Renewable Gas:

Policy Options to Support Australia's Decarbonisation Journey

Executive Summary

KPMG

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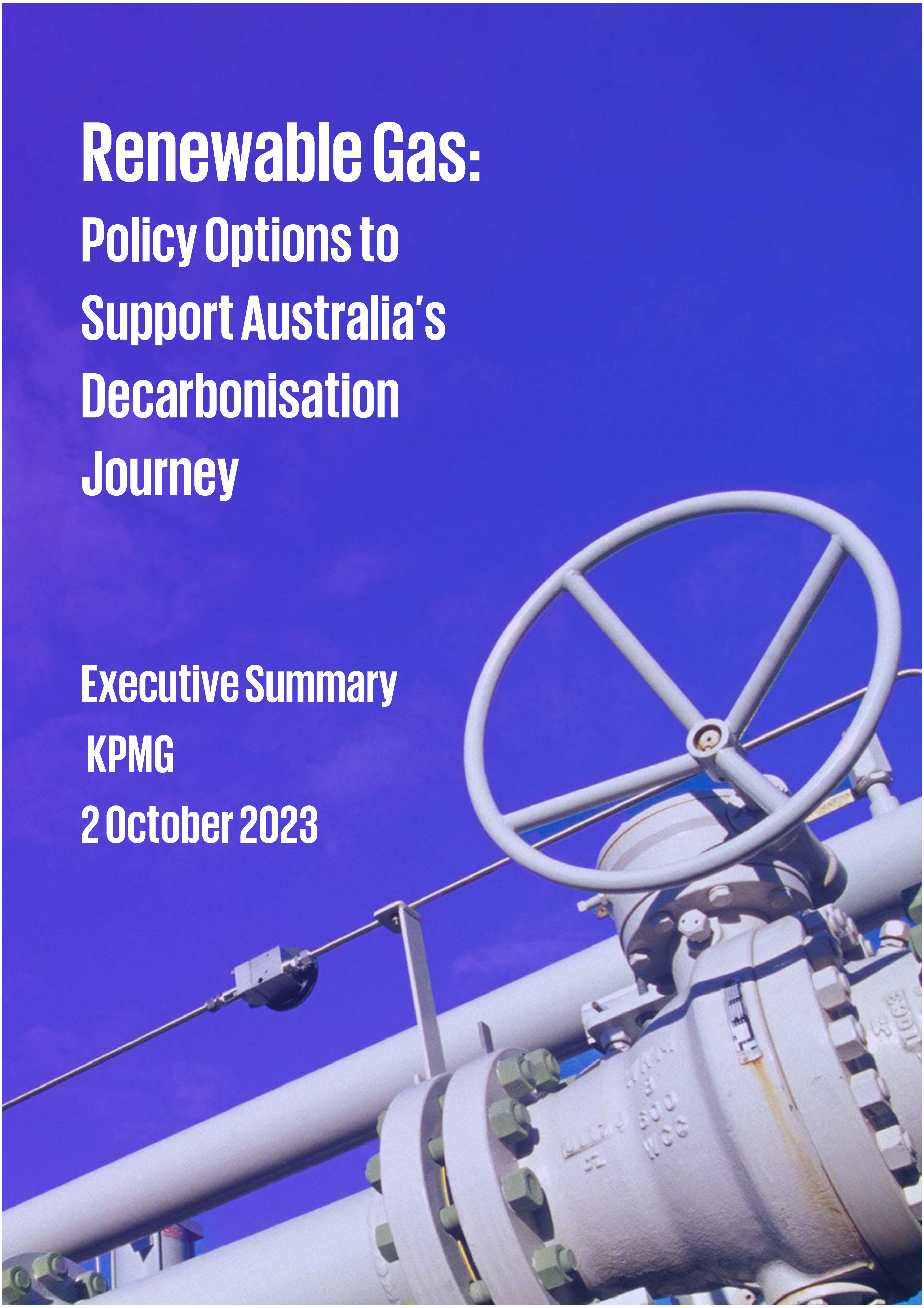

1 Executive Summary

1.1 About this report

KPMG has prepared this report for Energy Networks Australia to examine the policy settings needed for renewable gases to contribute to Australia's net zero journey. The report presents KPMG's independent analysis of the potential role of renewable gases in the net zero transition and the policy settings required to ensure that this potential is realised. We pay particular attention to options for deployment incentive schemes, and provide recommendations for how such schemes could be designed in the Australian context.

Our scope is to consider green hydrogen and biomethane only, as the two most prospective renewable gases. Green hydrogen is produced from electrolysis using renewable electricity, and provides a renewable, low-emissions form of energy. Our analysis also includes the range of green hydrogen derivatives, such as green ammonia and synthetic methane. Blue hydrogen, which is produced from fossil fuels with carbon capture and storage, is outside the scope of this analysis. We also consider biomethane, which provides another form of renewable, low-emissions gas that is produced from the anaerobic digestion of biomass. Other forms of bioenergy, such as liquid biofuels, are not within the scope of this report.

1.2 The potential role of renewable gases in the net zero transition

Renewable gases such as green hydrogen and biomethane have the potential to deliver GHG emissions reductions by displacing conventional natural gas and other fossil fuels in the energy system.

The International Energy Agency (IEA) acknowledges that the pathway to net zero requires us to employ renewable gases for dispatchable electricity, long-term energy storage, and to decarbonise hard-to-abate sectors such as heavy industry, transport and agriculture.[1] In the electricity and energy sector, renewable gases can reduce the carbon footprint of gas-fired peaking generation used to complement variable wind and solar, while green hydrogen can be used for long-term renewable energy storage. Meanwhile, there are important applications for renewable gases in the industrial sector (such as chemical production, plastics, steel, cement, glass and food and beverage), either as a source of high-temperature heat or as a chemical feedstock. Other hard-to-abate sectors with renewable gas applications include heavy-duty long-distance transport (such as trucks, ships and planes) and agriculture (ammonia for fertiliser production).

Renewable gases are likely to play a role in the built environment sector, alongside energy efficiency and electrification. In its updated roadmap to net zero,[2] the IEA describes how energy efficiency provides the first pillar of the transition for the buildings sector, while electrification and switching to low-emissions fuels provides the second. Although electricity is expected to supply two thirds of the global energy requirement for buildings in 2050, low-emissions gases such as biomethane and hydrogen play a bigger role in 2050 in regions with high heating needs, dense urban populations and existing natural gas networks.

For Australia's built environment sector, there is a need to clarify the long-term role of renewable gases in distribution networks. Even under a 'rapid electrification' scenario, Net Zero Australia forecasts that gas distribution to homes will have a long tail, and only cease by 2050 in favour of electrified heating and cooling, due to the lengthy average lifespan of gas appliances (20 years). Net Zero Australia calls on policymakers to decide whether existing gas distribution for commercial and household customers should be repurposed to a zero-carbon fuel (such as biomethane), communicate this decision to consumers and explain its implications for their choices.[3]

[1] IEA Bioenergy. The role of biogas and biomethane in pathway to net zero. December 2022.

[2] IEA. World Energy Outlook 2022. November 2022.

[3] Net Zero Australia. How to make net zero happen: Mobilisation report. July 2023.

1.3 The current state of renewable gas markets

1.3.1 Production volumes

Globally, the green hydrogen market is in its infancy, with less than 1% of global hydrogen produced today produced from renewable energy. Hydrogen makes up around 2.5% of global final energy consumption, with the EU and US considered major markets. Australia is currently not a major global producer or consumer of hydrogen but is host to a significant investment pipeline of green hydrogen projects.

Compared to green hydrogen, the global biomethane market is more mature. Global biomethane production was 7.4 billion cubic metres (bcm) in 2022, with the EU producing 3.6 bcm and the US producing 2 bcm. However, the biomethane market in Australia is not yet established, with Jemena's Malabar Biomethane Demonstration Plant the only current biomethane facility in operation.

1.3.2 Policy settings

Renewable gases are receiving growing policy attention in Australia. Australia's National Hydrogen Strategy sets out the strategic framework for hydrogen and is being updated, and the recently announced Hydrogen Headstart scheme commits $2 billion towards hydrogen projects. There is currently no strategy specifically focused on biomethane but the Australian Renewable Energy Agency (ARENA) commissioned a Bioenergy Roadmap in 2021. Both the Commonwealth and States have supported many renewable gas research and development (R&D) and pilot projects. Meanwhile, in terms of broader climate policy settings, the Safeguard Mechanism and Emissions Reduction Fund provide important indirect incentives for renewable gas uptake.

However, domestic policy settings are less advanced and ambitious than international partners. The Inflation Reduction Act (IRA) in the US includes production tax credits for clean hydrogen and directs US$10 billion in funds and investment tax credits to incentivise the development of biogas facilities. The European Hydrogen Strategy has an objective to produce 10Mt of renewable hydrogen in the EU by 2030, and the REPowerEU Plan commits to increasing Europe's annual production of biomethane to 35 bcm by 2030.

1.4 Priorities for Renewable Gas Policy

We identify three priority areas for policymakers: setting market and regulatory foundations, stimulating production to drive down costs, and managing social license and spill-overs.

1.4.1 Setting market and regulatory foundations

Work is currently underway on green hydrogen certification, but efforts to certify biomethane need to be accelerated. Certification of renewable gases is critical to support market demand as currently end users do not have a mechanism to distinguish biomethane from natural gas or green hydrogen from grey hydrogen. Certificates which guarantee the provenance and emissions attributes of green hydrogen and biomethane, and complementary reforms to emissions reporting frameworks, will allow end users to make emissions reduction claims and support the growth of the market.

Domestic regulatory alignment with international standards is important to provide confidence in product safety and reduce costs. Contrasting biomethane standards within and outside Australia currently adds complexity and cost for prospective project developers, and current gas specifications in Australia are more stringent than in the EU. Regulations should also be harmonised across jurisdictions.

1.4.2 Stimulating production and driving down costs

Deployment incentives will have an important role in supporting Australia's green hydrogen and biomethane industries to move down technology cost curves more quickly and achieve the scale of production needed to contribute to sectoral decarbonisation pathways. Deployment incentive schemes have been widely used in Australia and internationally to support uptake of renewable energy technologies. By providing financial support to bridge the commercial viability gap between production costs and market prices, deployment incentives help to encourage investment in production capacity. This helps industries to achieve economies of scale and learning effects more quickly than would otherwise be the case. For renewable gases, this will translate to faster emissions reductions through more rapid displacement of fossil fuels in priority sectors. Lower costs for renewable gases may also provide additional options for sectors with as-yet uncertain decarbonisation pathways. The Renewable Energy Target (RET) provides a well-known example of a deployment policy which began at a modest scale and helped to drive down the cost of renewable electricity generation.

Deployment policies are also an appropriate response to developments on the international stage. Significant public policy backing for hydrogen in the US and EU means that these economies are likely to be preferred destinations for international capital, and this could lead to first-mover advantages in the international trade of hydrogen. According to some commentators, Australia runs the risk of being 'left behind' in the global hydrogen economy if there is an inadequate response to these industrial policies. For example, it has been estimated that if Australia does not respond to the IRA, exports of hydrogen could be 65% less per year by 2050 than what was expected before the IRA's introduction.[4]

In response to these drivers, the Australian Government has begun developing larger-scale deployment policy for green hydrogen. Namely, Hydrogen Headstart will provide revenue support for a small number of large-scale renewable hydrogen projects. The program will be implemented through competitive hydrogen production credit contracts, with the aim of putting Australia on course for up to a gigawatt of electrolyser capacity by 2030.[5]

Next steps should focus on setting clear aspirational targets for renewable gases, developing suitable deployment incentives for biomethane, and identifying options to build on the Hydrogen Headstart program over the medium term. Deployment measures should be guided by clear aspirational targets for the production of renewable gases by 2030 and 2035. Such targets will set the level of ambition for deployment policy design and provide a clear signal to investors on the role of renewable gases in Australia's decarbonisation journey. Once targets are established, policymakers should evaluate options to build on Hydrogen Headstart and establish similar incentives for biomethane (see Section 1.5 for discussion of options).

1.4.3 Addressing social license and spill over effects

As renewable gas uptake accelerates, it will be important to actively manage the potential for spill-over effects and social license issues. Strategic planning and public awareness initiatives should be prioritised to complement renewable gas deployment policies.

The development of a national bioenergy strategy is recommended, as policy settings for biomethane should be considered in the context of the broader role for bioenergy in Australia's journey to net zero. Other uses of biomass (such as liquid biofuels and electricity generation from biomass) will mean that there is likely to be competition for biomass resources. It will also be necessary to mitigate any risks arising from expanded bioenergy production, including managing land-use competition and impacts. On the other hand, bioenergy holds potential to add value to waste and by-products, providing new sources of regional jobs. The development of a national bioenergy strategy with realistic targets will help to address these potential challenges and opportunities while also providing a clear signal to industry.

Renewable gas policies need to be accompanied with appropriate public communication to build awareness and understanding. Public awareness of renewable gases and their role in the energy transition is limited, and this could lead to social license challenges as deployment policies are progressed.

1.5 Design options for deployment policy

Having identified deployment policy as a priority, we assessed policy options for their suitability to stimulate production over the next five to 10 years. After this initial stage, appropriate policy options would need to be reassessed based on the cost reductions that have been achieved and new information available on the most viable net zero pathways for different sectors and uses.

We shortlisted three options, each of which draw from models that have been widely used in energy markets:

- **A Renewable Gas Certificate (RGC) scheme.** Under an RGC scheme there is an annual renewable gas production target calculated from an estimated proportion of forecast gas consumption. This target could be different for hydrogen and biomethane. Participating producing

[4] Deloitte. deloitte-au-australias-hydrogen-tipping-point-report-updated-280223.pdf. Last updated 28 February 2023.

[5] DCCEEW. Hydrogen Headstart program - DCCEEW. Last updated 6 July 2023.

entities would receive a Renewable Gas Certificate for each 1 TJ of renewable gas supplied to the market. To reach the target, liable entities (large users and gas retailers) are required to purchase a proportion of RGCs in line with their forecasted share of total natural gas consumption.

- **A Contract for Difference (CfD), where the shortfall between the cost to produce renewable gas and the price it can be sold for is covered by the government for an established period of time.** Contracts for difference incentivise renewable gas production by providing price certainty to developers. Some CfD designs include upside risk sharing, where the government will receive the difference between the strike price and market price when the market price is higher.
- **A Feed in Tariff (FiT), where renewable gas producers receive a fixed amount of revenue per unit of renewable gas injected in the network for an established period of time.** FiT's are typically paid as a fixed tariff rate on the volume of renewable gas supplied to the network. The aim of a FiT is to incentivise production by providing a premium above fossil fuel competitors for renewable gases.

The three policy options above are not necessarily mutually exclusive, but rather provide an illustration of the trade-offs between policy design choices. For example, an RGC scheme provides certainty on production quantities but with greater risk on the total policy cost. A CfD provides a cap on the policy cost, but greater uncertainty on the production quantity that will be achieved. In practice, policies can be designed to combine elements across the three instrument types or multiple instruments can be implemented in parallel (e.g. an RGC scheme with CfD contracts for certificates).

For any policy instrument, an important first step is to set ambitious but realistic targets for renewable gas production. While target-setting is an inherent feature of an RGC scheme, CfD and FiT designs should also be calibrated against quantitative production targets that align to the desired policy ambition (which in turn reflects factors such as scale of deployment, availability and cost). The key differences between the three types of instruments are in the mechanisms through which they aim to meet a given production target, and in how they allocate the associated costs and risks.

1.5.1 Qualitative assessment

We qualitatively assessed the three policy instruments against six key criteria, outlined below.

Assessment Criteria	
Capacity to deliver material cost reductions in future	Capacity to cost-effectively reduce greenhouse gas (GHG) emissions and contribute to net-zero pathways
User preferences, social license and avoiding disruptive change	Market co-ordination and managing spill-overs
Allocation of costs	Allocation of risk

Each instrument has their advantages and disadvantages, which may change at different points in time. Importantly they have different allocations of costs and risks that will influence the choice of instrument as circumstances change. As conventionally implemented an RGC scheme will be borne by consumers in the market, via consumer charges. CfDs and FiTs are usually budget-funded, though they can be recovered in other ways. Risks around cost, technology and supply are also allocated differently. An RGC scheme is more administratively complex and would require a longer lead time to implementation than a budget-funded CfD or FiT.

Based on our analysis, an attractive approach at the current juncture would be to combine the strengths of a FiT with elements of a CfD design, as under the proposed Hydrogen Headstart scheme. A conventional CfD design provides flexibility and breadth in terms of eligible sectors and uses, but government bears price risk and uncertainty on the total scheme cost (given that this is dependent on the difference between the strike price and prevailing market price). The proposed Hydrogen Headstart design provides a sensible middle ground. It provides investor certainty in the form of a fixed production credit contract, which also provides certainty to government on fiscal cost. In addition, the government has proposed other risk sharing elements, including that the government can share in upside price risks should they eventuate. It can be developed relatively quickly as it is implemented via contracts rather than legislation, and allows for close attention to potential spill-overs from recipient projects.

An RGC scheme has advantages as a market-based, emitter-pays mechanism, and could be considered in the medium term. An RGC scheme could be a highly effective instrument for stimulating deployment at scale and cost reductions, in a similar fashion to the RET for renewable electricity. Market participants bear some cost and price risk, along with consumers. However, renewable gas technologies and supply chains in Australia are arguably at an earlier stage of development than was the case at the inception of the RET. Both markets are also likely to be considerably less liquid, with fewer suppliers in earlier years due to the importance of scale (with hydrogen) and the need to develop limited biomass/waste supplies (for biomethane). In the short-term, building off the Hydrogen Headstart approach would provide a lower-risk option for managing price risks and unforeseen spill-overs, while also mobilising support more quickly.

Focusing first on CfD-style policy instruments can be considered as a transitionary approach to provide timely industry support and manage risk, while other instruments may be more appropriate in the medium term as the market matures. An RGC scheme can be considered for implementation, based on the information and lessons gathered from Hydrogen Headstart and an equivalent CfD scheme for biomethane. A FiT approach could also be considered for biomethane once more information is available on supply points and prices. We suggest a review point in around five years' time would be the appropriate juncture to consider whether these more structured deployment approaches were warranted, and to consider the scale of aspirational targets for the mid-2030s and beyond.

1.5.2 Possible policy settings and modelling results

Our quantitative analysis of possible deployment policy settings assessed three possible levels of ambition compared to the status quo, with the upper bound aligned to AEMO's 'Diverse Step Change' scenario assumptions for renewable gas blending. For each level of ambition, we defined separate targets for green hydrogen and biomethane given their different characteristics and different potential contribution to decarbonisation pathways. The options were:

- *Status quo*: business as usual to 2030, including Hydrogen Headstart projects, and small amounts of biomethane used by industry.
- *Low ambition:* target 2% of domestic gas consumption for hydrogen by volume, 0.7% by energy by 2030 (equivalent to increasing Hydrogen Headstart by 50%), and 0.5% biomethane by 2030.
- *Medium ambition:* midway option between status quo and AEMO GSOO scenario. 5% of domestic gas consumption hydrogen by volume, 1.7% by energy by 2030, and 1.2% biomethane by 2030 (3% in distribution network, 1% for gas power generation (GPG) and large industrial).
- *High ambition:* 10% of domestic gas consumption hydrogen by volume, 3% by energy by 2030, and 2.7% biomethane by 2030 (7.5% in distribution network, 2% for GPG and large industrial). This ambition aligns with AEMO 2023 GSOO Diverse Step Change (1.8 degrees) scenario for distribution networks.

We then assessed the cost, production volumes and emissions reductions associated with each level of ambition. Based on these targets and the assumed additional cost per GJ to produce biomethane and hydrogen compared to natural gas, the total cost until 2030 in addition to the status quo for the *low ambition* scenario is $370M, $1.87B for the *medium ambition* scenario and $4.0B for the *high ambition* scenario. The *high ambition* scenario generates 197 PJ of renewable gas until 2030 (60 PJ in 2030) and would lead to a cumulative emissions reduction of 10 million tonnes by 2030. This equates to an average abatement cost of $285 and $739 per tonne for biomethane and hydrogen respectively. Comparing this to the RET eight years after its inception[6], abatement costs ranged from $30 to $290 per tonne (in 2011 dollars). The overall cost of the RET was around $300M-$500M per year (or $2.1B-$3.5B over seven years equivalent) and CO2 emissions abated were estimated to be between 4 and 9 million tonnes.

While the more ambitious options involve greater costs now, they may also lead to greater benefits in the 2030s. This is because learning and scale effects would likely be higher, leading to price reductions for renewable gas production, which would in turn trigger greater uptake. As a comparison, when the RET was introduced in 2001, renewables made up 7.7% of electricity

[6] RET How it works and what it costs November 2013.docx (climatechangeauthority.gov.au)

generation in Australia, and 20 years later it was 26.7% of the generation mix,[7] thanks in significant part to the investments stimulated by the RET and the reductions in renewables technology costs that the scheme helped to drive in the Australian context. In the case of renewable gas, the potential extent of future cost reductions remains uncertain and may also be affected by supply constraints as more ambitious production targets place upward pressure on input prices.

We then compared two illustrative policy instruments for achieving these levels of ambition, and assessed the implications for the allocation of costs. We compared Option One: RGC schemes for both biomethane and hydrogen, and Option Two: a CfD-style approach involving an expansion of Hydrogen Headstart and the creation of an equivalent 'Biomethane Booster' for biomethane. These options were chosen for illustrative purposes, to compare contrasting approaches to cost and risk allocation. In practice, policy instruments may be designed with cost and risk sharing arrangements that combine elements of both designs. For Option One (RGC), the cost to fund the scheme would sit with retailers and large gas users. If costs were passed onto households and businesses for the proportion of renewable gas that goes to the distribution network, the cost per household/commercial connection per year in 2030 would be $2 for the low ambition scenario, $33 in the medium and $68 in the high ambition scenario. This is comparable to the early consumer costs of the RET, which have been estimated in the range of $50-$100.[8] If Option Two (CfDs) were taken up, and none of the costs passed to consumers, government would fund the costs to 2030.

The choice of instrument also depends on whether price certainty or volume certainty is preferred, and who (retailers/major gas users or government) should be responsible for bearing cost and market risks. For Option One (RGC), the impact of changes in production cost would be borne by producers, retailers and gas users, and there would be no or limited change to renewable gas volumes. Our analysis shows an increase of 20% on the assumed additional cost to produce renewable gas over natural gas could increase costs to retail consumers and large gas users by $180M - $910M under Option 1, depending on the ambition. For Option Two (CfDs), costs would be borne by government the contract amount would be set, with volumes of renewable gas more uncertain. For Option Two, producers are at risk of losing revenue if the cost to produce renewable gas is higher than assumed under the production credit contract. In contrast, if production costs are more favourable than anticipated, the surplus would be shared between producers and government.

1.6 Our recommended path forward

We assess that a contract-for-difference policy instrument is most suited to the immediate need to accelerate deployment of renewable gases, while an RGC scheme can be established in the medium term as the market matures. A CfD approach will provide an opportunity to share in the several risks around technology cost curves and natural gas pricing, while also allowing the range of positive spill-overs to be explored, and potential risks managed. A CfD approach can be established quickly and help provide the initial steps towards incentivising renewable gas production, before an RGC scheme is considered in the medium term. A FiT could also be considered as a medium-term option for biomethane.

Such a policy approach can occur within the framework of ambitious but achievable targets for each renewable gas. Targets can assist industry planning and guide further policy development. We consider though that this target should be separated from the RGC scheme policy instrument itself given the characteristics of this market, and should be defined separately for green hydrogen and biomethane.

Hydrogen Headstart establishes a CfD-style framework for green hydrogen, and an analogous approach should be developed for biomethane. For Hydrogen Headstart, the focus for potential extensions should be on expanding the range of use cases and supply chain options for bringing this renewable gas to market. A similar 'Biomethane Booster' program, scaled in such a way as to provide

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[7] KPMG calculations based on data from Australian electricity generation | energy.gov.au, accessed September 2023

[8] The Centre for International Economics. The Renewable Energy Target: How it works and what it costs Last updated November 2013. On page 14, the report cites consumer cost estimates for 2012/13 from ACIL Tasman ($50, real 2011 dollars), IPART ($102, nominal) and the Climate Change Authority ($68, nominal).

meaningful testing of different feedstock and supply chain options, would address the main gap in the current policy framework.

The below roadmap sets out key recommended actions over the next five years to establish market foundations and drive initial deployment, while gaining more understanding of spill-overs. The initial focus is on setting market foundations and getting production mobilised quickly through CfD contracts, with early actions remaining open to a broad range of use cases and sectors. By the late 2020s, policymakers would turn attention to setting more ambitious 2035 targets and establishing appropriate instruments for this scale up, such as an RGC scheme (or possibly a FiT for biomethane). At that stage, policymakers can also consider the implications of new information on technology costs and sectoral decarbonisation pathways. This could lead to a refinement in the sectoral focus of deployment policies, and/or new focus areas for R&D policy, e.g. to ensure appropriate efforts to develop hydrogen appliances for the most prospective end use cases. A core principle of our proposed roadmap is continuous iteration, with refinements to ambition, sectoral focus and preferred policy instruments over time based on experience, market maturity and new information.

A Five-Year Roadmap for Policymakers

Phase		Priority Actions	Timeline
1	**Next 9 months**	• Accelerate timeline for biomethane inclusion in GOO • Ensure that CCA's 2023 NGER review considers issues around the recognition by facilities of renewable gas contracting and use, including in the case of blended gas from networks or other shared infrastructure. • Complete review of National Hydrogen Strategy • Develop a high level National Bioenergy Strategy to inform the development of sectoral decarbonisation pathways. • As part of these strategies identify any gaps in technical and market regulation, and user information, on renewable gases and processes to address these going forward	Sep - June 2024
2	**Next year**	• Confirm 2030 aspirational targets for green hydrogen and biomethane • Award contracts for first round of Hydrogen Headstart • Allocate funding for a Biomethane Booster deployment policy in the 2024 budget. Complete program design by end of 2024 • Based on first tender, consider allocating additional funding for a second round of Hydrogen Headstart for the FY25 fiscal year, with the intent of broadening the use cases funded • GOO scheme legislated, covering both green hydrogen (and derivatives) and biomethane • Ensure that existing R&D funding mechanisms (e.g. ARENA) fund a portfolio of both green hydrogen and biomethane demonstration pilots, to inform a wide range of use cases • Ensure any market and technical regulatory issues addressed to ensure sector readiness for wider deployment	June - Dec 2024
3	**Next 2 years**	• GOO scheme is fully operational • Round 1 Hydrogen Headstart projects under development • Round 1 Biomethane Booster projects under development	2025
4	**Next 3 years**	• Round 1 Hydrogen Headstart projects begin production by end of 2026	2026

	Phase	Priority Actions	Timeline
		• Round 1 Biomethane Booster projects begin production by end of 2026	
5	**Next 5 years**	• Take stock of information learned to date on costs and sectoral abatement pathways, and evolving demand occurring as part of more general policy impulses such as the Safeguard Mechanism and any renewable energy policies. Consider if ambition of 2030 aspirational targets can be increased. • Refresh National Hydrogen Strategy and National Bioenergy Strategy • Set renewable gas strategic targets for 2035 and 2040, consistent with latest national targets for 2035 and 2040 emissions reductions. Based on the lessons learned so far and the evolution of costs, there could be shifts in sectoral focus and overall ambition • Ensure that R&D program complements the focus of these strategic targets. For example, if there is increased emphasis on network blending of green hydrogen, then R&D efforts for hydrogen appliances would need to be prioritised, and potentially deployment incentives • Consider a market based Renewable Gas Certificate scheme for the next phase of deployment, building from momentum of the early CfD programs. A FiT could also be considered for biomethane	2027-2028