers who are connected to their network. • There may be merit in expanding the information that pipelines periodically publish to the market, so as to provide guidance to existing and prospective renewable gas producers regarding outturn and forecast blending rates, areas where injections may be constrained, connection charging arrangements, etc
What should happen if there is a physical failure of a renewable gas plant, leading to transient imbalance in the market for renewable gas certificates?	• A force majeure (FM) mechanism could be useful to protect the market from the physical failure of plants, particularly in the early days of the Scheme. In particular, if there were only a small number of suppliers in total, liable parties may be particularly exposed to the physical failure of a small number of plants. • In the absence of a FM mechanism, one could expect to see a risk premium paid by customers.
How should different gas compositions be catered for in the calculation of residential bills?	• The composition of the blend will vary by location and possibly over the time of day/year (if, for example, hydrogen production was continuous, with swings in demand met by flexing natural gas flows). Moreover, the "average" blend will shift over time towards a higher composition of renewable gases. • That said, this is no different to what happens currently (although, admittedly, existing variations in gas composition are likely to be much less volatile that what would occur in the future under the proposed Scheme), with the application of "heating values" being used as the basis for adjusting for different gas compositions[53] • As such, prima facie, existing arrangements are likely to be able to accommodate gas of different compositions being injected into networks.

53 https://energylive.aemo.com.au/Innovation-and-Tech/Heating-value-allocation-model-system

10. Alignment with the National Gas Rule tests

In considering whether or not any capital or operating expenditure that is required to facilitate the achievement of a blending target meets the National Gas Rule (NGR) tests, we must first consider:

- What particular types of expenditure are likely to be required; and
- Given the Scheme design, which gas market participants will incur these expenditures.

In relation to the former, the types of expenditures that would be required include, but are not limited to:

- The costs of generating the renewable gas itself (e.g., water, electricity, the electrolysis plant);
- Costs of interconnecting that plant to the natural gas system (including metering and other devices required to measure the quality of the gas);
- Transportation services – whether it be both transmission and distribution, or distribution only; and
- Retail services.

At higher blending rates of hydrogen, there would also be (potentially significant) additional costs incurred in replacing customers' appliances, which, as we elaborate upon later on in this section, are unlikely to be recoverable under the Rules and more broadly, would appear to render much of the National Gas Law impotent due to the underlying definition of 'natural gas' in the Law ('*the principal constituent of natural gas must be methane*').

Based on the Scheme that we outlined in the previous section – one that assumes a moderate-level blending target – a network business' costs would be limited to facilitating the interconnection and transportation of renewable gases. To be clear, it would not be directly involved in the production of any renewable gases (although presumably, network businesses could provide these services to the market via a ring-fenced entity). Similarly, as they are not retailers of gas, they would not be liable entities under the proposed Scheme[54], hence they are not required to bear any of the costs of actually purchasing renewable gas certificates, although they could elect to if they so desired (this is discussed in more detail below).

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54 Unless they fulfil this role in the short-term for the reasons outlined in an earlier section. It should be noted that if network businesses were to fulfil this role, and in turn, incur costs associated with purchasing certificates, we would assume that this would be covered off under existing cost-pass through provisions. For example, we are aware of a number of regulated gas business (i.e., Jemena, APA, AusNet Services) whose Access Arrangement's contain a 'Relevant Pass Through Event' relating to a "Regulatory Change Event", that, on our reading, would cover it for the costs (subject to meeting any materiality threshold) of purchasing certificates under any Scheme that is introduced during a regulatory control period. Any forecast cost of purchasing certificates would, in our opinion, meet the requirements of r79 ('*to comply with a regulatory obligation or requirement*') and r91, as a '*prudent service provider would, acting efficiently, and in accordance with accepted good industry practice*', would clearly need to comply with any obligation imposed upon it via legislation to procure a certain amount of renewable gas certificates.

Regarding interconnection services, there would appear to be no barrier to a regulated distribution business charging a connecting customer for the reasonable costs of facilitating their connection to their network. This would apply to both customers who are seeking to inject gas into the network, as well as customers who are seeking to consume gas from the network. In saying this, we note that Jemena has proposed an "interconnection service[55]" in its most recent Access Arrangement proposal[56]. In particular, it outlines the terms and conditions (T&Cs) upon which they will provide the Interconnection Service. These T&Cs include that charges payable by the Prospective User include things such as "charges for engineering and associated investigations" and a "charge for construction and provision of interconnection facilities". It also states that[57]:

> *In addition, modifications may be required to the Network and/or the Service Provider's systems to facilitate the provision of the Interconnection Service. These requirements will vary depending on the nature and location of the Delivery Point or Receipt Point. The Prospective User will bear the reasonable costs of such modifications, whether identified before or after installation of the Delivery Point or Receipt Point, unless the Service Provider can recover costs from Users of the Delivery Point or Receipt Point.*

Finally, is also states that[58]:

> *For the avoidance of doubt, an Interconnection Service is separate from and additional to a service requested by a Prospective User or any other person for the transportation of Gas through the Network (including the Reference Service) from the Receipt Point or to the Delivery Point.*

The "Reference Services" referred to include a range of use of system tariffs that in the main involve charging customers for the volume of gas that they consume. That said, there would appear to be no barrier to a gas distribution business adopting an injection tariff as well – noting that this is a feature of APA's transmission tariffs for the Victorian DTS.

In summary, there would, on face value, appear to be no barrier to a pipeline business:

- Proposing an "Interconnection Service" thus allowing it to recover all reasonable costs incurred in providing for a renewable gas producer's interconnection into its network; and
- Potentially levying an injection tariff that provides a further price signal to the market with regards to where injection services could be most economically accommodated in their network.

55 Jemena defines an Interconnection Service as a "*service provided by the Service Provider to establish: (a) a Delivery Point to enable delivery of Gas from the Network into a Downstream Network; or (b) a Receipt Point to enable delivery of Gas into the Network from an Upstream Facility, on the terms and conditions agreed to by the Service Provider and Prospective User including those, to the extent applicable, contained in the Operational Schedule*".

56 JGN, *Access Arrangement, JGN's NSW gas distribution network, 1 July 2020 - 30 June 2025*, page 3

57 Ibid, page 60

58 Ibid, page 59

More broadly, if, after a connection has been made, a gas transmission or distribution business was forecasting to have to incur additional costs to facilitate the transmission or distribution of renewable gases to end customers, then presumably those expenditures would be able to be included into their opening capital base under Rule 77(2)(b), if they met the 'new capital expenditure' criteria (also known as 'conforming capex') outlined in the Rule 79.

(1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:

(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services; and

(b) the capital expenditure must be justifiable on a ground stated in subrule (2); and

(c) the capital expenditure must be for expenditure that is properly allocated in accordance with the requirements of subrule (6).

(2) Capital expenditure is justifiable if:

(a) the overall economic value of the expenditure is positive; or

(b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or

(c) the capital expenditure is necessary:

(i) to maintain and improve the safety of services; or

(ii) to maintain the integrity of services; or

(iii) to comply with a regulatory obligation or requirement; or

(iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity); or

(d) the capital expenditure is an aggregate amount divisible into 2 parts, one referable to incremental services and the other referable to a purpose referred to in paragraph (c), and the former is justifiable under paragraph (b) and the latter under paragraph (c).

(3) In deciding whether the overall economic value of capital expenditure is positive, consideration is to be given only to economic value directly accruing to the service provider, gas producers, users and end users.

(4) In determining the present value of expected incremental revenue:

(a) a tariff will be assumed for incremental services based on (or extrapolated from) prevailing reference tariffs or an estimate of the reference tariffs that would have been set for comparable services if those services had been reference services; and

(b) incremental revenue will be taken to be the gross revenue to be derived from the incremental services less incremental operating expenditure for the incremental services; and

(c) a discount rate is to be used equal to the rate of return implicit in the reference tariff.

(5) If capital expenditure made during an access arrangement period conforms, in part, with the criteria laid down in this rule, the capital expenditure is, to that extent, to be regarded as conforming capital expenditure.

(6) Conforming capital expenditure that is included in an access arrangement revision proposal must be for expenditure that is allocated between:

(a) reference services;

(b) other services provided by means of the covered pipeline; and

(c) other services provided by means of uncovered parts (if any) of the pipeline,

in accordance with rule 93.

For example, the criteria references the need to have regard for "*the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure*". If a business adopted an injection tariff that signalled the forward-looking marginal costs of accommodating new injections of renewable gas in an area (e.g., reflecting the need to replace existing cast iron distribution pipelines with high-density polyethylene pipes which are suitable for transporting hydrogen; the need for increased compression if required), then this would provide a foundation for such an assessment, as the renewable gas injection tariffs would be the "incremental revenue" against which the capital expenditure would be compared. The criteria also accommodates other cost-drivers such as safety-related expenditure and expenditures that are driven by the need to comply with regulatory obligations.

We see no limitation on the recovery of any operating expenditure under s91 that is related to any conforming capital expenditure approved under Rule 79.

The above discussion would appear to be broadly consistent with the AEMC's initial (unofficial) views, with a senior member of the AEMC stating at a recent conference that[59]:

No regulatory changes likely to be required if blend small amounts of hydrogen into natural gas pipelines, except for changes to the definition of "natural gas" in the Law so pipelines remain regulated

In that same presentation, the presenter indicated that if there was a move to higher amounts of hydrogen in distribution pipelines, "*significant issues are likely to arise in relation to managing the transition, eg who bears the costs of new or replaced assets and customer appliances, how do you assess the efficiency of the required expenditure, how do you manage safety issues*".

To this end, we highly doubt that any expenditure "beyond the meter" (i.e., within customers' premises) would meet the existing requirements of Rule 79. In particular, the definition of a pipeline in the National Gas Law explicitly <u>excludes</u> "*anything downstream of a point on a pipeline from which a person takes natural gas for consumption purposes*", yet for it to be conforming, it must be related to a "pipeline":

*"conforming capital expenditure that is included in an access arrangement revision proposal must be for expenditure that is allocated between: (a) reference services; (b) other services provided by means of the **covered pipeline**; and (c) other services provided by means of uncovered parts (if any) of the **pipeline**, in accordance with rule 93."*

59 Richard Owens, *Gas Pipelines: Have we got the regulatory balance right?* ACCC/AER Regulatory Conference, 1 August 2019

Therefore, any increase in blending levels of hydrogen above those able to be accommodated by existing appliances would need to be market driven[60] – that is, the benefits to specific end customers of being able to access more hydrogen (e.g., 100%) would need to outweigh the additional costs that they incur in switching to hydrogen-ready appliances. This could feasibly occur if the difference between the cost of hydrogen (after accounting for the value of any renewable gas certificates whilst the Scheme was in place) and the cost of natural gas, exceeded the cost of swapping over appliances.

Finally, as we stated earlier, distribution businesses would not be required to bear any of the costs of actually purchasing renewable gas certificates under a retailer-liable scheme, although they could elect to purchase renewable gases to meet their UAFG requirements if they so desired. If they choose to do this, then expenditure would be treated like any other expenditure under the Rules. In particular, Rule 91 requires that operating expenditure:

> *"must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services".*

Whilst the explicit reference to "efficient" and "lowest sustainable cost" is, on face value, likely to mean that shareholders have to bear any additional costs of procuring renewable gases for UAFG purposes (if their cost exceeds the cost of procuring natural gas, after accounting for the value of any renewable energy certificate), the National Gas Law states in 28(1) that:

> *The AER must, in performing or exercising an AER economic regulatory function or power—*
>
> > *(a) perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national gas objective*

In theory, this may provide an avenue for distributors to justify the recovery of the efficient costs of procuring renewable gases, *if* they can *clearly* demonstrate that their customers are willing to pay[61] the incremental costs associated with that procurement decision as compared to the procurement of natural gas for UAFG purposes. This could be the case, even prior to the commencement of any Scheme.

11. Next Steps

There are a number of logical next steps that the ENA should consider undertaking if it wishes to further pursue the introduction of a Renewable Gas Blending Scheme. These include, in order:

- Undertaking further consultation with customers to assess their:
  - Views regarding the creation of such a Scheme, and more specifically, whether there are any particular aspects of the Scheme that they are strongly supportive of, or conversely, strongly against, which in turn may be used to adjust the proposed Scheme's design; and

60 This approach also applies once the Scheme ended. That is, any further penetration of hydrogen should be market driven.

61 For example, via the use techniques such as Contingent Valuation analysis or Choice Modelling.

  - Willingness to pay for the injection of renewable gas into Australia's gas networks, with a view to utilising the results as part of a broader, more detailed, cost-benefit (CBA) analysis (see next step);
- Undertaking a detailed CBA of the Scheme, aligned to the Regulatory Impact Statement (RIS) assessments that policymakers are likely to undertake. This CBA should have regard to the benefits ascribed to the proposed Scheme in this report, including, but not limited to:
  - The economic cost under the base case (no policy) of inefficiently using biogas in the production of electricity as opposed to renewable gas;
  - The economic cost under the base case (no policy) stemming from the Government relying on its Climate Solutions Fund to meet its climate objectives, as compared to reducing carbon emissions under the proposed Scheme;
  - The economic benefits stemming from facilitating renewable gas as a competitor to natural gas, with this covering both wholesale and transmission market benefits;
  - The economic benefits of having more dispersed production of gas, for example gas supply diversification benefits (e.g., reduced risk stemming from a major gas facility outage);
  - The economic benefits of having a more dispersed energy storage solutions; and
  - The economic benefits resulting from any reduction in the rate of switching from gas to electricity resulting from the introduction of the Scheme (defraying the marginal costs that would need to be incurred in the electricity sector to accommodate the additional energy requirements stemming from this switching).
- Informing Retailers of the ENA's proposed Scheme, the results of the CBA and customer feedback, along with the components of the proposed Scheme design that would directly impact upon their operations. This would allow the ENA to outline first-hand to Retailers, why it supports the introduction of such a Scheme, and moreover, to explain the role the ENA sees the Retailers undertaking under the proposed Scheme and why it proposes that role, with a view to ascertaining Retailers' perceptions of this component of the Scheme design;
- Conducting detailed discussions with key external stakeholders outlining the details of the proposed Scheme, customers' views of the proposed Scheme (and how the ENA has adjusted the proposed Scheme to accommodate customers' views), and the results of the CBA analysis. The key external stakeholders that should be consulted are likely to include, but not be limited to:
  - Representatives from the Council of Australian Governments Hydrogen Working Group, Steering Committee and Stakeholder Advisory Panel;
  - The Department of Industry, Innovation and Science, which supports the working group by coordinating the activities of the Australian and state and territory governments in developing the strategy;
  - The CER, particularly regarding their role under the proposed Scheme design;
  - Relevant state-based Government Departments; and
  - Energy Consumers Australia.