14 May 2024

Submission: Climate Change Authority 2024 Issues Paper

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure, connecting natural and renewable gas production to demand centres in cities and other locations across Australia. Offering a wide range of services to gas users, retailers and producers, APGA members ensure the safe and reliable delivery of 28 per cent of the end-use energy consumed in Australia and are at the forefront of Australia's renewable gas industry, helping achieve net-zero as quickly and affordably as possible.

APGA welcomes the opportunity to contribute comments to the Climate Change Authority's (CCA) 2024 issues paper. Ambitious yet achievable 2035 targets require an expansion of decarbonisation efforts into gas and liquid fuel supply chains. This will require robust customer decarbonisation analysis and APGA's prior recommendations to sector plans.

A 2035 renewable gas target (RGT) of 75 petajoules per annum (PJpa) as an achievable contribution from gas use decarbonisation to Australia's 2035 decarbonisation target.

APGA supports a net zero emission future for Australia by 2050[1]. Renewable gases represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. As set out in Gas Vision 2050[2], APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC[3], which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy to homes, businesses, and industry throughout Australia.

APGA recommends multi-vector decarbonisation analysis for gas and liquid fuel supply chains to better understand decarbonisation opportunities. For gas this means economic analysis of biomethane and hydrogen alongside electrification for gas use decarbonisation. This is demonstrated in analysis by ACIL Allen on least cost decarbonisation options for gas use (Attachment 1) which is the basis of APGA's recommended 2035 RGT of 75PJpa.[4]

Based developed upon robust analysis, APGA recommends that 2035 targets can be delivered based upon actions recommended under the sectoral decarbonisation plans. This

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[1] APGA, *Climate Statement*, available at: https://www.apga.org.au/apga-climate-statement
[2] APGA, 2020, *Gas Vision 2050*, https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[3] Future Fuels CRC: https://www.futurefuelscrc.com/
[4] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, report to APGA and ENA, available at https://apga.org.au/renewable-gas-target

includes actions in line with APGA recommendations to each Federal Government sectoral plan consultation to date, as well as recommendations APGA has prepared in advance of future sectoral plan consultations.

APGA recommendations to the Electricity and Energy Sector Plan (EESP)

APGA provided the following recommendations in its submission to Department of Climate Change, Energy, the Environment and Water (DCCEEW) consultation on the EESP (Attachment 2).

- **NGER market-based method for gas emissions accounting**. Recognising renewable gas certificates in NGER emissions accounting is critical to providing the investment signal for renewable gas production projects reaching FID in the near term. While GreenPower renewable gas certificates are being issued today, NGER does not recognise them.
- **GPG support via the Capacity Investment Scheme or analogous support mechanism**. GPG is needed to support Australia's 82% renewable electricity target. Extending the CIS to include GPG or developing a similar scheme can provide the long-term investment signals necessary to support investment in GPG capacity.
- **A national Renewable Gas Target.** Around 480PJpa of renewable gas is required to deliver least cost gas use decarbonisation by 2050[5]. Targeting the least cost pathway to net zero gas sets national gas decarbonisation ambition. Strong industrial reliance on renewable gas of at least 210PJpa in 2050 makes a national RGT no-regrets policy.
- **Contracts for Difference for renewable gas supply.** Renewable gas certification and recognition in NGER is the first step in starting a renewable gas industry today. The Hydrogen Headstart program is an excellent start but more must be done to ensure availability of large volumes of renewable gas including biomethane. Renewable gas Contract for Difference schemes could be used to cap the cost of renewable gas supply.

APGA recommendations to the Land and Agriculture Sector Plan (LASP)

APGA provided the following recommendations in its submission to Department of Agriculture, Fisheries and Forestry (DAFF) consultation on the Land and Agriculture Sector Plan (Attachment 3).

- **Reference the EESP for energy decarbonisation.** Duplicating energy decarbonisation efforts within the LASP risks misalignment with the EESP as well as unnecessary decarbonisation cost if LASP doesn't consider EESP decarbonisation of fuel supply.
- **Decarbonising farming practices and on-farm fuel use.** Utilising green hydrogen to produce ammonia for fertiliser will provide immediate decarbonisation benefits for the agriculture sector. Decarbonise heavy vehicles and farm machinery using renewable liquid fuels and hydrogen fuel cells, where electrification and batteries are not desirable.
- **Enabling and accessing renewable gas and fuel supply chains**. Emplacing frameworks for developing renewable gas supply chains, such as through a RGT. Utilising existing natural gas infrastructure to access biomethane, and local generation projects to access green hydrogen.

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[5] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, report to APGA and ENA, available at https://apga.org.au/renewable-gas-target. See Attachment 1.

- **Whole-of-farm accounting.** Consider available carbon accounting methods for agriculture under the Emissions Reduction Fund and whether new or combined methods would be fit for purpose, including through proponent-led method development.

APGA recommendations relating to future Sector Plans

APGA recommendations to future industry, resources, transport and built environment sector plans are anticipated to align with similar principles applicable to all four sectors. As these recommendations have not been detailed in an APGA submission to date they are expanded upon in the Expansion on Future Sector Plan Recommendations section below.

Consider the EESP in energy decarbonisation for each sector
The EESP proposes the decarbonisation of electricity alongside the decarbonisation of gas and liquid fuel supply. Considering all three energy supply chains will decarbonise under this plan expands the options available to each transport, industry, resources and built environment sector plans. Duplicating energy decarbonisation efforts within other sector plans risks misalignment with the EESP as well as unnecessary decarbonisation cost if sector plans doesn’t consider EESP decarbonisation of fuel supply.

Australia’s diverse energy customer landscape requires tech agnostic policy
Diverse energy customers require diverse decarbonisation solutions. Energy customers understand their bespoke circumstances best, hence sector plans which enable stakeholders to pursue decarbonisation that works best for them will secure the greatest emissions reduction for lowest cost. This includes consideration of Australia’s geographic challenges in particular in transport and resources decarbonisation.

Gas and hydrogen infrastructure can support decarbonisation in each of these fields
Gas infrastructure delivers more energy at lower cost than electricity today. New gas and hydrogen infrastructure can transport and store energy for a lower cost than electricity powerlines or electricity storage. Leveraging the economic efficiency of gas infrastructure delivering renewable gases can expand decarbonisation options and reduce decarbonisation cost across the remaining sector plans.

To discuss any of the above feedback further, please contact me on +61 422 057 856 or jmccollum@apga.org.au.

Yours sincerely,

JORDAN MCCOLLUM
National Policy Manager
Australian Pipelines and Gas Association

APGA recommendation of a 2035 RGT

(See Attachment 1 for more detail)

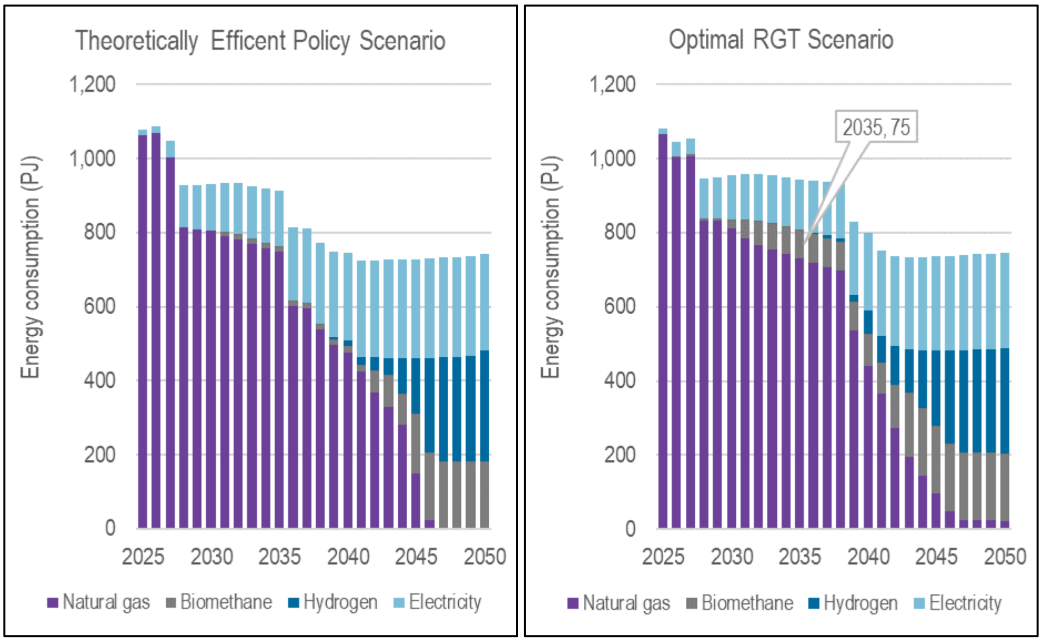
APGA commissioned ACIL Allen to undertake economic analysis of an RGT. To do so, ACIL Allen first determined the least cost pathway to gas use decarbonisation considering mature renewable gas and electrification opportunities through a perfect foresight model (referred to as the Theoretically Efficient Policy scenario). With this understood, ACIL Allen designed an Optimal RGT scenario which marginally brought forward renewable gas production. This scenario was designed to account for more realistic renewable gas supply uplift, the need for early learning to deliver cost reductions, and the imperfections in market dynamics relative to a perfect foresight model.

The fuel mix outcomes for the Theoretically Efficient Policy and Optimal RGT scenarios can be seen in the figure below. Bringing forward renewable gas production under the Optimal RGT was found to have minimal increase in overall decarbonisation cost resulting in a cost of abatement of $150 per tCO2e compared to $143 per tCO2e for the Theoretically Efficient Policy scenario. Note that the Theoretically Efficient Policy scenario is not practical to implement in Australia.

The Optimal RGT scenario was delivered with a 2035 renewable gas target of 75PJpa. APGA believes this is an achievable 2035 target noting that APGA Members and adjacent renewable gas associations identify at least half of this volume worth of renewable gas production projects already proposed today. These projects are awaiting a market-based method to recognise renewable gas emission in NGER to achieve Final Investment Decision.

APGA anticipates that once the renewable gas market is enabled through a market-based method and/or an RGT, similar to the renewable electricity market since the year 2000, the renewable gas market will develop to multiple times its current size.

Figure 1: Theoretically Efficient Policy and Optimal RGT scenario fuel mixes



Expansion on Future Sector Plan Recommendations

APGA proposes three recommendations which apply to anticipated proposals within future industry, resources, transport and built environment sector plan consultation processes.

- Consider the EESP in energy decarbonisation for each sector
- Australia's diverse energy customer landscape requires tech agnostic policy
- Gas and hydrogen infrastructure can support decarbonisation in each of these fields.

Consider the Electricity and Energy Sector Plan (EESP) in energy decarbonisation for each sector

It is important to consider the outcomes of the EESP in planning decarbonisation of other sectors. Accelerating the decarbonisation of existing gas and liquid fuel supply via alternative low carbon fuels will significantly change the range of energy decarbonisation options these sectors can access. More decarbonisation options ensure energy customers can choose the decarbonisation option that works best for them, supporting their ability to remain part of the Australian economy through their decarbonisation journey.

ACIL Allen's research on a national Renewable Gas Target (RGT) demonstrated that an Optimal RGT could secure net zero gas emissions at least cost through a combination of electrification and renewable gas supply. Without this multi-vector energy modelling, the need to decarbonise gas supply to deliver least cost decarbonisation may have been missed, leading to more challenging decarbonisation.

The EESP is considering the opportunity to decarbonise gas and liquid fuel supply. If future sector plans do not recognise this within the EESP, these sector plans risk specifying unnecessary and costly transitions away from gas and liquid fuel supply chains which are decarbonising. This risks perverse outcomes being driven by these plans including:

- Industrial and resource extraction gas users unnecessarily spending capital to transition process equipment away from gas or liquid fuel supply which decarbonises under the EESP.
- A transport sector being supported to consider hydrogen less without consideration of the EESP supporting a large scale domestic hydrogen market which would increase availability and reduce cost of hydrogen supply overall.
- Built environment gas customers unnecessarily spending capital to transition building heat and hot water away from gas supply which decarbonises under the EESP.

Australia's diverse energy landscape requires technologically-agnostic policy

Australian energy consumers know what they need best. Energy policy should be technologically-agnostic to support decarbonisation that works for energy consumers. This applies to each of the four sector plans yet to be consulted on.

In the resources sector, the Issues Paper acknowledges the opportunity to decarbonise the mining vehicle fleet by fuel switching from diesel, to electric vehicles, biodiesel or hydrogen fuel cells. Similar alternatives exist for industrial energy use where renewable gas and liquid fuel options may be the most practical decarbonisation option.

In the built environment, no two buildings are the same. Many buildings including commercial properties and high density living may be expensive, difficult or even impossible to rewire. Being able to access renewable gases as a way to decarbonise gas for energy efficient central heating and hot water in these buildings may be the most practical decarbonisation solution.

Heavy vehicles and agricultural machinery can be decarbonised using electric alternatives. But low population densities outside of Australia's cities and major freight corridors reduces the feasibility of battery electric vehicles. Farm vehicles powered by green hydrogen fuel cells[6,7] or dual fuel technologies[8] are being brought to market and will soon be available in Australia. Biomethane produced from agricultural and other feedstock can also be compressed into a renewable version of CNG, which already powers millions of passenger vehicles worldwide and can be adapted for heavy vehicles and machinery.

The common thread through each of these sectors is customer choice. Providing customers the choice to choose their lowest cost or most practical decarbonisation will support the achievability of Australia's 2035 decarbonisation target. Enabling each sector the option to decarbonise via renewable electricity, renewable gas and renewable liquid fuels ensures decarbonisation can occur faster and at lower cost and should be centre to 2035 target setting.[9]

Gas and hydrogen infrastructure can support decarbonisation in each of these fields

Existing natural gas infrastructure provides energy transport and storage at much lower cost than its alternatives today.[10] New gas and hydrogen transmission pipelines consistently cost less to deliver the same quantity of energy across the same distance in comparison to electricity transmission powerlines.[11] Gas transmission pipelines can be designed to provide 4 to 24 hours' plus worth of energy storage either for free or at low cost (typically below $20 per MWh). This applies to both blended and 100% hydrogen pipelines. Energy storage in natural gas pipelines can be hundreds of times cheaper than energy storage in grid-scale batteries or pumped hydro systems, and 2 to 36 times cheaper in hydrogen pipelines.

This becomes important when considering the challenge of transporting renewable energy over long distances – the further the distance, the cheaper pipelines become in comparison with transmission powerlines. Grid-scale renewable energy will be much more cost effective

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[6] Seneca ESG, 2023, *Kubota to roll out hydrogen-powered fuel cell tractors in 2025*, https://senecaesg.com/insights/kubota-to-roll-out-hydrogen-powered-fuel-cell-tractors-in-2025/
[7] JCB, 2023, *JCB: Building a hydrogen future*, https://www.jcb.com/en-au/campaigns/hydrogen
[8] Blue Fuel Solutions, 2023, *H_2 Dual Power*, https://h2dualpower.com/en
[9] Boston Consulting Group, 2023, *The role of gas infrastructure in Australia's energy transition*, https://apga.org.au/research-and-other-reports/the-role-of-gas-infrastructure-in-australias-energy-transition
[10] APGA, 2023, *Submission: Inquiry into the feasibility of undergrounding transmission infrastructure for renewable energy projects*, https://apga.org.au/submissions/inquiry-into-the-feasibility-of-undergrounding-transmission-infrastructure-for-renewable-energy-projects
[11] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*, https://apga.org.au/research-and-other-reports/pipelines-vs-powerlines-a-technoeconomic-analysis-in-the-australian-context

to transport from the generation source as molecules in hydrogen pipelines, than it currently is in electrons via electricity transmission powerlines.

Many of Australia's remote mining centres rely on gas for their operations. Gas pipelines were developed instead of electricity powerlines as this was the cheapest option for firmed energy supply. Mining in Mount Isa in north-west Queensland has been historically supplied energy by the Carpentaria Gas Pipeline with local renewable generation arriving recently to the region. A proposed powerline to connect Mt Isa to the NEM requires billions of dollars of Queensland Government support to be economically viable.[12] In Western Australia, the Goldfields Gas Pipeline similarly delivers gas from the Carnarvon Basin to Kalgoorlie, supplying mining estates and the Newman Power Station – a region devoid of electricity transmission.

A robust renewable gas supply chain, and in particular, a robust hydrogen supply chain, can support domestic supply of decarbonised heavy vehicle fuel. By pursuing this opportunity alongside residential, commercial and industrial hydrogen uptake, economies of scale can be leveraged in hydrogen production and infrastructure investments. Transport of green hydrogen using hydrogen pipelines would support lower cost hydrogen refuelling along Australia's major highways between major demand centres as detailed by APGA in past submissions on transport decarbonisation.[13]

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[12] APGA, 2021, *Submission: Electricity supply options for the North West Minerals Province – Consultation Regulatory Impact Statement*, https://apga.org.au/submissions/electricity-supply-options-for-the-north-west-minerals-province-consultation-regulatory-impact-statement-cris

[13] APGA, 2022, *Submission: National Electric Vehicle Strategy*, https://apga.org.au/submissions/national-electric-vehicle-strategy-consultation

Consultation questions

Climate Change Authority	APGA response
1. How should the authority take account of climate science and Australia's international obligations in considering possible emissions reductions targets for 2035?	Australia's climate targets must align with our obligations as a developed nation and leader on the international stage. To do this, Australia will need to pursue all decarbonisation avenues. The DCCEEW EESP highlights the value of decarbonising gas and liquid fuel supply in decarbonising all energy use in Australia and APGA identifies a Renewable Gas Target as a key policy to deliver gas use decarbonisation. AEMO's Integrated Systems Plan demonstrates that gas power generation is required to firm Australia's 82% renewable electricity target for many decades.
2. How should the authority weight the goals of ambition and achievability in considering possible emissions reductions targets for 2035?	An ambitious target is not worth pursuing if it is not achievable. More ambitious yet achievable targets are able to be identified through multi-vector modelling of energy decarbonisation options.
3. How can Australia further support other countries to decarbonise and develop sustainably?	The Department of Industry, Science and Resources' Future Gas Strategy identifies how Australian Liquified Natural Gas (LNG) exports are supporting decarbonisation of other jurisdictions in our region. These exports do so by providing a lower emissions alternative to coal and liquid fuels for developing nations, especially those still working to address energy poverty. Australia's LNG exports provide a foundation for a future renewable gas export market. Existing LNG facilities are able to export renewably sourced methane in the same manner as natural gas, allowing Renewable LNG to be a drop-in renewable alternative to

	LNG[14]. Future hydrogen and ammonia export industries are considered to have similar potential.
4. What technologies are important for each sector's pathway to net zero and why?	As noted in our substantive submission, renewable gases such as biomethane and hydrogen can contribute to gas customer decarbonisation. Gas use can be decarbonised through the direct substitution of renewable gas in direct consumption or gas power generation. The existing gas transmission and distribution networks and existing gas storage currently act as short-medium term energy storage facilities and can continue to do so in the future. This opportunity exists across all gas use covered by sector plans. Some gas customers have no option other than renewable gases to decarbonise. The broader the base of the renewable gas industry, the easier and more cost effective it will be to scale up to be able to support these gas customers. APGA disagrees with the perspective that renewable gas should be 'reserved' for high-value industrial users. Instead, ACIL Allen analysis indicates that some customers with decarbonisation options beyond renewable gas can still achieve lower cost decarbonisation through renewable gas uptake (Attachment 1).
5. How can governments use mandates, rules, and standards to accelerate Australia's decarbonisation? Is more planning by governments needed? If so, how should this be coordinated and how can this be done while making the transition inclusive, adaptive, and innovative?	The Australian Government should aim for a decarbonisation strategy which enables consumer choice of both individuals and investors in the technologies they use to decarbonise. As proposed in the EESP, this can be achieved by decarbonising each energy supply chain including gas and liquid fuel supply. This will ensure an inclusive transition where each customer have the opportunity to innovate and adapt upon a range of renewable energy supply options, tailoring them to their unique energy and operational needs.

[14] Osaka Gas Australia, 2023, *OGA to collaborate with Santos in e-methane production in Australia, for export to Japan and other markets*, https://www.osakagasaustralia.com.au/news/Files/20230307_pressrelease_Santos_OG_clean.pdf

6. How can governments stimulate private finance needed for the net zero transition – are there innovative instruments that could be deployed or new business models that governments could support? Is there a bigger role for governments to play in coordinating the investment needed to transition the economy?	Australian consumers are already subsidising investments in the net zero transition. Unfortunately, low carbon fuels such as renewable gases and liquid fuels have received minimal government stimulus to date. This is despite gas and liquid fuel supply accounting for over 75% of total energy demand in Australia. The Capacity Investment Scheme will support investment in renewable electricity generation and storage capacity. However, it excludes thermal generation from eligibility for tenders, even for dispatchable capacity. This is despite AEMO identifying an uplift in GPG investment as a requirement for achieving Australia's 82% renewable electricity target. Exclusion from the CIS means GPG investors will need to compete against dispatchable investments that have been able to take advantage of the scheme. APGA has commented on this issue in its submission to the Expanded Capacity Investment Scheme.[15] Some of these schemes can introduce considerable equity issues such as the Victorian Energy Upgrades program which sees Victoria's poorest households subsidising upgrades for those Victorians who can afford the expense of upgrading appliances.
7. How can governments better support markets, including carbon markets, to deliver emissions reduction outcomes?	APGA concurs with the CCA's NGER Review Recommendations from December 2023 in which it recommends recognition of robust renewable gas certification schemes within NGER emissions accounting via a market based method for scope 1 emissions produced through gas combustion. This will provide the necessary investment signals for the tens of petajoules per annum of identified renewable gas projects in Australia to achieve FID. This is required for Safeguard Mechanism Facilities to be able to use renewable gases to reduce their emissions along with the declining baselines.

[15] APGA, 2024, *Submission: Expanded Capacity Investment Scheme Design*, https://apga.org.au/submissions/expanded-capacity-investment-scheme-design

	From here, a Renewable Gas Target can set ambition in line with the least cost gas use decarbonisation pathway as identified by ACIL Allen (Attachment 1). On electricity decarbonisation, APGA recommends adding gas to the CIS or creating a similar scheme will help provide the necessary incentives for investment in GPG.
8. What further actions can be taken by governments (e.g. through public funding), the private sector and households to accelerate emissions reductions, including in relation to the deployment of technologies and access to new opportunities in the transition to net zero? What barriers stand in the way and how could they be overcome?	Robust multi-vector energy modelling is required to identify the full spectrum of gas use decarbonisation options for the private sector and households. Once identified, barriers to investment can be identified and addressed. Barriers to investment in renewable gas are policy-related and can be solved through policy initiatives that enable a gas use decarbonisation pathway through renewable gas. See answers to previous questions. The greatest barrier inhibiting renewable gas development today is the lack of a market based method for gas in NGER. Without a market based method, emissions reduction from renewable gas is unable to be commercialised as customers cannot have the emissions reduction of renewable gas purchase recognised in NGER accounting. Addressing this has already been identified by the CCA as a recommendation to government.
9. How should governments decide upon the appropriate allocation of resources towards reducing emissions, removing carbon from the atmosphere, and adapting to climate change impacts?	Determining this is an unenviable challenge made harder by a lack of multi-vector energy modelling to consider the least cost decarbonisation pathways available to each energy customer segment as per ACIL Allen analysis of gas use decarbonisation. Without such analysis it will be difficult to accurately understand the relative cost differences between carbon capture and adaptation.
10. How can governments, businesses and people, including First Nations people, help ensure the benefits and burdens of the net zero transition are equitably shared?	See answer to Q12.

11. How can governments better ensure First Nations people are empowered to play a leading role in the development and implementation of climate change policies and actions, including as they relate to the ongoing curation of the Indigenous estate?	APGA respectfully defers to First Nations communities on this topic. APGA members stand willing and open to working with First Nations communities.
12. How can Australian governments support the wellbeing of workers, communities and regions as the nation decarbonises, including in relation to cost of living, workforce and industry transition and access to low emissions technologies and services?	Australians are concerned about the cost of living. It is important that they are not further burdened by the costs of the energy transition more than is necessary. Enabling all decarbonisation options as per the EESP will ensure energy customers have access to cost-effective decarbonisation options suited to their circumstances.
13. How can governments help Australians prepare for and respond to the impacts of climate change?	As proposed within the EESP, this can be achieve by placing all energy supply chains, including the gas supply chain, on their own decarbonisation journeys through policies such as an RGT. This will enable Australia to meet more ambitious emissions reduction targets faster, with greater certainty, and while minimising cost.
14. What else should the authority be considering in its advice to government?	A 2035 target must be as achievable as it is ambitious. Only with the use of natural and renewable gas can Australia meet those targets. Supporting the decarbonisation of gas supply as proposed within the EESP and FGS should be a priority for the CCA and for Government.

ACIL ALLEN

16 February 2024

Report to APGA and ENA

Renewable Gas Target

Delivering lower cost decarbonisation for gas customers and the Australian economy

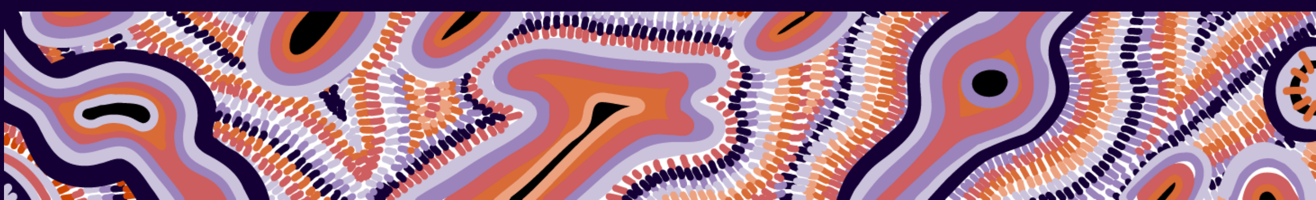
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

Key points

ACIL Allen was engaged by the Australian Pipelines and Gas Association Ltd (APGA) and Energy Networks Australia (ENA) to model the economic effects of a national Renewable Gas Target (RGT). To do this we developed a large-scale linear programming model that identifies the lowest cost way of achieving specified abatement objectives, while continuing to satisfy the underlying energy demand from today's gas using sectors.

Current policies influencing gas customer emissions are insufficient to reach net zero. Our modelling demonstrates that existing gas sector policies are insufficient to achieve net zero emissions for all gas customers – industrial, commercial and residential. It follows that additional policy action is needed to decarbonise this sector.

The most economically efficient pathway to net zero emissions for today's gas users involves a mix of renewable gas and renewable electricity. Theoretical least cost modelling shows that gas customer emissions can be reduced to net zero over the period 2025 to 2050 by switching to a fuel mix of two thirds renewable gases and one third electricity. This decarbonisation costs an average of $143/tonne CO_2-e and reflects possible outcomes under an efficient, broad-based carbon price. However, Australia's complicated history with carbon pricing means that this policy approach is not likely to be politically feasible for the foreseeable future, and so we have modelled other more practical policy options.

A Renewable Gas Target (RGT) could secure net zero gas emissions at a lower cost than a more electrification-focused approach. We modelled an Optimal RGT scenario that achieves the least cost net zero pathway while kick-starting renewable gas supply by 2030, and found that this approach would deliver an average abatement cost of $150/tonne CO_2-e compared to $165/tonne CO_2-e under a more electrification-focused approach (the Electrify Everything Possible scenario). Whole-of-economy modelling found that this saving represents an increase in Australia's gross domestic product in the order of $30 billion (in present value terms) over the transition.

Australia will need access to renewable gas as part of an efficient transition. Sensitivity analysis confirmed the significant role renewable gas is likely to play in decarbonising Australia's gas using sectors. Even when we changed assumptions to favour electrification, multiple hundreds of petajoules of renewable gas is needed, especially for feedstock use and for some very high temperature industrial processes. This result provides a high degree of confidence that policy-makers will need to implement mechanisms to develop renewable gas and ensure it is available for hard-to-electrify sectors in a timely manner. An RGT offers a viable and cost-effective approach to deliver these benefits.

Scenario	Emissions (2025-2060)	Present value of resource cost (2020-2060)	Abatement cost	Change in real economic output (GDP) relative to No Action scenario (2020-2060)	Change in GDP relative to Theoretical Efficient Policy scenario (2020-2060)
	Mt CO_2-e	$b	$/tonne CO_2-e	$b	$b
No Action	1,591	$140			
Theoretical Efficient Policy	724	$192	$143	-$121	$0
Electrify Everything Possible	729	$201	$165	-$154	-$33
Optimal RGT	722	$195	$150	-$124	-$3
Accelerated RGT	714	$202	$164	-$150	-$29

Contents

Contents

Figures

Contents

Contents

Contents

Tables

Contents

Executive summary

ACIL Allen has been engaged by the Australian Pipelines and Gas Association Ltd (APGA) and Energy Networks Australia (ENA) to model the economic effects of a national Renewable Gas Target (RGT).

Overview

Policy action is needed to decarbonise Australia's natural gas sector. In the absence of policy action, today's gas customers are projected to overwhelmingly stay on natural gas, and emissions from these users will continue to increase, producing over 1.5 Gt CO_2-e over the period 2025 to 2050. We estimate that a net zero-consistent gas sector emissions budget would be less than half of this volume of emissions, illustrating the significant abatement task facing the sector

Efficient emissions reduction is best achieved through a broad-based and technologically-neutral policy that provides equally strong incentives across all emissions sources and abatement actions. ACIL Allen has modelled a Theoretical Efficient Policy scenario that decarbonises the gas industry in line with achieving net zero by 2050 as might occur under a theoretically optimal policy such as a broad-based carbon price. Under this scenario gas customer emissions are reduced to net zero over the period 2025 to 2050, achieving cumulative abatement of 867 Mt CO_2-e at an average abatement cost of $143/tonne CO_2-e. Renewable gas contributes about two-thirds of the long-term energy needs of today's gas users, with electricity providing the remaining third.

However, Australia's complicated history with carbon pricing means that implementing an optimal policy approach consistent with the Theoretical Efficient Policy scenario is not likely to be politically feasible for the foreseeable future. Instead, other more practical policy approaches are needed to decarbonise the gas sector. The policy action required goes beyond existing gas sector emissions policies– such as the national Safeguard Mechanism for large gas users, and the Victorian and ACT bans on new residential gas connections – which are insufficient to reach net zero by 2050.

We have modelled alternate policy frameworks for a net zero consistent pathway for the gas sector, including an electrification-focused approach and a Renewable Gas Target (RGT) that supports the progressive replacement of natural gas with renewable gases, principally green hydrogen and biomethane (Box ES 1).

Our modelling shows that an RGT can reduce emissions to net zero by 2050 at a lower cost of abatement than an electrification-focused approach ($150/tonne CO_2-e under the Optimal RGT scenario compared to $165/tonne CO_2-e under the Electrify Everything Possible scenario).

When translated to the whole economy, adopting an RGT rather than an electrification-focused approach to decarbonisation of the gas sector will increase Australia's gross domestic product in the order of $30 billion (in present value terms) over the transition.

Box ES 1 What is renewable gas

Renewable gases are gaseous fuels that can largely or entirely substitute for existing uses of natural gas in today's energy system. This analysis focuses on two main types of renewable gas: biomethane (where biogas is produced through anaerobic digestion of biomass and purified to become primarily methane) and green hydrogen (hydrogen produced from electrolysis using renewable electricity).

This analysis does not consider hydrogen produced from natural gas or coal, or naturally-occuring hydrogen.

Even when decarbonisation is accelerated as under the Accelerated RGT scenario, costs are marginally lower per unit than an electrification-focused approach ($162/tonne CO_2-e, compared to $165/tonne CO_2-e).

Scenario	Emissions (2025-2060)	Present value of resource cost (2025-2060)	Abatement cost	Change in real economic output (GDP) relative to No Action (2025-2060)	Change in GDP relative to Theoretical Efficient Policy (2025-2060)
	Mt CO_2-e	$b	$/tonne CO_2-e	$b	$b
No Action	1,591	$140			
Theoretical Efficient Policy	724	$192	$143	-$121	$0
Electrify Everything Possible	729	$201	$165	-$154	-$33
Optimal RGT	722	$195	$150	-$124	-$3
Accelerated RGT	714	$202	$164	-$150	-$29

Under all scenarios, Australia will need access to renewable gas as part of an efficient transition. Even under an electrification-focused approach, renewable gas is needed for feedstock use and for some very high temperature industrial processes. Policy support is needed to develop these energy options and ensure they are available for hard-to-electrify sectors in a timely manner. Developing renewable gas will also reduce the risk of relying too heavily on electrification to decarbonise the gas sector. The transition within the electricity industry is already showing signs of slippage and cost escalation, and additional incremental demand from electrification of gas loads will only add to these pressures and make achieving renewable energy targets in electricity more difficult.

Policy-makers should support an RGT to develop a broader range of technology options and support today's gas users to choose the best option for them as cost trends become clear. This flexible approach will avoid locking in poor choices based on early trends or assumptions.

In the RGT scenarios, the modelling imposes a trajectory for renewable gas in the form of a constraint on the minimum amount of renewable gas development and consumption. It does not however model the specifics of a policy mechanism required to bring this about. Such a mechanism could take several forms including:

- a certificate-based market mechanism (arguably the most efficient) similar in nature to the Renewable Energy Target for electricity
- a direct contracting type scheme similar to the recently announced Capacity Investment Scheme or Hydrogen Headstart Program.

Irrespective of the policy mechanism to be employed, some form of policy support is likely to be needed to create the necessary investment environment for renewable gas.

Modelling the transition of gas customers to net zero

To analyse the effects of an RGT we developed a Gas Transition Model (GTM) to provide insights into potential cost pathways to decarbonise Australia's existing gas using sectors. The model uses a large-scale linear program to identify the lowest cost way of achieving specified abatement objectives, while continuing to satisfy the underlying energy demand from today's gas using sectors.

We have used the GTM to model five core scenarios:

— A **No Action scenario** in which no emissions constraint applies to the sector. This scenario is utilised solely to calculate the relative cost of abatement for the other scenarios.

— A **Theoretical Efficient Policy scenario** which imposes a gas sector emissions constraint consistent with a national pathway to net zero emissions by 2050 and allows the model to identify the lowest cost way to achieve this outcome.

— An **Electrify Everything Possible scenario**, which assumes an overall emissions constraint consistent with a national pathway to net zero emissions by 2050, but restricts uptake of renewable gas options other than for activities where electrification is not possible or proven (such as feedstock and some very high temperature processes.

— An **Optimal RGT scenario**, which translates the outcomes of the Theoretical Efficient Policy scenario into a set of renewable gas targets that the model must achieve. This scenario effectively translates the generalised emissions reduction constraint from the Theoretical Efficient Policy scenario into a specific policy mechanism that can be implemented in practice. In this scenario we also slightly accelerate the uptake of renewable gas, to reflect a more gradual and realistic ramp-up of renewable gas industry capacity.

— An **Accelerated RGT scenario**, which includes an accelerated ramp-up of the renewable gas industry to more rapidly decarbonise the stationary energy sector and de-risk the development of the renewable gas sector. This accelerated adoption of renewable gas could be desirable if policy-makers wish to reduce the risk that renewable gas adoption will be hampered by logistical constraints, recognise the potential for renewable gases to underpin emerging export industries such as green hydrogen, green ammonia or green iron, or seek to hedge against potential difficulties in achieving abatement in other sectors of the economy.

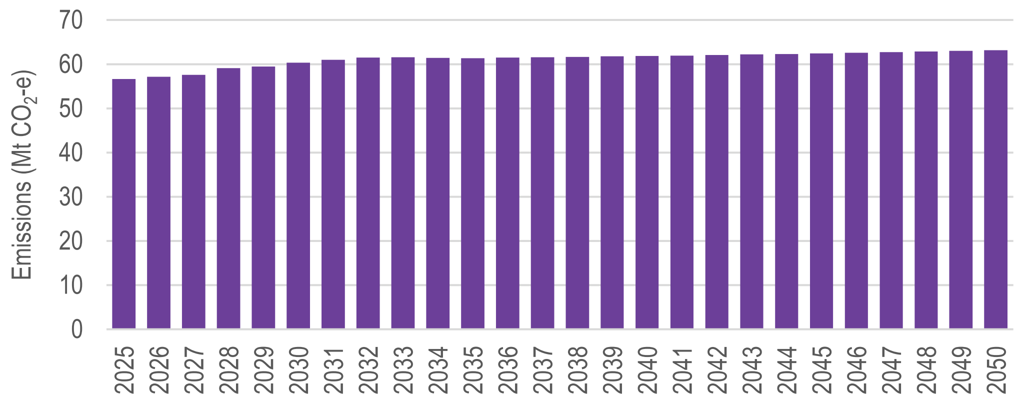
The GTM uses a range of assumptions including wholesale energy costs for electricity, natural gas, hydrogen and biomethane, and appliance capital cost, efficiency and operating life assumptions across a range of customer classes. As with any such long-term projections, there is a degree of uncertainty and the modelled results reflect the particular set of assumptions as detailed in the report. Given this uncertainty, both higher and lower cost outcomes are possible for each key variable, and different assumptions may deliver larger or smaller roles for renewable gas in the gas sector transition.

Key outcomes

Policy is needed to decarbonise the gas sector

The No Action scenario demonstrates that policy action is needed to decarbonise the sector. In the absence of policy action, today's gas customers overwhelmingly stay on natural gas, and emissions from these users continues to increase (Figure ES 1), albeit slowly, producing over 1.5 Gt CO_2-e over the period 2025 to 2050 inclusive. This cumulative volume of emissions is more than double the volume of the gas sector emissions budget we model as being consistent with achieving net zero emissions by 2050.

Figure ES 1 No Action scenario emissions (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

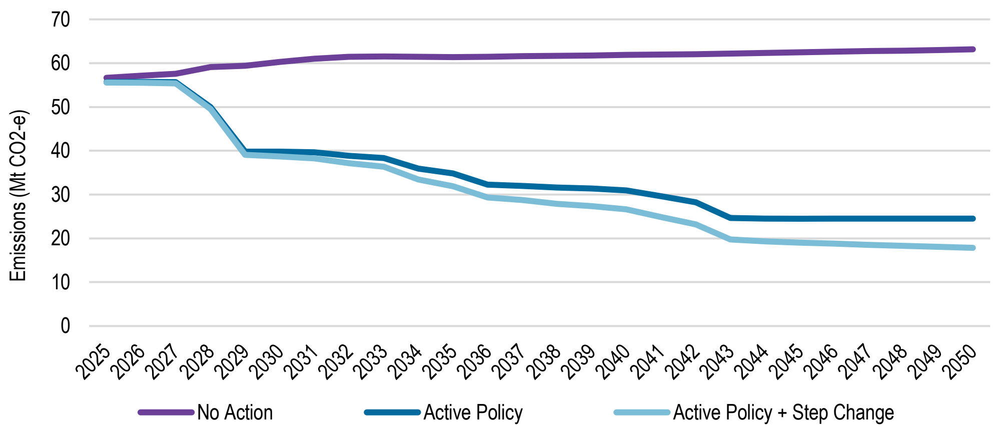
To further understand likely emissions outcomes under current policy, we also modelled sensitivities to capture the effect of current and potential policies:

— an Active Policy sensitivity that includes the effects of the national Safeguard Mechanism for large gas users, and the Victorian and ACT bans on new residential gas connections

— an Active Policy + Step Change sensitivity that incorporates the policies above as well as further residential and commercial sector electrification, consistent with the levels assumed under AEMO's Step Change scenario in the 2023 Gas Statement of Opportunities.

While emissions do reduce under these sensitivities, the modelled policies are not sufficient to achieve net zero by 2050. The Active Policy sensitivity results in emissions leveling off at around 24 Mt CO_2-e per year, while under the Active Policy + Step Change sensitivity annual emissions reduce to around 18 Mt CO_2-e over the same timeframe.

Figure ES 2 Emissions: Active Policy and Active Policy + Step Change sensitivities vs No Action scenario (Mt CO_2-e)

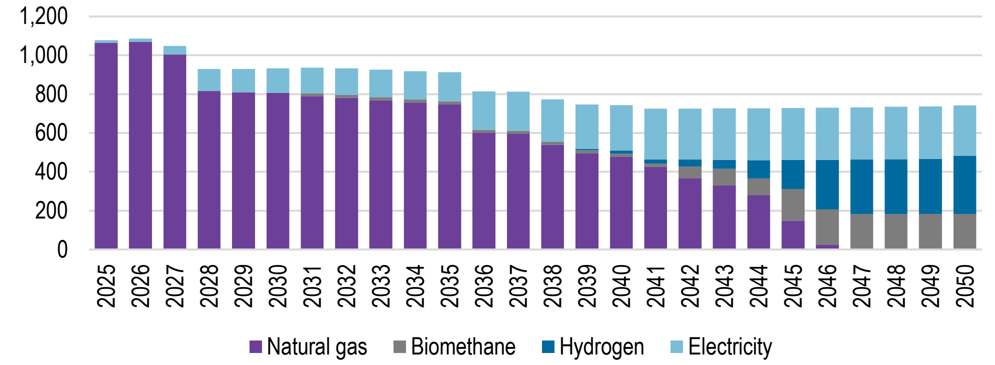


Source: ACIL Allen Gas Transition Model

Renewable gases play a key long-term role in decarbonising gas using sectors

The Theoretical Efficient Policy scenario projects a significant role for renewable gases in decarbonising Australia's gas-using sectors. While most of the early decarbonisation chosen by the model is through electrification, such as electrifying liquefaction compressors in the LNG industry, renewable gases play a larger overall role in serving the long-term energy needs of existing gas users. Approximately two-thirds of the long-run energy needs of today's gas-using sectors are met using renewable gases, and the remaining third is met with electricity (Figure ES 3).

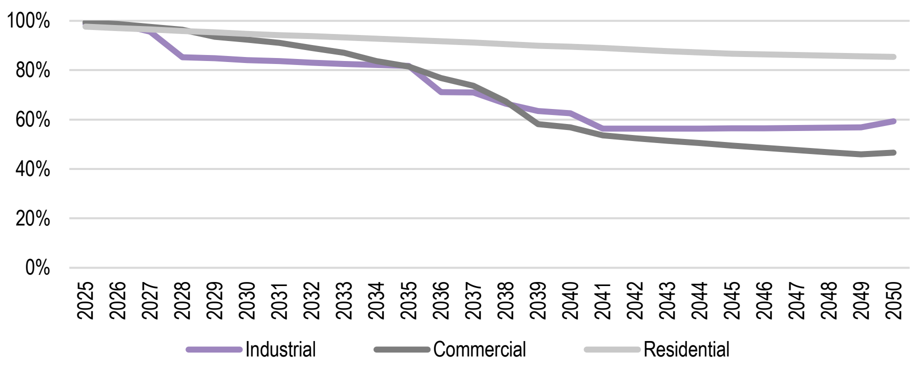
Figure ES 3 Theoretical Efficient Policy scenario fuel mix (PJ)



Source: ACIL Allen Gas Transition Model

Gaseous fuels and electricity both play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector (Figure ES 4).

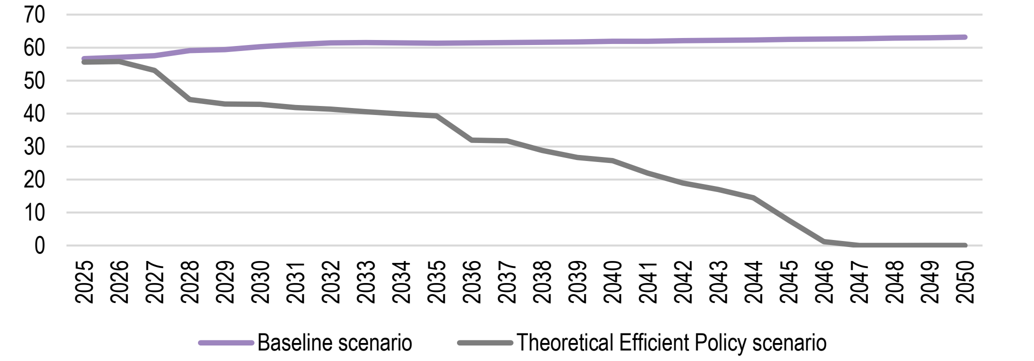
Figure ES 4 Theoretical Efficient Policy scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

The combined effect of electrification and investment into renewable gases rapidly reduces emissions from the gas sector, consistent with Australia's net zero objective (Figure ES 5).

Figure ES 5 Emissions: Theoretical Efficient Policy scenario relative to No Action scenario (Mt CO_2-e)

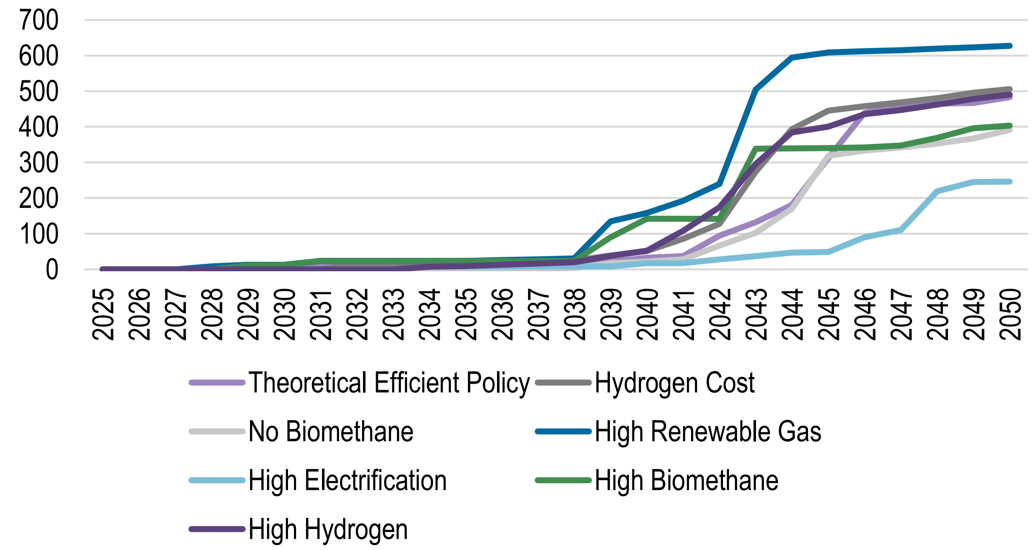


Source: ACIL Allen Gas Transition Model

The important role of renewable gas in decarbonising Australia's gas using sectors was confirmed through sensitivity analysis which varied cost assumptions from those in the Theoretical Efficient Policy scenario. This tests outcomes if technology cost trends vary from those assumed in the core modelling.

Figure ES 6 shows the level of renewable gas production under the Theoretical Efficient Policy scenario and sensitivities. This analysis shows that about 250 PJ of renewable gas is needed by 2050 if cost trends move favourably for electrification (the High Electrification sensitivity), while all other sensitivities involve significantly more renewable gas development. While the variation in results show that the precise timing and scale of renewable gas development is uncertain, policy-makers can still have a high degree of confidence that policies will be needed to support the development of a sizable renewable gas industry capable of supplying multiple hundreds of petajoules by 2050.

Figure ES 6 Renewable gas volumes (PJ): Theoretical Efficient Policy scenario compared to sensitivities



Source: ACIL Allen Gas Transition Model

While this scenario represents a decarbonisation pathway that might occur under a theoretically perfectly efficient policy such as a broad-based carbon price, and highlights that both renewable gas and electrification contribute to decarbonising today's natural gas users, Australia's complicated history with carbon pricing means that implementing policy consistent with this scenario is not likely to be politically feasible for the foreseeable future. Therefore we also examined additional scenarios that explore practical policy approaches to decarbonise the sector.

A balanced approach involving both renewable gas and electrification reduces cost

To compare the costs and benefits of potential practical policy approaches, we compared three further policy scenarios (described above):

— an Electrify Everything Possible scenario

— an Optimal RGT scenario

— an Accelerated RGT scenario.

The modelling demonstrated that restricting use of renewable gas and favouring electrification under the Electrify Everything Possible scenario increases the overall cost of the transition, relative to the use of a renewable gas target under the Optimal RGT scenario (Figure ES 7). Reflecting the lower overall cost, the Optimal RGT scenario achieves emissions at a lower per unit cost: \$150/tonne CO_2-e on average instead of \$165/tonne CO_2-e under the Electrify Everything Possible scenario.

An electrification-focused policy approach also changes the type of costs incurred during the transition. Compared to the theoretically efficient policy approach or an RGT-based approach, an electrification-focused approach requires customers to spend more capital upfront on changing appliances, in return for lower operating costs. While this is not significant within the modelling, where users do not face barriers in raising capital to change appliances, in practice some users may find it difficult to raise the capital in a timely fashion to electrify, creating an additional level of risk to the transition relative to more balanced approaches that use more renewable gas.

An important benefit of an RGT relative to an electrification-focused policy approach is that an RGT supports customers to choose either renewable gas or electrification depending on their particular circumstances. By requiring gas customers to consider the relative costs of using electricity and decarbonised gaseous fuels, an RGT creates an incentive for customers to electrify where the economics of this are suitable, while creating incentives for customers to purchase decarbonised gases when electrification is not suitable.

While the Optimal RGT scenario has slightly higher abatement cost than the Theoretical Efficient Policy scenario, it represents a practically achievable path to developing the renewable gas industry to support the decarbonisation of today's gas users. The Optimal RGT scenario brings forward renewable gas development relative to the theoretically optimal path identified in the Theoretical Efficient Policy scenario, which would have a number of real world benefits that are not captured within an optimisation modelling framework that predicts outcomes with perfect foresight. For example, bringing forward renewable gas development can:

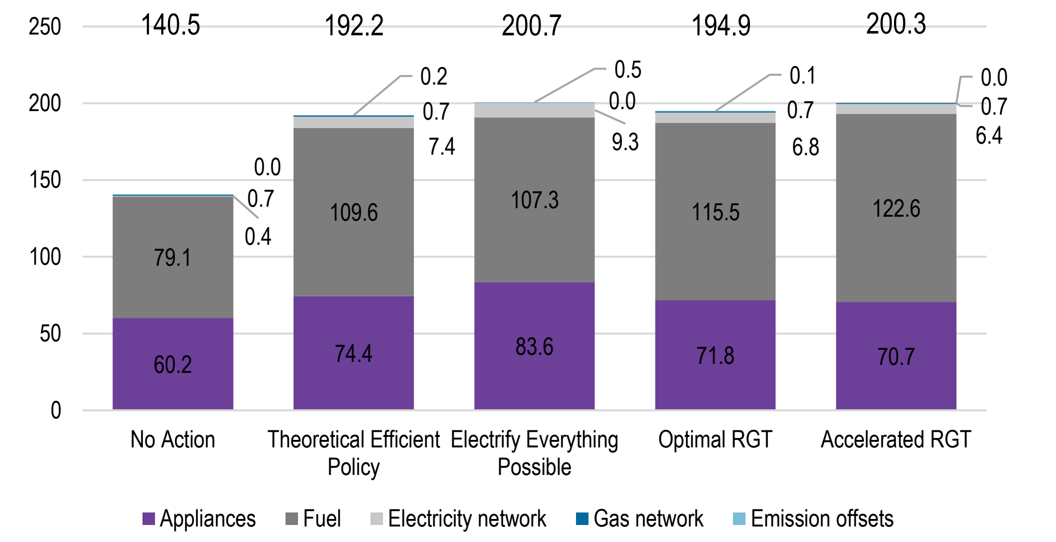
— develop industry capability and skills more gradually, rather than relying on a potentially unrealistically rapid ramp up in investment and production as is modelled in the Theoretical Efficient Policy scenario

— reduce the risk that projects will be delayed or supply chain constraints may not support extremely rapid ramping of production (as has been seen, for example, in ramping renewable electricity generation capacity in recent years).

— build confidence of gas users to choose renewable gas by demonstrating its technical feasibility and real-world economics of renewable gas will be important to, which in turn may allow users to wait for this technology to be deployed at scale rather than rushing to solutions that are more mature today, but which may prove higher cost in the long-run.

Even when decarbonisation is accelerated as under the Accelerated RGT scenario, the cost off abatement is lower than under the Electrify Everything Possible scenario ($162/tonne CO_2-e, compared to $165/tonne CO_2-e).

Figure ES 7 Present value of costs by category, 2025 to 2060: by scenario (real 2023$b)



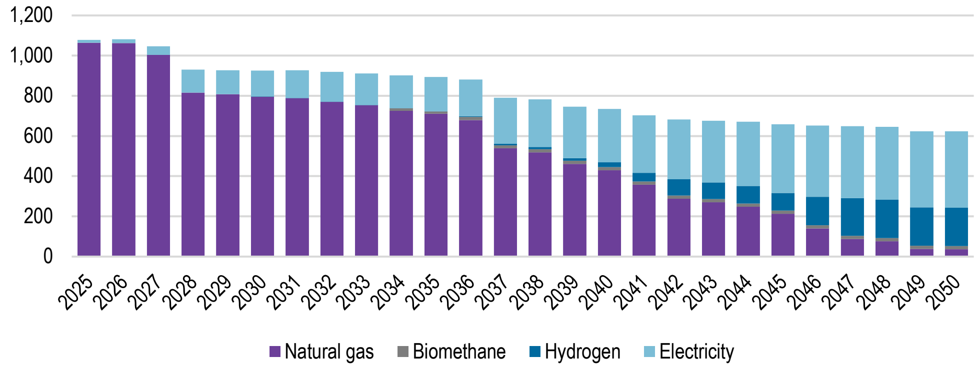
Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

Together these results highlight that failing to develop renewable gases significantly risks the energy transition. If Australia's policy framework does not sufficiently support the development of a renewable gas industry, many gas users will face higher costs and a more uncertain transition. Policy-makers should not seek to decarbonise with a 'one-size-fits-all' approach but should seek to develop both renewable gas and electrification options and allow consumers to choose the most suitable ways to decarbonise given their particular circumstances and preferences. Translating the model results to reflect the uncertainty present in the real-world through the energy transition, the modelling results will be sensitive to assumptions and the fuel and technology cost trends assumed here may not play out in practice. Given that uncertainty, keeping more technology options on the table will reduce risk in the transition – for example if one technology pathway proves more expensive or difficult than anticipated, users can adopt a different pathway.

Even under the Electrify Everything Possible scenario, the technical difficulty of electrifying some sectors results in a meaningful role for renewable gas (Figure ES 8). This indicates that policy-makers must develop a framework to develop this option to serve the needs of energy users, as many users need access to renewable gas in a net zero emissions future.

Figure ES 8 Electrify Everything Possible scenario fuel mix (PJ)



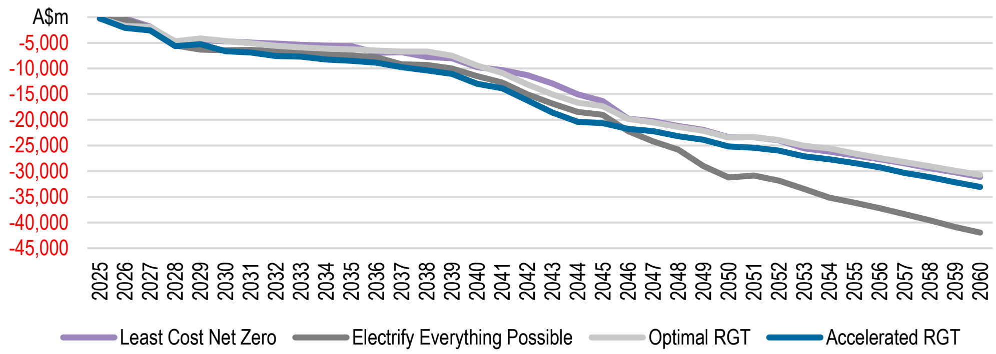
Source: ACIL Allen Gas Transition Model

Broader economic impacts

Undertaking a large-scale transition of the Australian energy system will result in a range of macroeconomic impacts beyond those analysed in the gas sector alone. Some of these will be positive (such as reductions in expenditure resulting in improving the competitiveness of Australian businesses or reducing the cost of living for residents), while some will be negative (such as increased expenditure reducing the competitiveness of Australian businesses or increasing the cost of living for residents).

There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, energy prices and volumes, and efficiency changes (Figure ES 9).

Figure ES 9 Annual change in gross domestic product under each scenario relative to the No Action scenario (real 2023$m)



Source: ACIL Allen Tasman Global modelling

In total, over the period to 2060 the present value of the reduction in Australia's GDP relative to the No Action scenario (using a 7% discount rate) is:

— –$121.1 billion under the Theoretical Efficient Policy scenario
— –$154.5 billion under the Electrify Everything Possible scenario
— –$124.2 billion under the Optimal RGT Scenario
— –$150.0 billion under the Accelerated RGT Scenario.

These results indicate that, translated to the whole economy, adopting an Optimal RGT rather than an electrification-focused approach to decarbonisation of the gas sector will save Australia in the order of $30 billion (in present value terms) over the transition.

1 Introduction

ACIL Allen has been engaged by the Australian Pipelines and Gas Association Ltd (APGA) and Energy Networks Australia (ENA) to model the economic effects of a national Renewable Gas Target (RGT).

An RGT is a policy to support the progressive replacement of natural gas with renewable gases, principally green hydrogen and biomethane. It would work in a similar way to the national Renewable Energy Target (RET) which supports investment in renewable electricity generation, and so an RGT would support investment in the renewable gas industry and allow it to mature and support the decarbonisation of Australian gas users.

To analyse the effects of an RGT we developed a Gas Transition Model (GTM) to provide insights into potential cost pathways to decarbonise Australia's existing gas using sectors. The model uses a large-scale linear program to identify the lowest cost way of achieving specified abatement objectives, while continuing to satisfy the underlying energy demand from today's gas using sectors.

We have used the GTM to model five core scenarios:

— A **No Action scenario** in which no emissions constraint applies to the sector.

— A **Theoretical Efficient Policy scenario** which imposes a gas sector emissions constraint consistent with a national pathway to net zero emissions by 2050 and allows the model to identify the lowest cost way to achieve this outcome.

— An **Electrify Everything Possible scenario**, which assumes an overall emissions constraint consistent with a national pathway to net zero emissions by 2050, but restricts uptake of renewable gas options other than for activities where electrification is not possible or proven (such as feedstock and some very high temperature processes).

— An **Optimal RGT scenario**, which translates the outcomes of the Theoretical Efficient Policy scenario into a set of renewable gas targets that the model must achieve. This scenario effectively translates the generalised emissions reduction constraint from the Theoretical Efficient Policy scenario into a specific policy mechanism that can be implemented in practice. In this scenario we also slightly accelerate the uptake of renewable gas, to reflect a more gradual and realistic ramp-up of renewable gas industry capacity.

— An **Accelerated RGT scenario**, which includes an accelerated ramp-up of the renewable gas industry to more rapidly decarbonise the stationary energy sector and de-risk the development of the renewable gas sector. This accelerated adoption of renewable gas could be desirable if policy-makers wish to reduce the risk that renewable gas adoption will be hampered by logistical constraints, recognise the potential for renewable gases to underpin emerging export industries such as green hydrogen, green ammonia or green iron, or seek to hedge against potential difficulties in achieving abatement in other sectors of the economy.

We also undertook a number of sensitivities to assess how outcomes might vary under both different policy objectives, and if fuel and technology cost assumptions vary from those used in the core modelling. We undertook:

— a Sensitivity on the No Action scenario to examine emissions outcomes under existing policies – principally the Safeguard Mechanism and the Victorian and ACT residential connection bans – but assuming no further policy effort.

— six sensitivities on the Theoretical Efficient Policy scenario that varied key assumptions such as electrical appliance capital costs, hydrogen costs, and biomethane costs and availability. These sensitivities tested how outcomes may vary if technology trends vary from those assumed in the core modelling.

— a sensitivity on the Theoretical Efficient Policy scenario that used a tighter carbon budget and achieved net zero by 2045

— a sensitivity on the Theoretical Efficient Policy scenario that varied capital cost assumptions to assess what degree of change to this assumption would be needed to mimic gas consumption trends comparable to AEMO's Step Change scenario from its Gas Statement of Opportunities modelling

— various sensitivities that explored different RGT trajectories.

Methodology and assumptions 2

ACIL Allen's approach to the engagement was to draw upon and extend an existing sectoral modelling framework developed to support the Victorian Gas Substitution Roadmap in 2021. The core component of this framework was a model which mapped a least cost pathway to decarbonising gas use for Victoria and sought to minimise societal costs given applicable targets, policies and assumptions. This least-cost pathway can then inform policy but highlighting economically efficient ways to decarbonise existing gas uses, and how sensitive these pathways are to, for example, variations and uncertainties in assumptions and changes in the speed of transition.

For the purpose of this exercise, the modelling framework used for the 2021 Victorian Gas Substitution Roadmap has also been enhanced and extended to additional gas consumer cohorts and expanded to cover the whole of Australia. The following section provides an overview of the model, while the subsequent section outlines key assumptions within the model.

Throughout this report unless otherwise noted:

— years represent financial years ending 30 June

— financial amounts are expressed in real (inflation-adjusted) terms using a 2023 dollars as a basis.

2.1 Gas Transition Model

The Gas Transition Model (GTM) was developed to provide insights into the least cost pathways to decarbonise gas consumption. The model seeks to minimise societal resource costs to achieve abatement objectives which include specific annual CO_2 emission targets for 2030 and 2050 and an overall CO_2 emissions budget over the period modelled. Resource costs consist of the present value of capital and operating costs of meeting the energy demand which would otherwise have been met by the combustion of natural gas. For this exercise we have used a discount rate of 7% to calculate present values.

The GTM is formulated as a large-scale linear program (LP) with the objective function to minimise the present value of resource costs, subject to a range of constraints. Given its large scale, the model is solved using commercial mathematical optimisation solvers.

In developing the model structure, the following design principles were applied:

— Both demand and supply side solutions are available to meet abatement targets.

— The model examines the least cost pathway from a system planning perspective. It is not a consumer choice model and does not implement Government policies to encourage take-up of certain technologies unless constrained to do so.

— The model only considers economic costs (capital expenditure and operating costs) and does not attribute a cost to continuing to use existing assets.

- Existing end-user appliances must be replaced at the assumed end of their life, but early replacement is allowed if an acceleration of appliance replacement transition is economic given any emissions or other constraints imposed.
- Blending of renewable gases into natural gas network is permitted, with biomethane and synthetic methane considered perfect substitutes for natural gas and hydrogen blending limited to 3% by energy[1] into traditional gas networks and appliances until a conversion to hydrogen capable networks and appliances occurs.
- Emissions considered include those from combustion of natural gas. It does not consider fugitive emissions. Where electrification occurs, any incremental emissions associated with additional electricity generation to serve the electrified load are accounted for within the gas sector's emissions constraints (but the baseline level of emissions from gas-fired generation is accounted for within the electricity sector, which is subject to its own emission budget).
- Usage profiles for electric appliances match the time of day and seasonal profiles from equivalent gas appliances (i.e., no time shifting of usage is assumed to occur).
- The use of CO_2 emission offsets was avoided wherever possible for the purpose of gaining insights into the cost of abatement in the natural gas sector. The model has the option to use offsets in order to meet an emissions constraint where no other options were available (in which case, failing to offer offsets would have made the linear optimisation non-feasible).

2.1.1 Model formulation

The GTM objective function is to minimise the present value of the sum of capital[2] and operating costs as follows:

$$Min \sum_{i=1}^{n} PV_{Capex(NA,H2,H2C,BM,EN,GN)} + PV_{Opex(NA,H2\ ,BM,EN,CVP)}$$

Where:

- NA = New Appliances (gas, electric and hydrogen variations)
- H2 = Hydrogen electrolysers including associated infrastructure (pipelines) and either the capital cost of dedicated solar and wind production (for 'standalone' hydrogen production), or wholesale electricity costs as an operating cost for grid-connected hydrogen production.
- H2C = End user appliance conversion to accommodate 100% Hydrogen fuel
- BM = Biomethane production plants
- EN = Electricity transmission and distribution network infrastructure to meet increased peak demands
- GN = Gas network infrastructure to serve new customers
- CVP = emission offsets / constraint violation penalties[3]

Subject to a range of constraints including:

- Emissions must be less than or equal to
  - aggregate emission budget constraints for the periods 2025 to 2030 and 2025 to 2050
  - annual emissions constraints for each year from 2050 to 2060.

[1] This is equivalent to a blend of 10% by volume. Higher blending rates may be possible.

[2] Capital cost items utilise an apportionment factor in situations where the economic life exceeds the model end period.

[3] These are used to ensure feasibility of the solution, with a post model adjustment undertaken in line with the assumed cost of offsets.

— Selected appliance switching constraints in the near-term to reflect limitations of consumer ability to switch to alternatives and available technologies (i.e., hydrogen ready appliances are not widely available at present)
— An energy balance constraint which forces all energy demand within model scope to be met each period
— All appliances which reach end-of-life (or prior if emissions constraints dictate) are replaced with an equivalent gas, electric or hydrogen variant (annual appliance stock model constraint: $Stock_y = Stock_{y-1}$ – EndofLife + New)
— Demand for appliances in new dwellings and business premises is met
— Hydrogen blending within the gas stream is limited in aggregate to 3% by energy unless a complete appliance conversion is undertaken.

2.1.2 Solution space

The GTM selects the combination of appliances and supply technologies which minimises resource costs. This can include:

— End users are broken down into representative cohorts
— End users purchasing a replacement natural gas appliance and continuing to consume natural gas
— Developing biomethane production facilities to supplement natural gas sources with a lower emissions profile
— End users switching to an electric appliance with the model accounting for increases in wholesale load-weighted electricity prices, transmission and distribution costs (where peak demand increases)
— End users switching to a hydrogen appliance where full hydrogen conversion has occurred
— Developing hydrogen supply sources, transmission and storage infrastructure to blend into the natural gas stream or supply 100% of the gas stream if full hydrogen conversion has occurred.

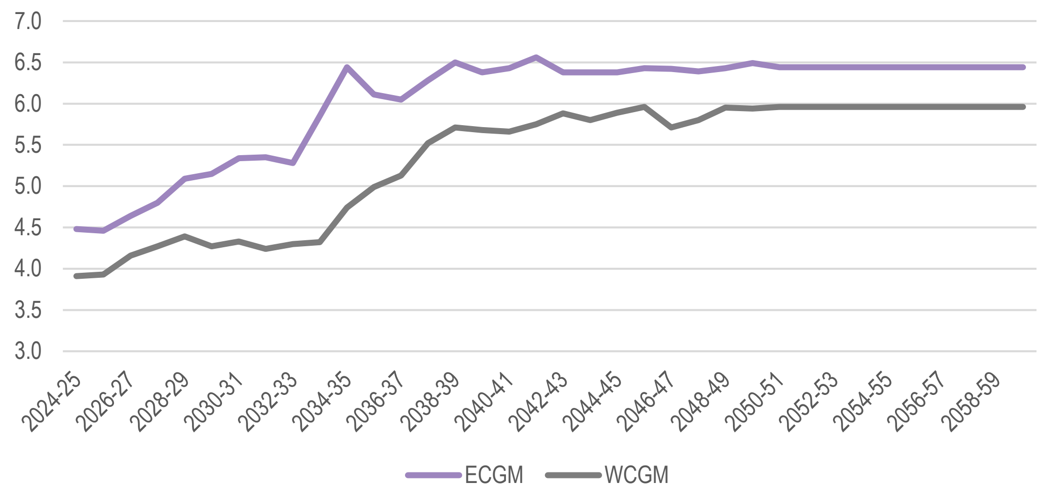
2.2 Key inputs

Natural gas prices

ACIL Allen was recently engaged by AEMO to undertake price projections to inform the Annual Inputs and Assumptions Report (IASR) and Gas Statement of Opportunity for 2024 within the East Coast Gas Market (ECGM) and Northern Territory. As a part of this work, ACIL Allen aligned key gas market assumptions within our proprietary modelling software GasMark Global (GasMark) with AEMO's assumptions. We used GasMark to generate projections of future supply demand balance and estimate wholesale gas prices based on these assumptions for the ECGM, and based on our in-house market assumptions for the west coast gas market (WCGM). For each market we examined cost and price outcomes under high and low demand cases, reflecting significant uncertainties in the future of the gas market, and used these estimates to estimate the resource cost per unit of gas production. These costs are less than wholesale gas price outcomes which include a profit margin to producers over the raw cost of extraction.

The results of these projections are presented in Figure 2.1. Further details on the methodology used to derive the wholesale gas price series used in the GTM are provided in Appendix A.

Figure 2.1 Resource cost per unit of gas production, by market ($/GJ)



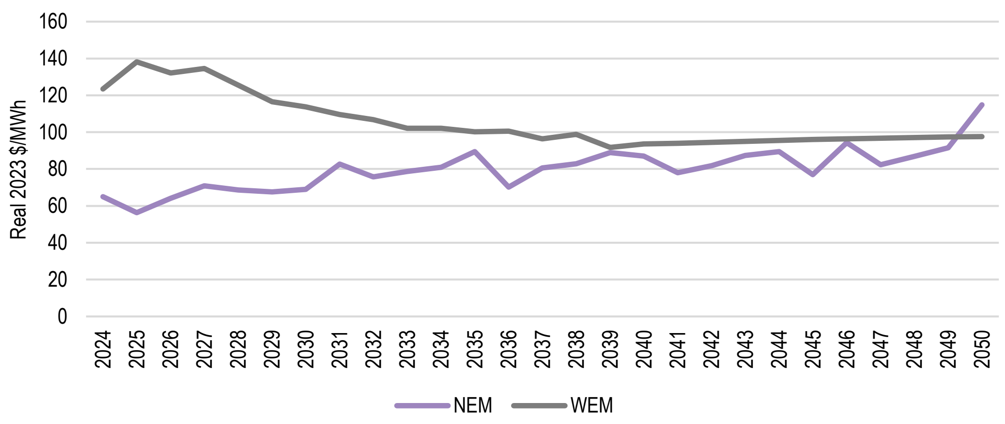
Source: ACIL Allen GasMark modelling

Wholesale electricity prices

The resource cost approach for electricity has drawn from AEMO's 2022 Integrated System Plan (ISP) modelling for the National Electricity Market (NEM). ACIL Allen has utilised the Plexos modelling platform and AEMO's published input databases to run the ISP Step Change scenario and extract load-weighted price outcomes from this least cost planning scenario.

As there is no comparable ISP dataset for Western Australia, ACIL Allen has drawn from its internal Reference case projection for the Western Australian Wholesale Electricity Market. This scenario utilised AEMO inputs for demand from the 2023 WA Electricity Statement of Opportunities (WA ESOO) report. The cost series for the WEM reflects the load-weighted price outcome from the real-time energy market plus projected reserve capacity market costs. WEM electricity costs are also applied to the North-West Interconnected System and Northern Territory.

Figure 2.2 Resource cost per unit of electricity, by market ($/MWh)



Source: ACIL Allen modelling

Further details on the methodology used to derive the wholesale electricity price series used in the GTM are provided in Appendix B.

Hydrogen production costs

ACIL Allen modelled two primary hydrogen production cost series:

— A firmed hydrogen series based on 'standalone' production, that is, dedicated solar and wind generation, electrolysers, storage and pipelines with no interaction with the wider electricity grid

— An unfirmed series based on small-scale grid-connected production, suitable for opportunistic blending into the wider natural gas stream.

The table below summarises the core assumptions used to estimate the cost components under each approach.

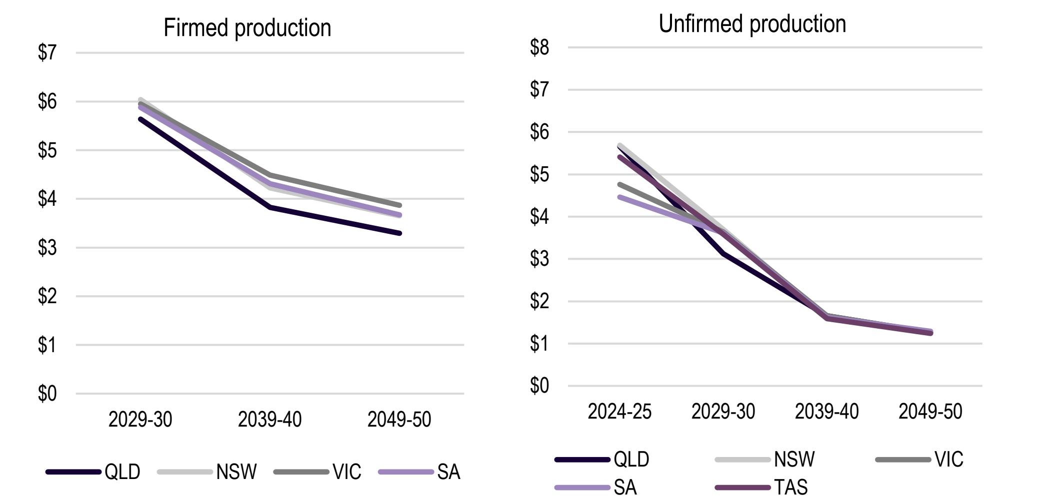
Table 2.1 Key assumptions on hydrogen production costs

Cost component	Firmed hydrogen	Unfirmed hydrogen
Electricity costs	Solar and wind costs and REZ-specific generation traces based on 2022 ISP assumptions Baseload plant power requirements costed based on ACIL Allen *PowerMark* electricity market modelling	Wholesale electricity prices from ACIL Allen *PowerMark* electricity market modelling, used for both electrolyser operation and baseload plant power requirement assumptions
Electrolyser costs	Alkaline electrolyser costs from CSIRO GenCost study (2021 study for consistency with 2022 ISP) 2022 ISP electrolyser efficiency assumption	
Hydrogen storage	Salt cavern and lined rock cavern costs based on Papadias and Ahluwalia (2021)	Not applicable
Pipeline transportation	Based on GPA Engineering (2022)	Not applicable
Baseload plant power requirements	1% of rated electrolyser capacity	2% of rated electrolyser capacity
Water costs	Aurecon assumptions for the 2022 ISP	

Source: ACIL Allen analysis based on the source cited.

Based on these assumptions we estimated the hydrogen production cost series presented in Figure 2.3.

Figure 2.3 Hydrogen production cost series (2023$/kg)



Source: ACIL Allen analysis

We note that the firmed hydrogen production cost series above is higher than some projections for this commodity, and also that it is above the widely-discussed target of $2 per kilogram, whether expressed in Australian or US dollars (we project unfirmed production costs to go below this level, but only in limited volumes). As with any such long-term projections, there is a degree of uncertainty and the modelled results reflect the particular set of assumptions used (see Table 2.1). Given this uncertainty, both higher and lower cost outcomes are possible.

Further details on the methodology used to derive the hydrogen cost series used in the GTM are provided in Appendix C.

Biomethane production costs and volumes

ACIL Allen adopted biomethane costs based on estimates published in Australia's Bioenergy Roadmap, for three core cost series:

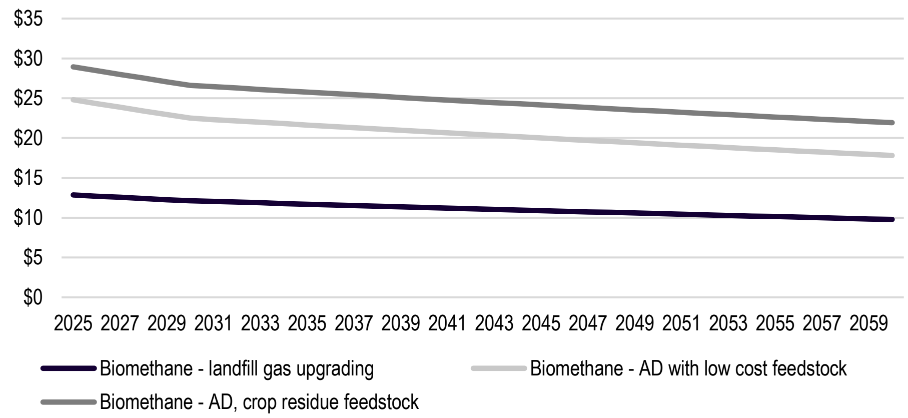
— Landfill gas upgrading, based on the landfill gas biomethane capital expenditure series from the Bioenergy Roadmap and an assumed zero feedstock cost[4]

— Anaerobic digestion based on low-cost feedstocks, based on the anaerobic digestion capital expenditure series from the Bioenergy Roadmap and an assumed zero feedstock cost (reflecting that feedstocks such as wastewater treatment sludge and food processing waste are available in concentrated amounts and do not need to be collected or purchased)

— Anaerobic digestion based on crop residue feedstocks, which also uses the Bioenergy Roadmap capital expenditure series for anaerobic digestion, and an assumed $4.1 per gigajoule cost reflecting the cost of feedstock collection and transport (also from the Bioenergy Roadmap).

Figure 2.4 presents the resulting biomethane cost series.

Figure 2.4 Biomethane cost series ($/GJ)



Source: ACIL Allen analysis of Enea and Deloitte 2021, Australia's Bioenergy Roadmap, https://arena.gov.au/knowledge-bank/australias-bioenergy-roadmap-report/, adjusted for inflation using ABS CPI data

Biomethane production of each type is limited in practice by the amount of available feedstock, the existence of competing uses for some feedstocks (such as the use of wheat stubble for animal feed) and practical limits on the timely and cost-effective collection of feedstock from various locations.

[4] Most large landfills capture methane for regulatory reasons and/or because these facilities can create ACCUs for methane destruction or create LGCs from electricity generation. The incremental cost of landfill gas capture from these sites is essentially zero. In essence, we are offering the model the chance to put the uncommercialised resource into biomethane pre-2030, and 90% of the theoretical resource post-2030.

ACIL Allen used two primary sources to estimate the available volumes of biomethane in each state:

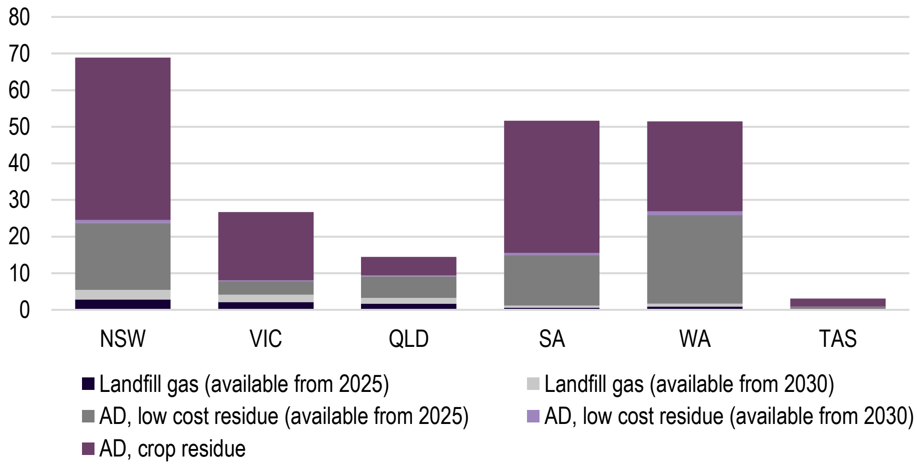
— The Bioenergy Roadmap, which includes estimates of the various types of bioenergy feedstocks by state

— Analysis by Enea Consulting for Energy Network Australia[5] that details the volume of feedstock suitable for anaerobic digestion by state.

Together these sources allowed us to identify the volume of anaerobic digestion suitable feedstock by state, separated into three core categories (landfill gas, low cost feedstock and crop residue feedstock). We made further minor adjustments to limit pre-2030 volumes to reflect existing uses of landfill gas and anaerobic digestion-derived biogas for electricity generation under the Large-scale Renewable Energy Target, which expires in 2030. The biogas associated with these existing uses are available for upgrading to biomethane from 2030.

Figure 2.5 presents our assumptions on assumed maximum biomethane production volumes based on these assumptions.

Figure 2.5 Maximum biomethane production volumes, by type and state (PJ/year)



Notes: AD = anaerobic digestion. No biomethane production is assumed in the ACT or NT.

Source: ACIL Allen analysis

Synthetic methane production costs

We modelled synthetic methane that was derived from the biogenic (and therefore carbon neutral) carbon dioxide produced as part of the biomethane upgrading process, and firmed hydrogen. We assumed that the waste carbon dioxide from biomethane upgrading would be available at zero cost, and hydrogen costs based on the firmed production costs detailed in Figure 2.3. We further assumed that the direct costs of methanation plant were $20.8 million per petajoule of annual production capacity.[6]

Based on the molecular mass ratio implied by the chemical formula for the methanation reaction, we assumed that the ratio of hydrogen input to synthetic methane output was 1-to-2 by mass, which translates to a ratio of about 1.2-to-1 by energy when adjusting for the relative energy

[5] Enea 2022, 2030 emission reduction opportunities for gas networks, https://www.energynetworks.com.au/miscellaneous/2030-emission-reduction-opportunities-for-gas-networks-by-enea-consulting-2022/.

[6] ACIL Allen analysis of Götz et al 2016, Renewable power-to-gas: a technological and economic review, *Renewable Energy* 85 (1371-1390), https://www.sciencedirect.com/science/article/pii/S0960148115301610.

densities by mass of hydrogen and methane (142 MJ/kg and 55 MJ/kg respectively). As hydrogen is the primary cost component of synthetic methane when waste carbon dioxide is available, the cost of synthetic methane will always be at least 1.2 times the cost of firmed hydrogen available in each state (see Figure 2.3), with a modest additional cost of the methanation plant itself.

The volume of synthetic methane is limited based on the volume of carbon dioxide available from the biomethane upgrading process. Based on typical carbon dioxide concentrations of landfill gas and biogas from anaerobic digestion[7], we estimated that the volume of synthetic methane was limited to 58% of the landfill gas derived biomethane, and 65% of the biomethane produced from anaerobic digestion.

Energy demand calibration by state, industry and activity

ACIL Allen used Table F of the Australian Energy Statistics[8] as the core data set for calibrating the baseline level of natural gas consumption across jurisdictions and industries. However, this data has too high a level of aggregation to suit all modelling purposes for two main reasons:

— Industry level gas use aggregates distinct activities that have different economics (such as residential cooking and heating), and so industry level data must be disaggregated to an activity level to model the underlying economics.

— State and territory level data is often obscured in Table F for confidentiality reasons, and so other sources must be used to fill gaps. At the extreme, Table F does not publish data for the ACT, which is aggregated within NSW gas demand.

We further used detailed sources such as AEMO's Gas Bulletin Boards (for both east coast and west coast markets), Australian Government published data on emissions by entities subject to the Safeguard Mechanism, gas industry statistics, gas distribution business demand forecasts and industry studies to disaggregate data to the necessary level of activity-based geographic detail.

Table 2.2 summarises the industry and activity categories at the level of disaggregation presented to the model.

Table 2.2 Modelled industry and activity categories

User type	Industry	Activity
Industrial	Agriculture, forestry and fishing	Low-temperature heat
Industrial	LNG	Compression
Industrial	Gas processing	Compression
Industrial	Gas processing	High temperature heat
Industrial	Other mining	High temperature heat
Industrial	Food, beverages and tobacco	Low-temperature heat
Industrial	Food, beverages and tobacco	High temperature heat
Industrial	Pulp, paper and printing	High temperature heat
Industrial	Petroleum and coal products	High temperature heat
Industrial	Ammonia and derivatives	Ammonia synthesis
Industrial	Ammonia and derivatives	Urea

[7] RACE for 2030, 2023, Anaerobic digestion for electricity, transport and gas https://racefor2030.com.au/wp-content/uploads/2023/04/21.B5-OA_-Final.pdf

[8] Australian Government 2022, Australian Energy Update 2022: Table F – Australian energy consumption, by state and territory, by industry and fuel, energy units, https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202022%20Table%20F_.xlsx.

User type	Industry	Activity
Industrial	Other chemicals	High temperature heat
Industrial	Glass and glass products	Glass making
Industrial	Other non-metallic minerals	Calcining
Industrial	Iron and steel	Metal reheat
Industrial	Iron and steel	High temperature heat
Industrial	Alumina	Calcining
Industrial	Alumina	Digestion
Industrial	Other non-ferrous metals	High temperature heat
Industrial	Fabricating, machinery and equipment	Metal reheat
Industrial	Other manufacturing	Low-temperature heat
Industrial	Other manufacturing	High temperature heat
Industrial	LNG	On-site power generation
Industrial	Gas distribution	Low-temperature heat
Industrial	Water supply, sewerage and drainage	Low-temperature heat
Commercial	Commercial and services	Commercial cooking
Commercial	Commercial and services	Commercial hot water
Commercial	Commercial and services	Commercial space heating
Commercial	Gas transmission	Compression
Residential	Residential - existing	Residential cooking
Residential	Residential - existing	Residential hot water
Residential	Residential - existing	Residential heating – small
Residential	Residential - existing	Residential heating – large
Residential	Residential - new	Residential cooking
Residential	Residential - new	Residential hot water
Residential	Residential - new	Residential heating – small
Residential	Residential - new	Residential heating – large

Source: ACIL Allen analysis based on the sources cited.

Estimation of appliance stock and underlying energy demand

The purpose of the model is to make choices about appliances and fuels in an economically efficient way in response to emissions constraints or other decarbonisation policies. As a result, we need to convert the observed level of gas demand into an underlying 'energy task', that could be met by, for example, natural gas, electricity or hydrogen. This is particularly important as the efficiencies of gaseous fuel and electrical appliances are very different in some cases, so the level of energy input to serve the same underlying energy task can also be very different.

Table 2.3 compares the efficiencies of gaseous fuels and electrical appliances across the various activities modelled.

Table 2.3 Comparative efficiencies of gaseous fuels and electrical appliances, by activity

Activity	Efficiency metric	Natural gas appliance	Electrical appliance	Hydrogen appliance
Low temperature heat	%	85%	300%	85%

Activity	Efficiency metric	Natural gas appliance	Electrical appliance	Hydrogen appliance
Compression	%	30%	94%	30%
High temperature heat	%	65%	85%	65%
Ammonia synthesis	TJ/ktpa (capacity)	28.6	N/A	19.2
Urea	TJ/ktpa (capacity)	16.7	N/A	9.6
Glass making	%	50%	85%	50%
Calcining	%	65%	N/A	65%
Metal reheat	%	65%	75%	65%
Digestion	%	80%	330%	80%
LNG power generation	%	36%	100%	36%
Commercial cooking	%	30%	85%	30%
Commercial hot water	%	85%	350%	85%
Commercial space heating	%	80%	300%	80%
Residential cooking	%	30%	85%	30%
Residential hot water	%	85%	95% - 350%	85%
Residential heating - small	%	80%	400%	80%
Residential heating - large	%	80%	300%	80%

Note: the lower efficiency for residential hot water is for a resistive electric water heater; the higher efficiency is for a heat pump water heater. Ammonia and urea are feedstock applications and therefore electrification is not possible. For calcining, electrification is theoretically possible (e.g. alumina calcining is being researched as part of an ARENA study) but we have no basis on which to estimate capital costs as the technology is really only theoretical at this stage.

Source: ACIL Allen analysis

We then converted the implied energy task to an appliance stock and projected this stock based on expected growth in activity in the relevant sectors. This conversion was applied differently for different sectors:

— For the industrial sector the stock was expressed as megawatts of thermal or compression load (as relevant), or as kilotonnes of annual production capacity for the ammonia synthesis and urea activities

— For the LNG industry, growth in underlying energy demand was calibrated to the Australian Government's estimates for LNG stationary energy emissions[9]

— For major gas-using sectors such as alumina, ammonia, urea, iron and steel and petroleum and coal products, underlying energy demand was held constant over the projection except for adjustments for known closures and plant openings

— For other industrial and sectors and the commercial sector, energy demand was grown in line with broader macroeconomic projections of activity in the wider sector (estimated to be 1% per year)

[9] Australian Government 2022, Australia's emissions projections 2022 https://www.dcceew.gov.au/sites/default/files/documents/australias-emissions-projections-2022.pdf

- For the residential sector:
  - Gas demand was converted into estimates of total appliance numbers based on a study of residential energy demand commissioned by the Australian Government[10]
  - The appliance stock in existing houses was reduced progressively over time to reflect housing demolitions, based on ABS housing data[11]
  - The appliance stock in new houses was grown over time to reflect ABS household projections[12], with appliance penetration calibrated base on the residential baseline study.[13]

Appliance capital costs and operating life

Capital costs are an important driver of the model's appliance and fuel choices. Given the diversity of energy tasks and appliances available to the model, these assumptions were based on a broad range of studies. For industrial activities, capital cost assumptions were based on a broad range of activity-specific studies for industrial applications. For residential activities, we primarily relied on a study undertaken for the Gas Appliance Manufacturers' Association of Australia, which detailed cooktop, hot water and heating cost assumptions across several house 'archetypes'.[14] From this study we:

- Adopted typical (rather than high or low) costs for homes from archetype 1 (large houses) for cooking, hot water and large heating activities, and typical costs from homes from archetype 3 for small heating (adjusting from the modelled two heating units to a single unit)
- Pro-rated appliance removal and rectification costs across the different appliance types for installations in existing homes, but not for new homes
- Applied the electricity connection upgrade cost to heaters in existing homes, but not to other appliances
- Applied a hydrogen appliance cost uplift consistent with that used in the study to estimate the costs of hydrogen appliances.

To further reflect the diversity of housing appliance stocks, we separated the heating task in existing homes into additional categories, based on observed appliance uptakes in the residential baseline study.[15] These categories reflected whether existing homes moving from gas to electrical heating already had one or two reverse cycle air-conditioners (which are commonly installed for cooling purposes but also offer heating). We also adjusted capital costs for new homes based on their assumed cooling choices:

- For small heaters, we assumed that a proportion of homes would choose a reverse-cycle air-conditioner for cooling purposes in any case, in which case the capital cost of adopting electric heating in one room is zero
- For large heaters, we assumed that households would either choose an evaporative cooler as well as gas ducted heating, or alternatively whole-of-house reverse-cycle air-conditioning, and

[10] EnergyConsult 2022, 2021 Residential Baseline study for Australia and New Zealand for 2000-2040, https://www.energyrating.gov.au/sites/default/files/2022-12/2021%20RBS_OutputTablesV1.9.2-AU.xlsx

[11] ABS 2022, Estimated dwelling stock, https://www.abs.gov.au/statistics/industry/building-and-construction/estimated-dwelling-stock/latest-release

[12] ABS 2019, Household and family projections, Australia, https://www.abs.gov.au/statistics/people/population/household-and-family-projections-australia/latest-release

[13] EnergyConsult 2022.

[14] Frontier Economics 2022, Cost of switching from gas to electric appliances in the home, https://gamaa.asn.au/wp-content/uploads/2022/07/Frontier-Economics-Report-GAMAA.pdf.

[15] EnergyConsult 2022.

so we added the capital cost of an evaporative cooler on to those of the gas ducted heating to ensure a like-for-like comparison.

Table 2.4 summarises the key capital cost and appliance life assumptions used in the modelling.

Table 2.4 Appliance capital cost and operating life assumptions

		Capital cost			Appliance life (years)	
Activity (by size)	Capital cost unit basis	Natural gas appliance	Electrical appliance	Hydrogen appliance	Gaseous fuels appliance	Electrical appliance
Low temperature heat	m/MW_{th}	0.5	1.3	0.65	20	15
High temperature heat (small)	m/MW_{th}	0.4	0.4	0.5	25	25
High temperature heat (medium)	m/MW_{th}	0.3	0.3	0.4	25	25
Metal reheat (small)	m/MW_{th}	0.5	1.7	0.7	20	15
Metal reheat (medium)	m/MW_{th}	0.3	1.5	0.4	20	15
Compression (medium)	$m/MW	6.4	7.8	6.4	25	25
Compression (large)	$m/MW	3.5	4.3	3.5	25	25
Glass making	m/MW_{th}	1.5	1.5	1.6	20	20
Calcining (medium)	m/MW_{th}	1.5	N/A	1.6	30	30
Calcining (large)	m/MW_{th}	1.5	N/A	1.6	30	30
Digestion	m/MW_{th}	0.3	1.7	0.4	20	15
Ammonia synthesis	$m/ktpa (capacity)	1.9	N/A	1.5	25	25
Urea	$m/ktpa (capacity)	2.7	N/A	0.8	25	25
LNG power generation	$m/MW	1.5	0.2	N/A	25	40
Commercial cooking	m/MW_{th}	0.2	0.3	0.3	20	15
Commercial hot water	m/MW_{th}	0.8	1.3	0.9	15	15
Commercial space heating	m/MW_{th}	0.5	0.8	0.5	20	15
Residential cooking - existing	$000/ appliance	2.0	2.7	2.2	20	15
Residential hot water - existing	$000/ appliance	3.2	2.9 (resistive) 5.4 (heat pump)	3.6	15	15
Residential heating - existing - no RCAC installed (small)	$000/ appliance	2.9	3.5	3.3	20	15
Residential heating - existing – 1 RCAC installed (small)	$000/ appliance	2.9	0	3.3	20	15
Residential heating - existing - no RCAC installed (large)	$000/ appliance	10.8	21.8	12.2	20	15
Residential heating - existing - 1 RCAC installed (large)	$000/ appliance	10.8	18.4	12.2	20	15
Residential heating – existing - 2 RCAC installed (large)	$000/ appliance	10.8	14.9	12.2	20	15
Residential cooking - new	$000/ appliance	3.1	2.4	3.3	20	15

Activity (by size)	Capital cost unit basis	Capital cost: Natural gas appliance	Capital cost: Electrical appliance	Capital cost: Hydrogen appliance	Appliance life (years): Gaseous fuels appliance	Appliance life (years): Electrical appliance
Residential hot water - new	$000/ appliance	4.1	2.6 (resistive) 4.8 (heat pump)	4.5	20	15
Residential heating - new - no air-conditioning (small)	$000/ appliance	3.9	3.2	2.8	20	15
Residential heating - new – with air-conditioning (small)	$000/ appliance	3.9	0	4.2	20	15
Residential heating - large - new	$000/ appliance	10.6	17.6	11.9	20	15

Note: Capital costs for natural gas appliances for large houses are inclusive of both heating and cooling appliances, as a cooling appliance is needed to provide a comparable service to the reverse-cycle air-conditioner (RCAC) costed as the electrical option. We have assumed an evaporative ducted cooling unit, following Frontier Economics 2022. For existing houses with installed RCAC units, the cost of new electrical appliances is reduced to reflect that fewer new units need to be installed. For small houses with air-conditioning, no capital cost is assumed for electrical heating as we assume that the existing unit is an RCAC. Asset lives and capital costs for electrical option for LNG power generation is for on-site network connection costs only (e.g. connection transformers) – generation capital costs are internalised within the wholesale price of electricity.

Source: ACIL Allen analysis

Carbon budgets

The overall carbon budget for gas-using sectors in scenarios with explicit decarbonisation objectives was set so as to be consistent with the Australian Government's overall emissions reduction objectives, principally:

— a 43% reduction in national emissions on 2005 levels by 2030

— net zero emissions by 2050.

Further, given that many large gas users are subject to the federal Safeguard Mechanism, we took into account the implied reduction in emissions required of those entities given the emissions budget estimated for Safeguard entities over the period to 2030.

Over the period to 2030, we estimated a stationary energy emissions trajectory that reflected a weighted average of the implied Safeguard Mechanism emissions budget to 2030 and the unconstrained stationary energy emissions projection from Australia's emissions projections, reflecting that about 70% of stationary energy gas use is subject to the Safeguard Mechanism. When we included this estimate alongside national projections of electricity, transport and other sectors' emissions, we found that this approach was consistent with the national objective of a 43% reduction by 2030.

Beyond 2030, we assumed a straight-line reduction in emissions from the estimated 2030 level to net zero by 2050.

To allow for some flexibility to achieve abatement earlier or later than implied by these trajectories, we converted the annual emissions estimates into two 'emissions budgets' that limit total emissions over a defined period. These budgets were:

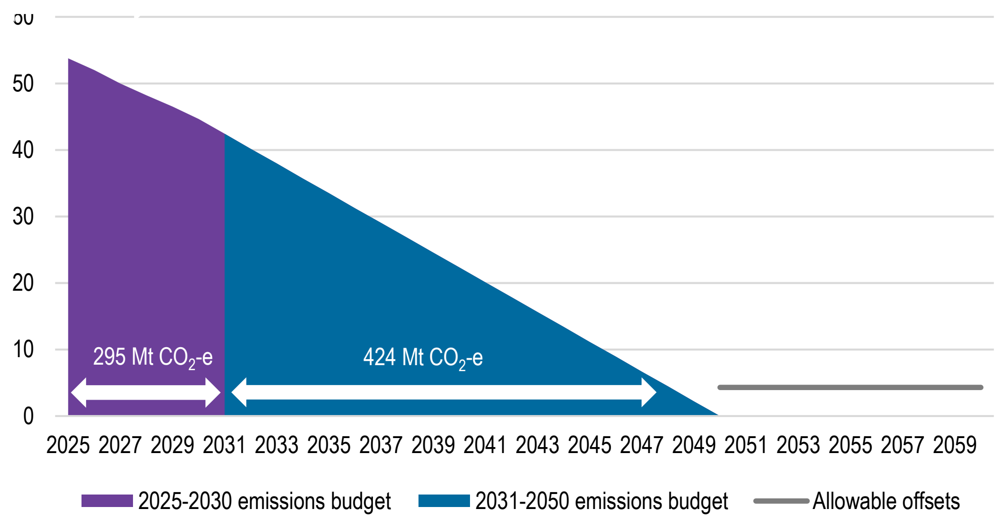
— 295 Mt CO_2-e for the period 2025 to 2030 inclusive

— 424 Mt CO_2-e for the period 2031 to 2050 inclusive (or an implied total budget of 719 Mt CO_2-e for the period 2025 to 2050).

For the period 2050 to 2060 inclusive we required the model to achieve zero net emissions in each year, while allowing the model to purchase offsets at $300/t$CO_2$-e if necessary to net out any residual emissions. To avoid over-reliance on offsets and illustrate feasible transition pathways for the gas sector, we only allow offsets to be used from 2050, and a maximum of 4.3 Mt CO_2-e of offsets can be used in each year (this number broadly reflects the gas sector's pro-rata share of current levels of negative emissions from the land use, land use change and forestry sector, and so ensures that the gas sector is not overly reliant on offsets post-2050).

Figure 2.6 illustrates how the gas sector carbon budget for this analysis was calculated, as well as the maximum level of offsets that the model will allow to be used from 2050. While the carbon budget was calculated using straight-line extrapolation over two periods (2025 to 2030 and 2030 to 2050), emissions in any given year can vary from the notional trajectory presented and the key constraints for the model are the overall limits on cumulative emissions over the periods in question.

Figure 2.6 Illustration of calculation of net zero-consistent gas sector carbon budget and maximum allowable offsets (Mt CO_2-e)



Source: ACIL Allen analysis

In all scenarios we also applied a specific emissions budget to Safeguard Mechanism entities, to reflect the operation of this existing policy. The Safeguard budget operates alongside the sector-wide carbon budgets set out above.

For some sensitivities we examined outcomes when reducing emissions to net zero by 2045 rather than 2050 and adjusted the 2025 to 2045 budget to reflect a straight-line reduction from projected 2030 levels to net zero by 2045. This methodology gave an emissions budget of 608 Mt CO_2-e for the period 2025 to 2045 inclusive. Consistent with the 2050 net zero scenarios, we held emissions at net zero in each year from 2045 for the 2045 net zero sensitivities.

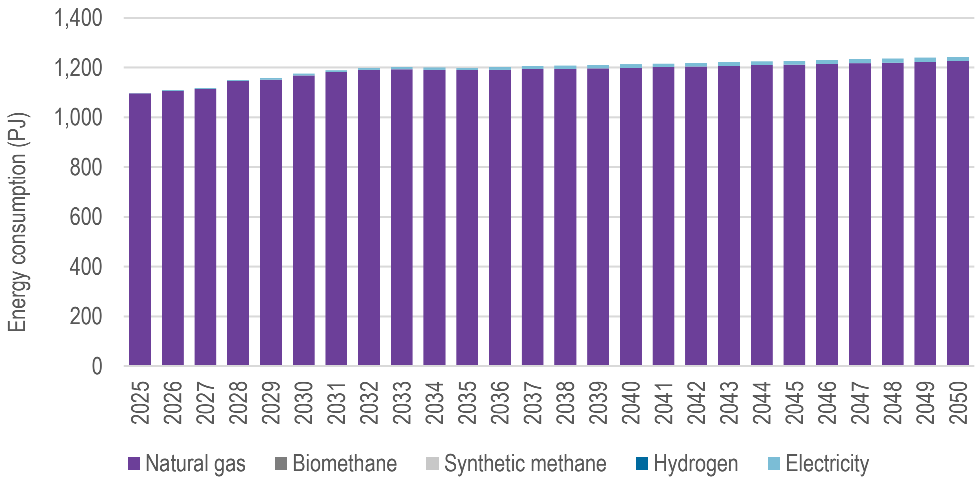
National outcomes 3

3.1 No Action scenario

The No Action scenario presents an outlook for the gas sector in the absence of any emission constraints. It is not a meaningful policy scenario as it clearly fails to achieve the common objectives of federal, state and territory governments to reach net zero emissions by 2050, and so we do not present detailed results for this scenario. Rather, the No Action scenario is used to calibrate emissions and economic outcomes in the model, for example, to calculate a cost of abatement based on the difference in emissions and costs between it and the various policy scenarios.

As the No Action scenario includes no explicit policy to reduce emissions (including implemented or announced policies such as the national Safeguard Mechanism, or the Victorian and ACT bans on new residential gas connections), natural gas use continues to grow in line with gas-using activities in the wider economy (Figure 3.1). The scenario sees small amounts of electrification where this is economic without any policy signal, primarily from cooking, water heating and some heating in new households, and heating in existing households with existing reverse-cycle air-conditioners. The total volume of electrification in the No Action is relatively small, amounting to just under 18 PJ (5 TWh) by 2050.

Figure 3.1 Fuel mix: No Action scenario (PJ)



Source: ACIL Allen Gas Transition Model

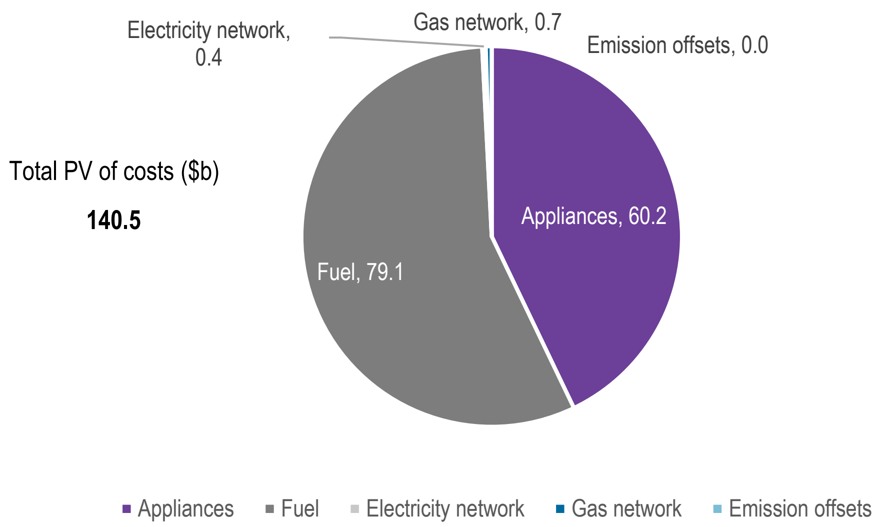
This continuing growth in gas use results in a slow but steady increase in greenhouse gas emissions from the gas sector – exceeding 60 Mt CO_2-e per year by 2030 and totalling almost 1.6 Gt CO_2-e over the period from 2025 to 2050 (Figure 3.2).

Figure 3.2 Gas sector emissions: No Action scenario (Mt CO_2-e)

Source: ACIL Allen Gas Transition Model

The present value of all costs in the No Action scenario is just over $140 billion (discounted at 7%). Figure 3.3 shows that the largest cost components are fuel costs and appliance costs, with very small costs associated with investing in electricity networks (to accommodate the small amount of electrification in this scenario) and gas networks (to connect new customers).

Figure 3.3 Present value of costs by category, 2025 to2060: No Action scenario (real 2023$b)



Note: present value calculated using a 7% discount rate

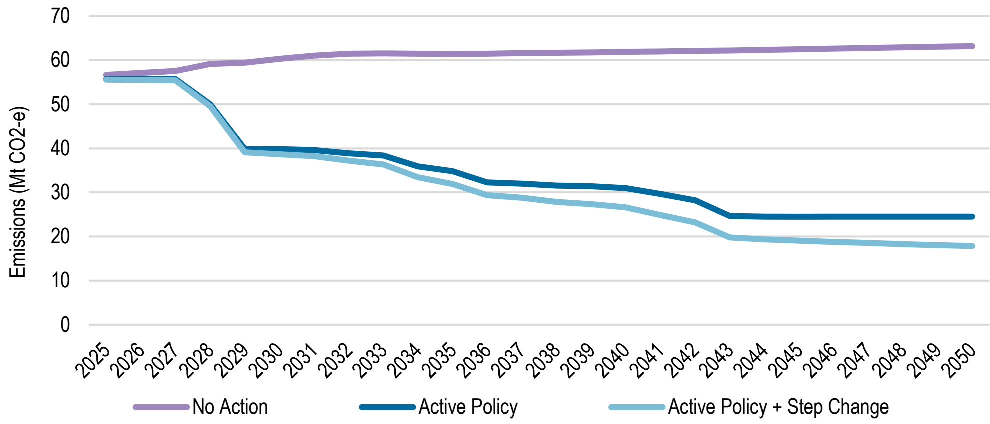
Source: ACIL Allen Gas Transition Model

Sensitivities exploring emissions outcomes under current policies

To understand the emissions trajectory of the gas sector under existing policies – principally the Safeguard Mechanism and the Victorian and ACT residential connection bans – we modelled a sensitivity that included the effects of these policies (the Active Policy sensitivity). We also explored a further sensitivity (Active Policy + Step Change) that assumed further electrification policy focused on the residential and commercial sectors that was consistent with the level of electrification in AEMO's Step Change scenario from its 2023 Gas Statement of Opportunities.

These sensitivities highlight that, while currently active policies appear sufficient to get the gas sector to a suitable abatement level for 2030, they are insufficient to achieve net zero emissions by 2050 (Figure 3.4). The Active Policy sensitivity results in emissions leveling off at around 24 Mt CO_2-e per year, while under the Active Policy + Step Change sensitivity annual emissions reduce to around 18 Mt CO_2-e over the same timeframe.

Figure 3.4 Emissions under policy sensitivities (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

These sensitivities highlight that further policy action is needed by governments to achieve net zero emissions in today's gas-using sectors.

3.2 Theoretical Efficient Policy scenario

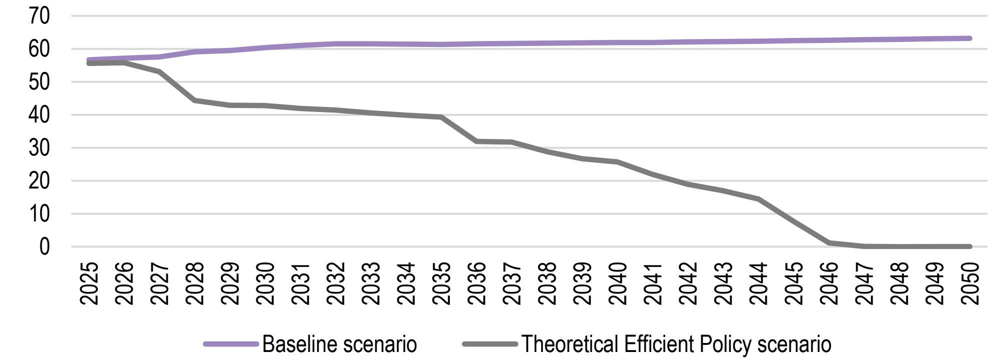
The Theoretical Efficient Policy scenario differs significantly from the No Action scenario in that it is designed to achieve net zero emissions by 2050 (consistent with government policy).

It is termed the Theoretical Efficient Policy scenario as the requirement to reduce emissions is included as an explicit constraint in the model, and the model will minimise the cost of achieving that emissions constraint in a way that reflects how a theoretical efficient policy framework such as a broad-based carbon price would work to reduce emissions. This 'policy-neutral' approach does not seek to represent individual emissions reduction policies within the model (for example, the Safeguard Mechanism or the Victorian and ACT bans on new residential gas connections), but rather seeks to give the model as much freedom as possible to identify the optimal way to reduce emissions given the input assumptions. In this way, the Theoretical Efficient Policy scenario provides a good benchmark for assessing the relative efficiency of alternative 'real world' policy approaches to achieving the same emissions outcome. While other scenarios will necessarily be higher cost than the Theoretical Efficient Policy scenario, we emphasise that the Theoretical Efficient Policy scenario is not practically achievable in Australia, given that broad-based carbon pricing is unlikely to be politically feasible in Australia in the foreseeable future. In this way, the Theoretical Efficient Policy scenario is a theoretical benchmark against which to assess potential policy approaches.

The Theoretical Efficient Policy scenario is forced to achieve emissions budgets defined for the periods 2025 to 2030 (295 Mt CO_2-e) and 2025 to 2050 (719 Mt CO_2-e), and to achieve net zero emissions in each year from 2050 (see section 2.2 for more detail on this constraint).

Figure 3.5 compares emissions in the Theoretical Efficient Policy scenario to the No Action scenario. Emissions fall to almost zero in the late 2040s. The emissions reduction trajectory includes a couple of notable step changes. The first step change is achieved by electrifying a number of LNG production facilities in 2027 and 2028, which the model sees this is a low cost means of contributing toward the 2030 emissions budget constraint. The second step down in the mid-2030s relates to further electrification of most of the remaining LNG capacity. Emissions reduce more consistently and rapidly from around 2039, reflecting significant increases in renewable gas production and use from that time, as well as ongoing electrification.

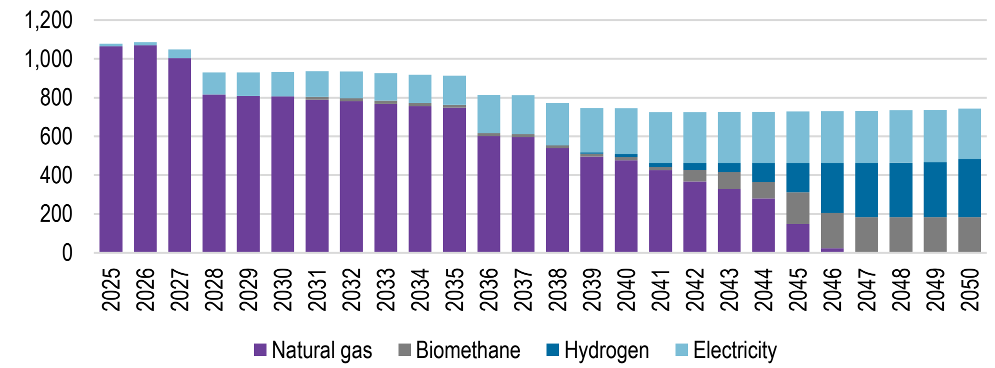
Figure 3.5 Emissions: Theoretical Efficient Policy scenario relative to No Action scenario (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

Figure 3.6 shows the mix of fuels used in the Theoretical Efficient Policy scenario. Electrification (primarily of LNG plants) plays the largest role during the 2020s and 2030s, but renewable gases (principally biomethane and hydrogen) play a greater role than electrification in the long-run, growing rapidly during the 2040s and reaching around 480 PJ by 2050 (compared to about 260 PJ from electricity).

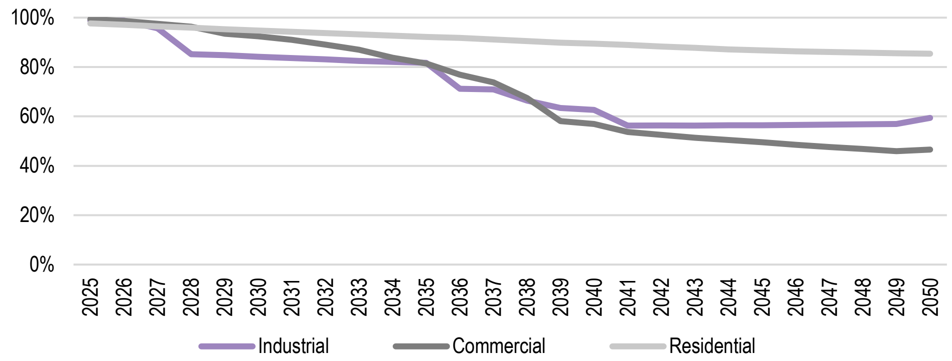
Figure 3.6 Fuel mix: Theoretical Efficient Policy scenario (PJ)



Source: ACIL Allen Gas Transition Model

Renewable gases and electrification play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector (Figure 3.7).

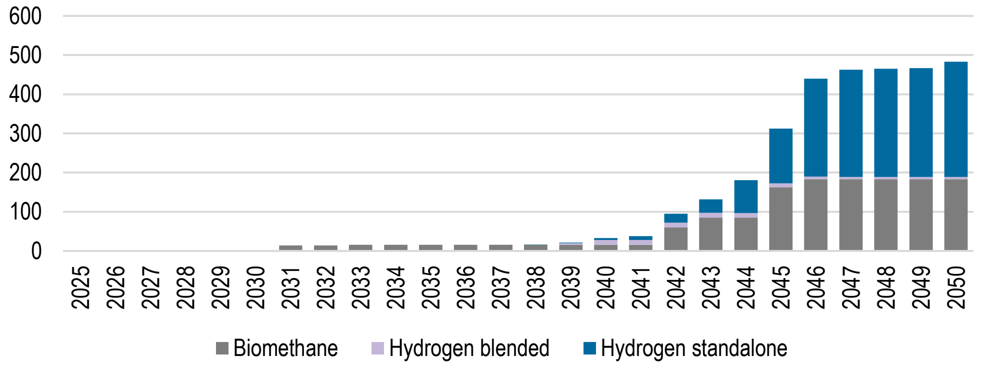
Figure 3.7 Theoretical Efficient Policy scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Figure 3.8 highlights the growing role of renewable gases as part of the fuel mix. Biomethane is initially developed from 2030 using low-cost sources such as landfill gas, before expanding to higher cost feedstocks such as crop residues, which are more scalable and allow it to ultimately supply about 180 PJ per year. Hydrogen begins to be used in ammonia production in 2036, before expanding rapidly during the 2040s to become the largest source of renewable gas supply (about 300 PJ by 2050). Some hydrogen blending into natural gas streams also occurs in fairly small volumes (up to 12 PJ per year).

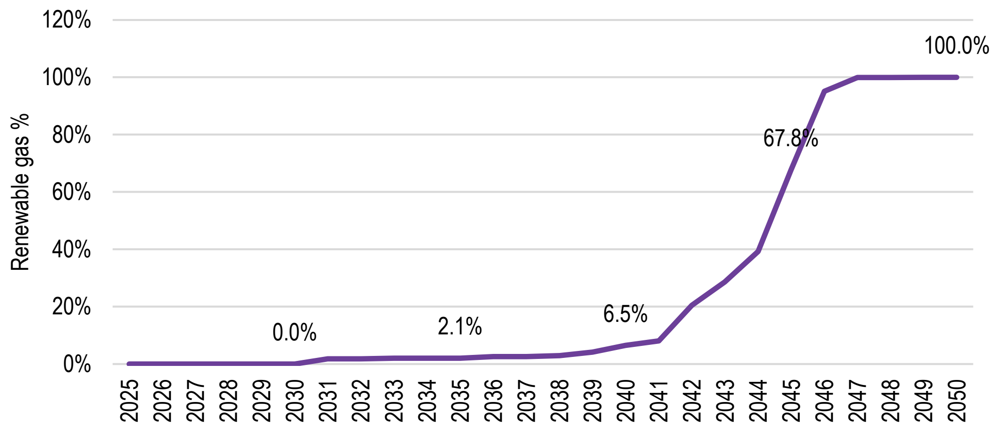
Figure 3.8 Development of renewable gases: Theoretical Efficient Policy scenario (PJ)



Source: ACIL Allen Gas Transition Model

The share of renewable gases in the wider gaseous fuel mix (Figure 3.9) ramps up slowly, reaching 1.8% by 2031 and 2.1% by 2035. The renewable gas share accelerates from 6.5% in 2040 to almost 68% by 2045 and reaches 100% in the late 2040s as conventional natural gas is removed from the system.

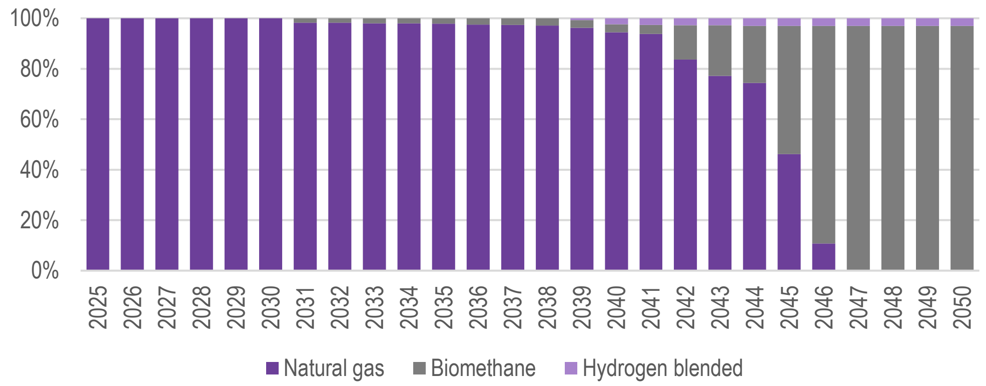
Figure 3.9 Renewable gas share: Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

The GTM allows users to either consume a blended gas product comprising natural gas, biomethane, synthetic methane and hydrogen (consistent with a hydrogen blending limit of up to 3%), or 100% hydrogen using dedicated hydrogen supply. Figure 3.10 examines the composition of the blended gas stream, that is, excluding dedicated hydrogen supply. This shows how the composition of gas supply will change, on average, for gas users that do not make specific adjustments to electrify or adopt hydrogen, and demonstrates how the share of biomethane in the blended gas stream grows rapidly during the 2040s to phase out natural gas use. A small portion of blended hydrogen is present from 2039 onwards.

Figure 3.10 Composition of blended gas stream, by gas type: Theoretical Efficient Policy scenario

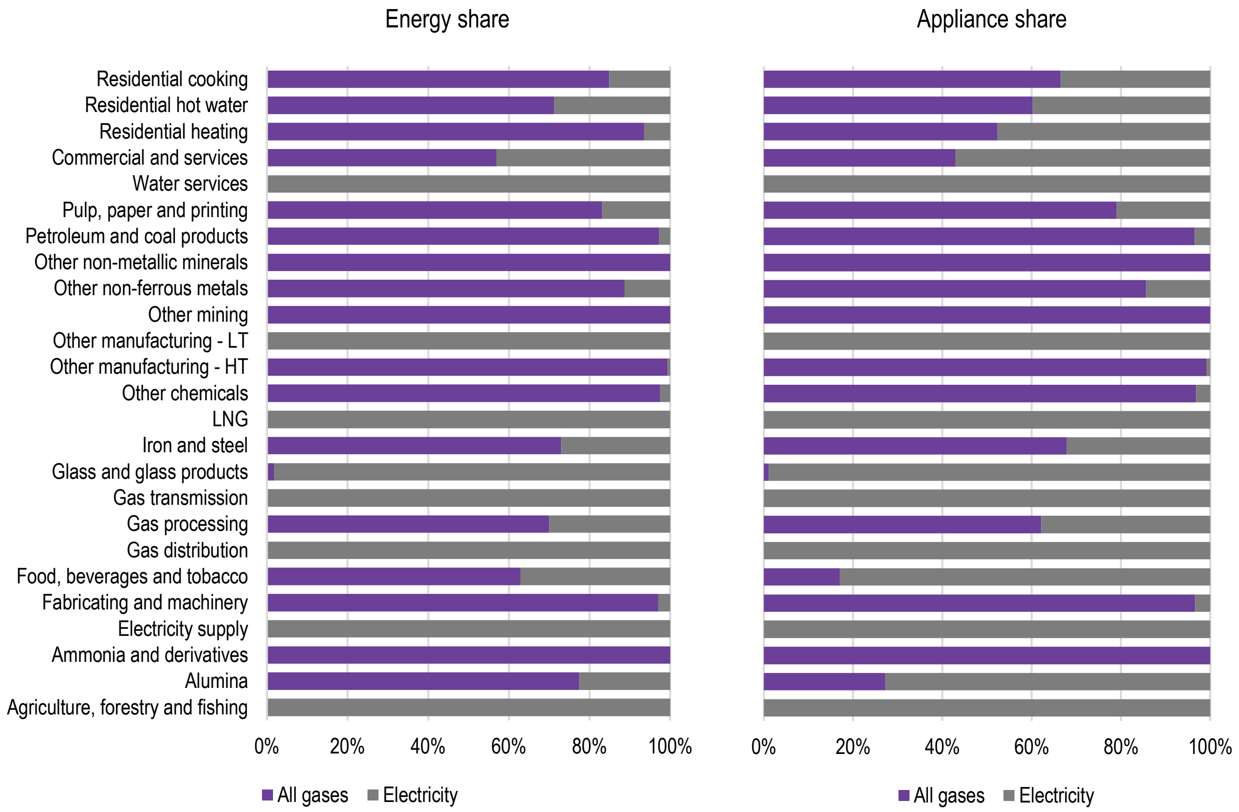


Source: ACIL Allen Gas Transition Model

Figure 3.11 provides the energy and appliance use shares by sector in 2050. The ultimate mix of fuels is approximately two-thirds gaseous fuels and one-third electricity in 2050 but, importantly, the mix of fuels in individual sectors is varied and often includes a combination of both gaseous fuels and electricity. This indicates that renewable gases are useful energy sources for a range of sectors and policy-makers should be flexible and avoid one-size-fits-all approaches. Detailed sectoral level results as presented in Figure 3.11 should be treated with a degree of caution as each sector is represented by a small number of generalised activity types, and in practice users in some sectors will have a more diverse range of energy needs, and face different drivers and barriers when decarbonising. That said the sectoral trends reflect at a high-level the different economic of electrifying or using renewable gas in different sectors, for example:

— it is more economical to electrify low-temperature industrial processes than high-temperature industrial processes due to the ability to use heat pumps for low temperature processes
— compression requirements, such as in the LNG, gas processing and gas transportation sectors, are relatively economical to electrify
— feedstock activities as found in the ammonia and derivatives sector cannot be directly electrified and must use a gaseous feedstock.

Figure 3.11 Energy and appliance shares by sector and fuel type in 2050: Theoretical Efficient Policy scenario

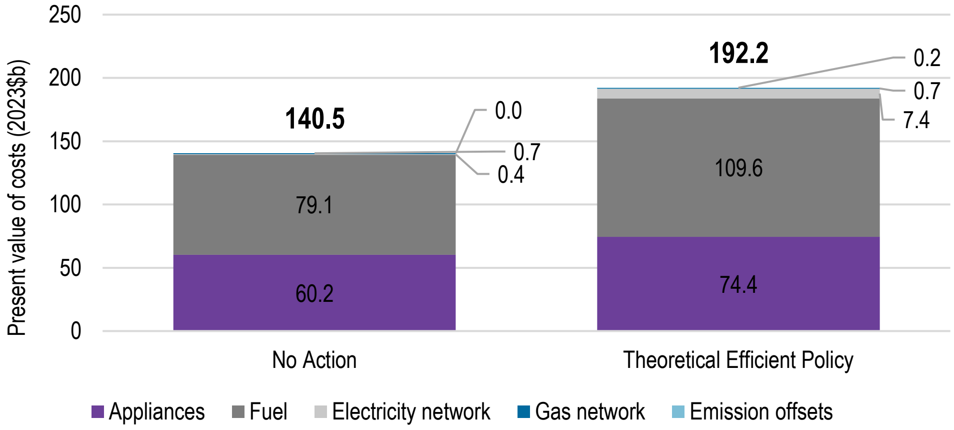


Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.12 compares the present value of costs in the Theoretical Efficient Policy scenario to those in the No Action scenario. The emissions reduction objectives in the Theoretical Efficient Policy scenario increase costs by around $52 billion relative to the No Action scenario, from about $140 billion to almost $192 billion. When compared to the abatement achieved relative to the No Action scenario, the Theoretical Efficient Policy scenario yields an average abatement cost of around $143/tonne CO_2-e.[16]

[16] To calculate a levelised cost of abatement, the difference in emissions must be calculated in present value terms (to compare to costs, which are also compared in present value terms). This is conceptually equivalent to accepted methods for calculating the levelised cost of energy (LCOE), which discounts both costs and energy production. The difference in the present value of emissions between the two scenarios is 367 Mt CO_2-e.

Figure 3.12 Present value of costs by category, 2025 to 2060: Theoretical Efficient Policy scenario compared to No Action scenario



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

As noted above, the outcomes under the Theoretical Efficient Policy scenario represent a theoretical optimal outcome where the sector is exposed to a uniform emissions budget and each end user made switching decisions (both the technology and timing of the switch) in a manner which resulted in the lowest overall resource cost outcome. In practice, end users are making individual decisions which maximise utility, given the relative prices they are exposed to, and policy and regulatory settings can only change those relative prices or limit the choices gas users may make.

Further, while the model can identify a least-cost outcome given the assumptions available to it in an environment of perfect foresight and complete knowledge, in practice, policy-makers and gas users both operate in an environment of imperfect information. For this reason, policy scenarios that reflect policies that are practically implementable will result in higher resource costs. Nevertheless, the Theoretical Efficient Policy scenario is a useful benchmark for comparing the relative efficiency of various real world policy scenarios, as discussed in subsequent sections.

3.2.1 Sensitivities on core model assumptions

We undertook six sensitivities on the Theoretical Efficient Policy scenario to assess how outcomes would vary overall, and at the sectoral level, in the event of plausible variations to the core model assumptions (Table 3.1). Sensitivity analysis supports robust policy-making for an uncertain future by illustrating how outcomes may vary if key technology and cost drivers vary from our core assumptions. This is important as future appliance and energy cost trends are inherently uncertain, particularly over long modelling timeframes. The logic of each sensitivity is explained below:

— We tested a number of hydrogen cost sensitivities but chose a 20% reduction in cost for the Hydrogen Cost sensitivity as it was sufficient to change a significant change in the overall and sector-level role of hydrogen, relative to both biomethane and electricity.

— The No Biomethane sensitivity explores a potential future where biomass suitable for biomethane production is diverted to sectors other than gas-using sectors, for example to provide renewable liquid fuels for hard-to-abate sectors such as aviation, shipping and long-distance land transport, and so is not available to the gas sector.

— The High Renewable Gas and High Electrification sensitivities explore 'stretch' outcomes when assumptions move favourable for renewable gas or electrification, respectively, to understand how this might affect the relative roles of gaseous fuels and electricity.

— The High Hydrogen and High Biomethane sensitivities focus on how the respective roles these two main renewable gas options might change if outcomes move favourably for one and unfavourably for the other.

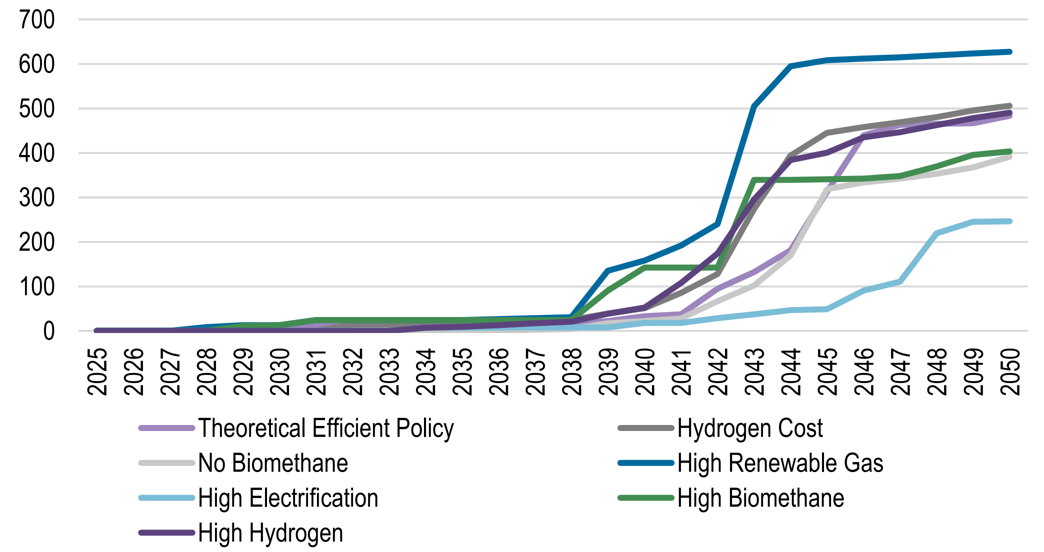
Table 3.1 Assumption variations for sensitivities

Sensitivity	Electrical appliance capital cost	Wholesale hydrogen cost	Wholesale biomethane cost	Biomethane availability (volume)
Hydrogen Cost		-20%		
No Biomethane				-100%
High Renewable Gas	+20%	-20%	-20%	+50%
High Electrification	-20%	+20%	+20%	-50%
High Hydrogen		-20%	+20%	-50%
High Biomethane		+20%	-20%	+50%

Source: ACIL Allen assumptions

The sensitivity analysis demonstrates that we can expect renewable gas to play a material role in decarbonising Australia, even if cost trends move favourably for electrification relative to our core assumptions. The High Electrification sensitivity still deploys about 250 PJ of renewable gas by 2050 to decarbonise Australia's existing gas-using sectors, while more than 600 PJ is needed by 2050 in the High Renewable Gas sensitivity (Figure 3.13). While the variation in results between the sensitivities show that the precise timing and scale of renewable gas development is uncertain, policy-makers can have a high degree of confidence that policies will be needed to support the development of a sizable renewable gas industry that is capable of supplying multiple hundreds of petajoules by 2050. Further, while these results indicate that renewable gas is primarily developed during the late 2030s and 2040s, the modelling results assume perfect foresight and do not include real world factors such as the time needed to develop industry capability, and so we consider that there is a strong policy argument for starting the development of renewable gas industry well before the modelled ramp up (see further discussion in section 3.4).

Figure 3.13 Renewable gas volumes (PJ): Theoretical Efficient Policy scenario compared to sensitivities



Source: ACIL Allen Gas Transition Model

The sensitivity analysis also gives insight into the potential role of gaseous fuels and electricity at the sectoral level (Figure 3.14). Across all gas-using sectors, the long-run share of energy supplied by gaseous fuels is between 50% and 75% under all sensitivities modelled, with most sensitivities around 65%. This gives a high degree of confidence that gaseous fuels will have a long-term role across many of today's gas-using sectors, and that renewable gases will play a material role in decarbonising these sectors.

Looking at the residential, commercial and industrial sectors separately, we can see that the volume of gaseous fuel used in the residential and commercial sectors varies more in response to changes in assumptions than the volume in the industrial sector:

— Gaseous fuels supply about 80% of energy or more in the residential sector under all sensitivities, except the High Electrification sensitivity, where it falls to below 50%.

— The share of energy supplied by gaseous fuels and electricity in the commercial sector is relatively well balanced in the long-run under most sensitivities, but the High Electrification sensitivity sees gaseous fuel use fall to zero by 2050.[17]

— The industrial sector sees gaseous fuels supply the majority of energy (more than 50%), even under the High Electrification sensitivity, and up to 70% in the High Renewable Gas sensitivity. This significant ongoing role for gaseous fuels reflects the existence of large feedstock and high temperature industrial activities that are difficult or impossible to directly electrify.

A further area of interest in the sensitivities is outcomes in the residential sector, as this has significant implications for the management and transition of both millions of small gas customers and the extensive gas distribution networks that supply them. The Theoretical Efficient Policy scenario found that households primarily used biomethane rather than hydrogen for their gaseous fuel needs, as this avoided significant appliance replacement costs associated with moving to hydrogen. However, this outcome reflects one set of assumptions, and our sensitivity analysis demonstrated that a range of plausible futures exist where hydrogen could play a significant role in the residential sector.

The residential fuel mix in these model runs are shown for comparison in Figure 3.15. These charts illustrate that:

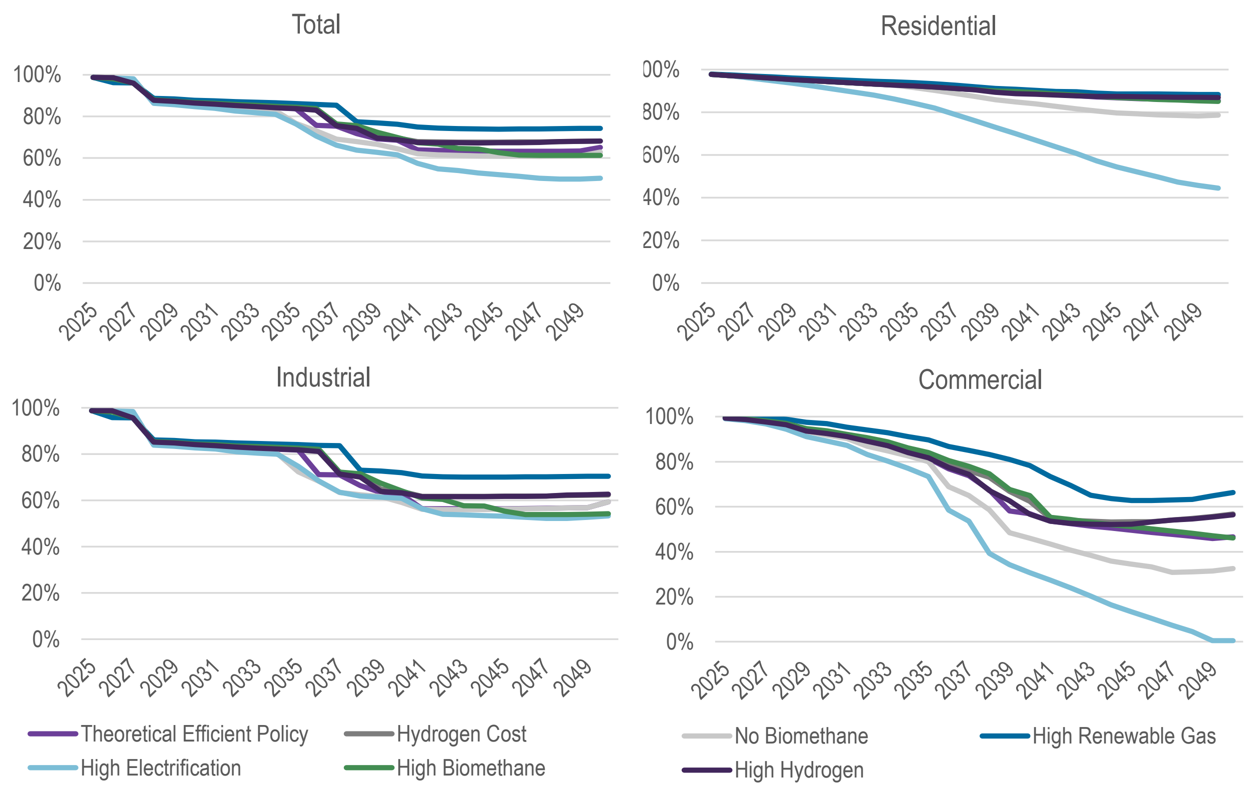
— a range of plausible transition pathways are possible, including significant use of biomethane (Theoretical Efficient Policy scenario), hydrogen (High Hydrogen sensitivity), electrification (High Electrification sensitivity) and natural gas (No Biomethane sensitivity – natural gas use is combined with offsets from 2050 to achieve net zero).

— whereas biomethane is a 'supply-side' transition that does not involve appliance changeover, and so can occur rapidly when the supply-side economics are favourable, a switch to hydrogen tends to occur more gradually to manage the cost of appliance replacement.

— where biomethane is less available or unavailable, natural gas tends to play a role in 2050 (at which time the model requires emissions from this natural gas use to be offset to achieve net zero). Continuing to use natural gas in small volumes in 2050 (and beyond) allows the model to replace household appliances more gradually, reducing and deferring the costs of this process.

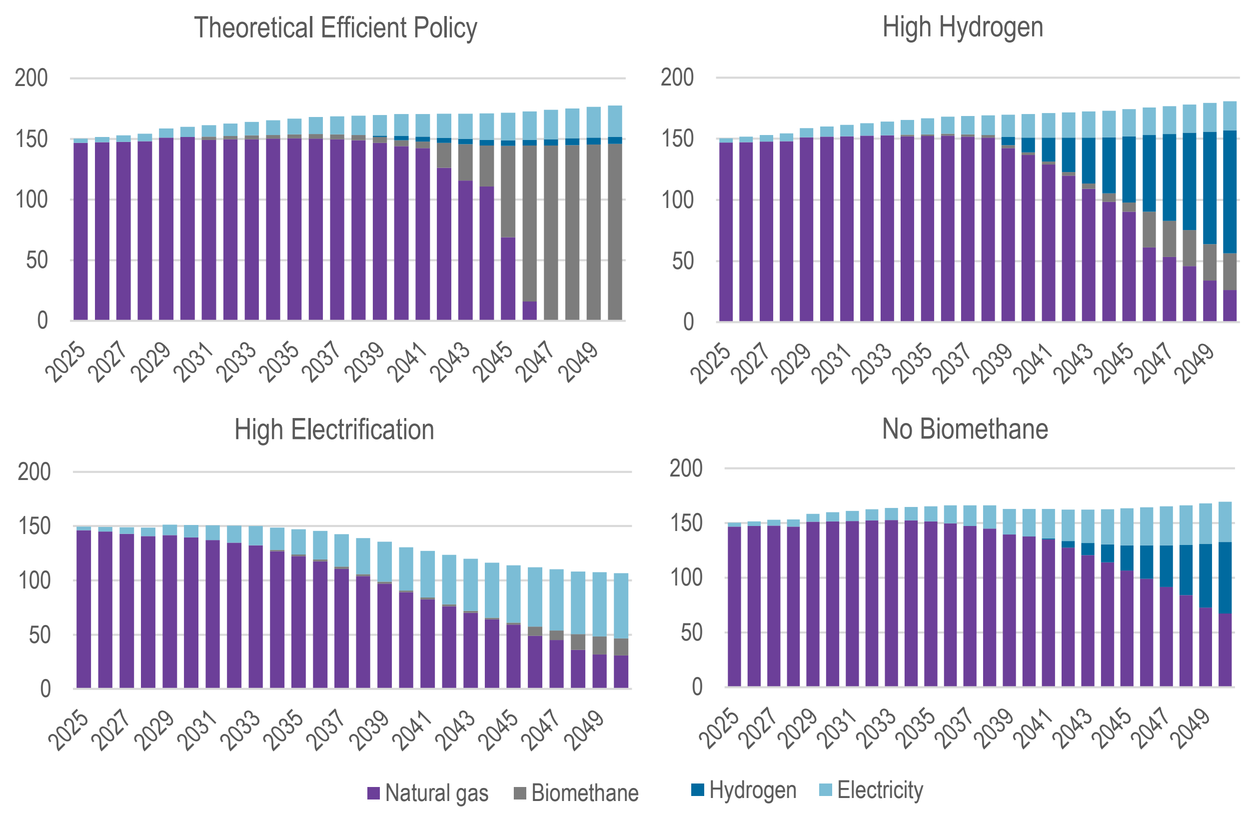
[17] Given the broad-scale of the Gas Transition Model, it is not possible to represent all sub-sectoral activities in great detail (activities modelled are listed in **Table 2.2**). For example, we do not explicitly model activities such as crematoria in the commercial sector, which will be more difficult to electrify than generalised cooking, water heating and space heating activities. Therefore outcomes such as zero gaseous fuel use in the commercial sector should be seen as a stylised high-level finding, that does not fully capture the transition options and challenges of all commercial sub-sectors.

Figure 3.14 Gaseous fuels share (%): Theoretical Efficient Policy scenario and sensitivities, overall and by sector



Source: ACIL Allen Gas Transition Model

Figure 3.15 Residential fuel mix (PJ): Theoretical Efficient Policy scenario and selected sensitivities



Source: ACIL Allen Gas Transition Model

Further details of the six assumption-based sensitivities are provided in Appendix E.

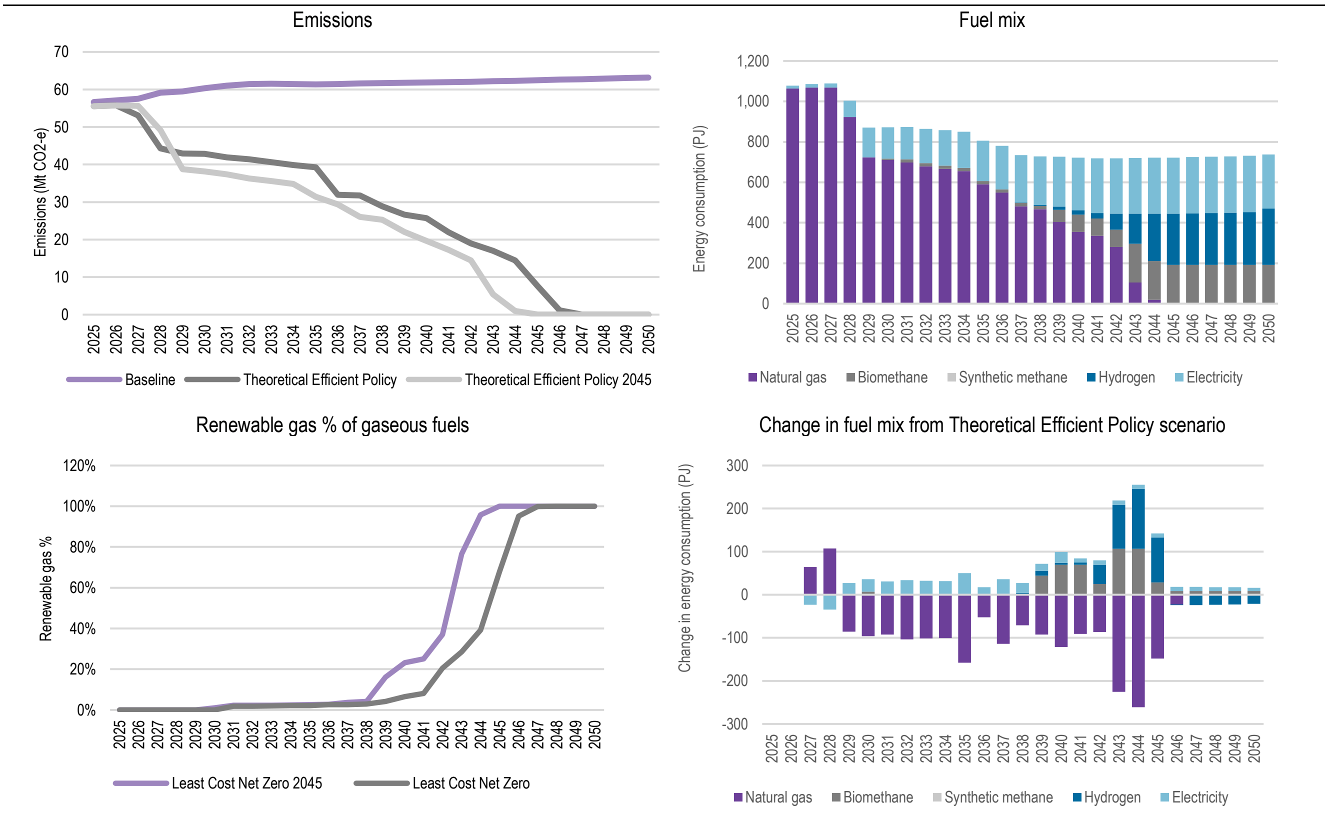
3.2.2 Sensitivity on the effect of achieving net zero by 2045

We also carried out a sensitivity to examine the impact of a more stringent emissions constraint with net zero being required earlier by 2045 rather than 2050. In this sensitivity the 2025 to 2050 emissions budget was adjusted down to 607.7 Mt CO_2-e from 719.4 Mt CO_2-e, reflecting a budget consistent with a straight-line reduction in emissions from projected 2030 levels to net zero in 2045 rather than by 2050.

In the Theoretical Efficient Policy scenario, the development of renewable gases is delayed, reflecting the ongoing reduction in costs the models sees with perfect foresight and the desire to defer capital expenditure as much as possible to reduce its cost in present value terms.

Figure 3.16 presents a snapshot of results from the Theoretical Efficient Policy 2045 sensitivity. The more stringent abatement task is achieved by a small amount of additional annual electrification in the first half of the projection period and a large acceleration of biomethane and hydrogen in the early 2040s. Aggregate resource costs are around $201 billion ($9.2 billion higher with the 2050 target), giving an average abatement cost of $153/tonne CO_2-e ($10/tonne CO_2-e higher than the Theoretical Efficient Policy scenario). The higher per unit abatement cost is unsurprising, given that the faster decarbonisation profile requires the model to replace capital earlier and adopt renewable gases and electrification faster than in the Theoretical Efficient Policy scenario.

Figure 3.16 Theoretical Efficient Policy 2045 sensitivity results summary



Source: ACIL Allen Gas Transition Model

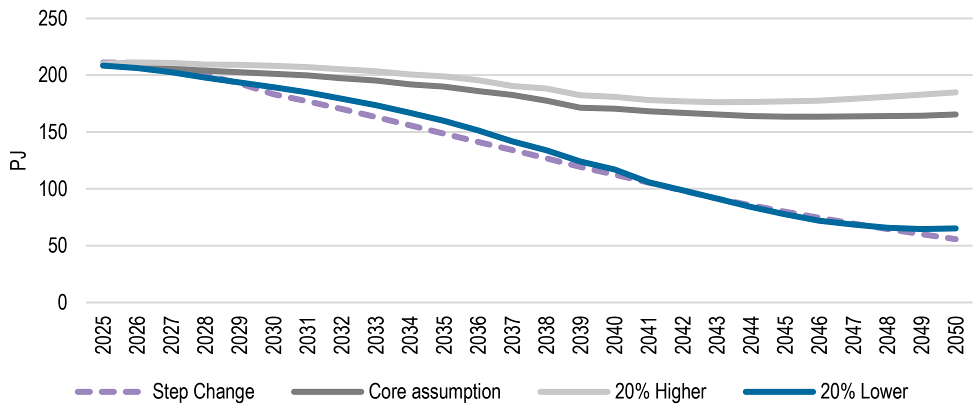
3.2.3 Sensitivity exploring the effect of variations in electrical appliance costs

We undertook further sensitivity analysis on the Theoretical Efficient Policy scenario to understand the effect of variations in capital costs for residential and commercial electrical appliances on outcomes. Sensitivity analysis helps us to understand the effect of these variations as assumptions are inherently uncertain and in practice costs will vary between individual users, resulting in a mix of outcomes across a real-world population of residential and commercial gas users.

Figure 3.17 presents the level of gaseous fuel use across residential and commercial gas users with a variation to electrical appliance costs of 20% higher and lower. We found that pathways are highly sensitive to assumed costs, with results being asymmetrical. A 20% reduction in electrical appliance costs relative to our core assumptions resulting in a level of electrification comparable to the Active Policy + Step Change sensitivity discussed in section 3.1. On the other hand a 20% increase to electrical appliance costs only increased gaseous fuel consumption by around 12% in 2050.

Given this sensitivity, and the likely real-world variations in costs between different users, it is important that policy-makers do not adopt a 'one-size-fits-all' approach to residential and commercial decarbonisation, but instead gives users options and flexibility to choose the decarbonisation option that best suits their circumstances.

Figure 3.17 Gaseous fuel consumed by commercial and residential customers: impact of variations to electrical appliance costs



Source: ACIL Allen Gas Transition Model

3.3 Electrify Everything Possible scenario

The Electrify Everything Possible scenario is designed to compare the cost of a heavily electrification-focused approach to achieving net zero to the theoretical optimal outcome in the Theoretical Efficient Policy scenario. The scenario:

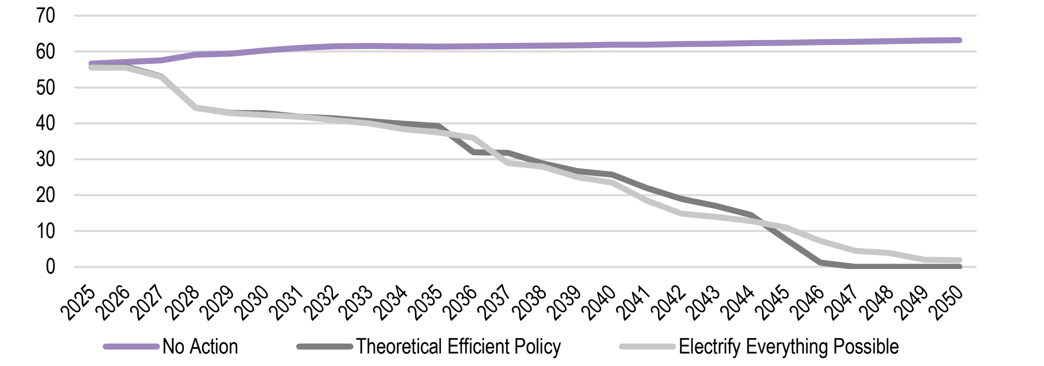
— adopts the same overall (gas sector-wide) emissions budgets as used in the Theoretical Efficient Policy scenario, to ensure a comparable emissions outcome

— adopts the Victorian and ACT restrictions on new residential gas connections

— restricts uptake of renewable gas options other than for activities where electrification is not possible or proven (such as feedstock and some very high temperature processes, to mimic a heavily electrification-focused policy approach to achieving net zero.

Figure 3.18 shows the emissions trajectory under the Electrify Everything Possible scenario relative to the No Action and Theoretical Efficient Policy scenarios. The Electrify Everything Possible scenario tracks closely to the Theoretical Efficient Policy scenario, reflecting the equivalent emissions budget used in both scenarios, with slight divergences in some years.

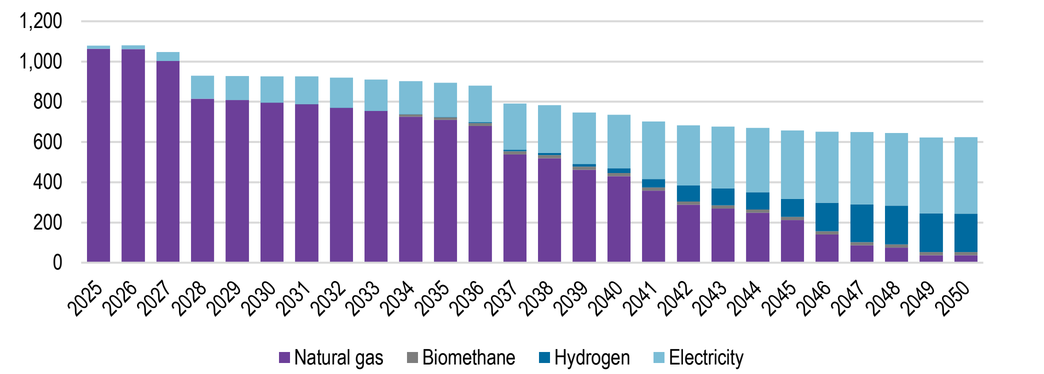
Figure 3.18 Emissions: Electrify Everything Possible scenario relative to Theoretical Efficient Policy and No Action scenarios (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

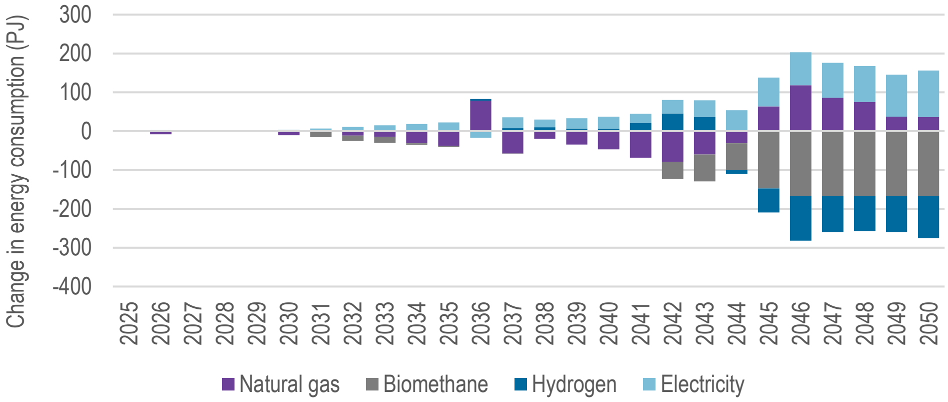
Figure 3.19 shows the mix of fuels used in the Electrify Everything Possible scenario. Reflecting the assumed approach, electricity plays a much greater role in the fuel mix than in the Theoretical Efficient Policy scenario, particularly post-2035, while renewable gases play a smaller role (Figure 3.20). Natural gas use is initially lower in the Electrify Everything Possible scenario, reflecting the earlier adoption of electrification, but is higher in the long-run.

Figure 3.19 Fuel mix: Electrify Everything Possible scenario (PJ)



Source: ACIL Allen Gas Transition Model

Figure 3.20 Fuel mix: change between Electrify Everything Possible scenario and Theoretical Efficient Policy scenario

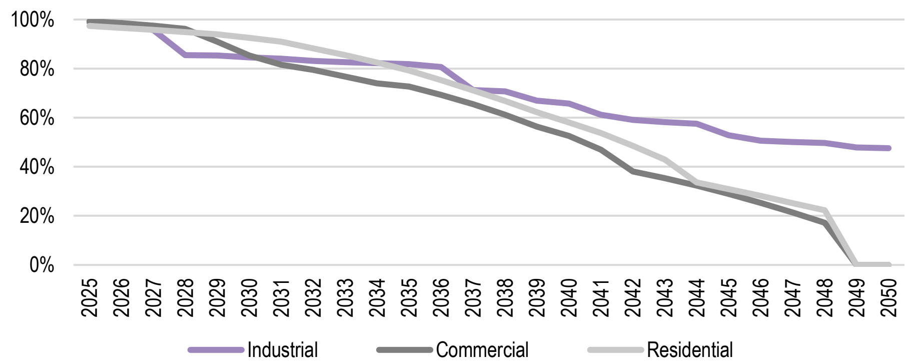


Note: an increase on the y-axis indicates an increase in the use of a fuel in the Electrify Everything Possible scenario relative to the Theoretical Efficient Policy scenario.

Source: ACIL Allen Gas Transition Model

Figure 3.21 demonstrates that in the Electrify Everything Possible scenario the commercial and residential sectors completely electrify by 2050, but gaseous fuels continue to play a significant role in the industrial sector (providing about 50% of energy). This reflects the existince of hard-to-electrify high temperature and feedstock processes in the industrial sector. For the purpose of the modelling we have assumed that renewable gas supply to industry is viable irrespective of whether the residential and commercial sectors electrify, but in practice a decline in demand for gaseous fuels in one sector may affect the viability of supplying other sectors (for example, by reducing the viability of gas networks serving a mix of customers).

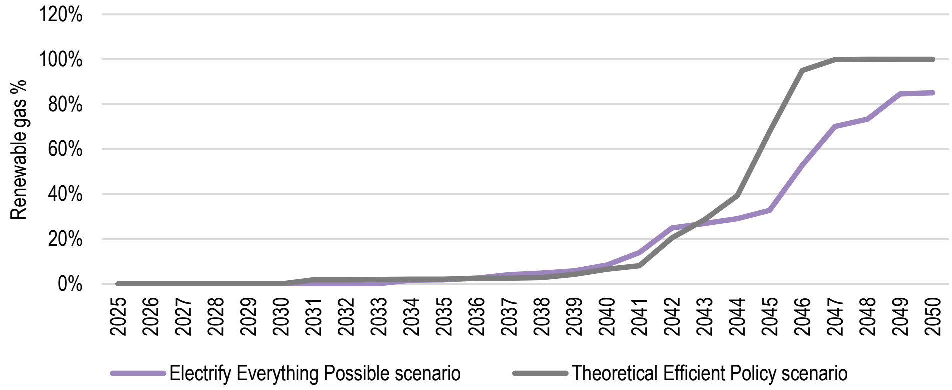
Figure 3.21 Electrify Everything Possible scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Figure 3.22 shows that the Electrify Everything Possible scenario has a significantly lower share of renewable gas than the Theoretical Efficient Policy scenario, reflecting the higher amount of electrification in the Electrify Everything Possible scenario based on assumed electrification policy.

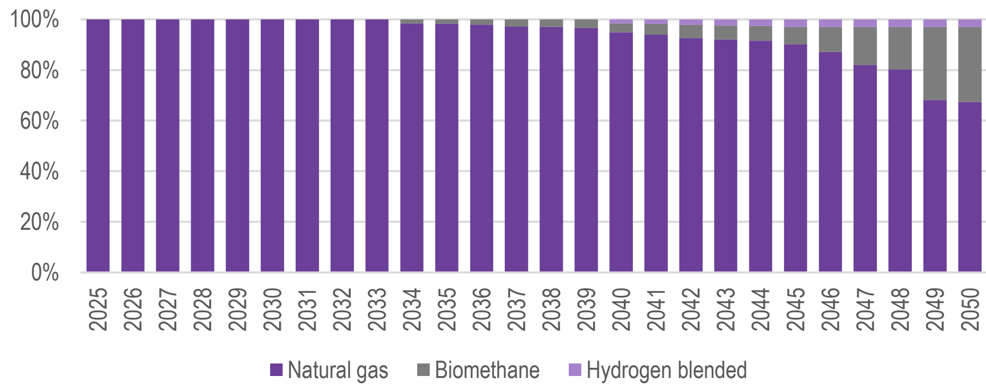
Figure 3.22 Renewable gas percentage of gaseous fuels: Electrify Everything Possible scenario and Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

Figure 3.23 shows the composition of the blended gas stream (excluding dedicated hydrogen supply), and shows how the focus on electrification in this scenario results in a slow change in the composition of blended gas, with biomethane and blended hydrogen remaining a minority share up to and including 2050.

Figure 3.23 Composition of blended gas stream, by gas type: Electrify Everything Possible scenario



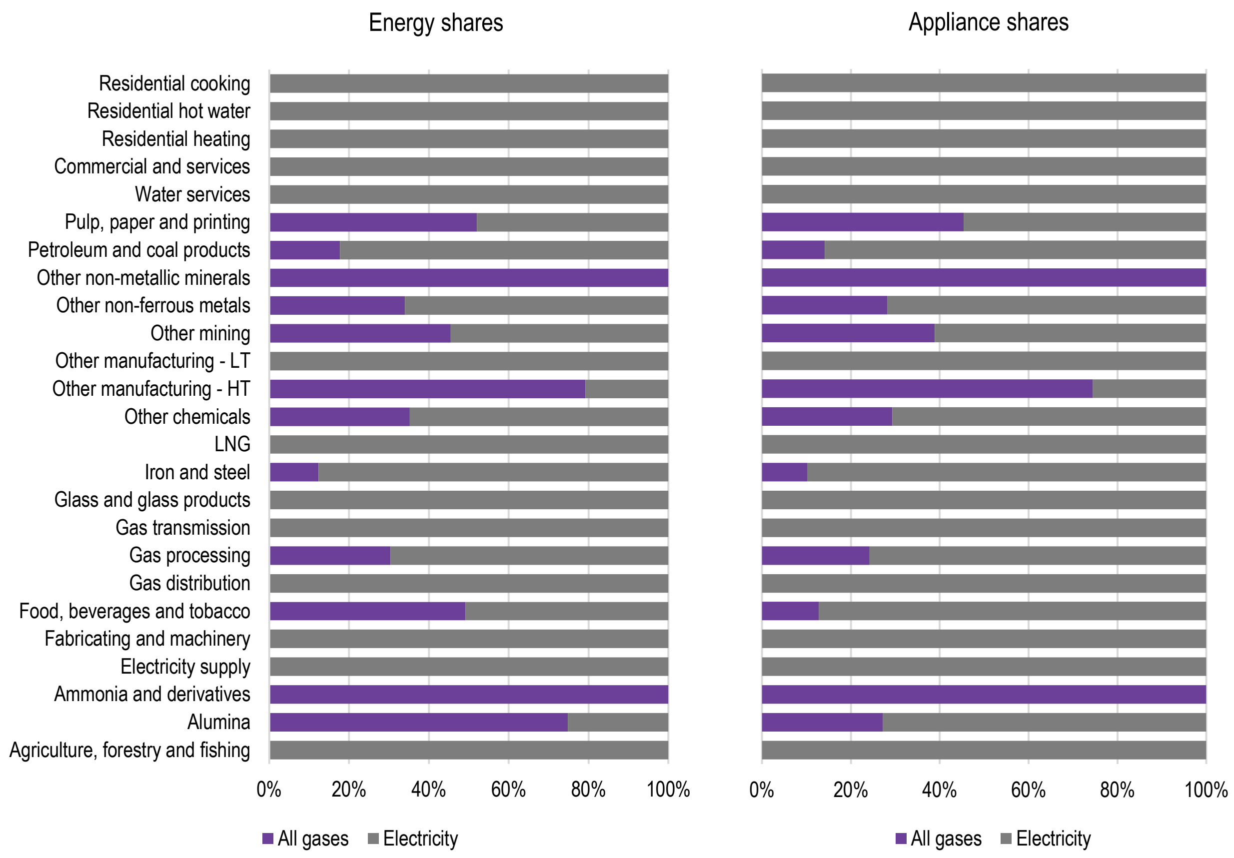
Source: ACIL Allen Gas Transition Model

Figure 3.24 provides a breakdown of fuel use and appliance types by sector on a national level in 2050. Compared to the Theoretical Efficient Policy scenario (Figure 3.11), the Electrify Everything Possible scenario has a much higher degree of electrification, with 120 PJ more electricity use and 239 PJ less gaseous fuel use in 2050 than in the Theoretical Efficient Policy scenario. Gaseous fuel use in the Electrify Everything Possible scenario is concentrated in the alumina, ammonia and non-metallic minerals sectors reflecting the use of gaseous fuels for feedstock and high-temperature calcining. Small volumes of gaseous fuels are use in other sectors, which reflect appliances continuing to use natural gas because electrification of those appliances is not necessary to achieve the overall emissions budget.[18] As noted in section 3.2, detailed sectoral level results as presented in Figure 3.24 should be treated with a degree of caution as each sector is represented by a small number of generalised activity types, and in practice users in some sectors

[18] If we forced the model to electrify these appliances we would over-achieve the total emissions budget, making comparisons across scenarios harder.

will have a more diverse range of energy needs, and face different drivers and barriers when decarbonising.

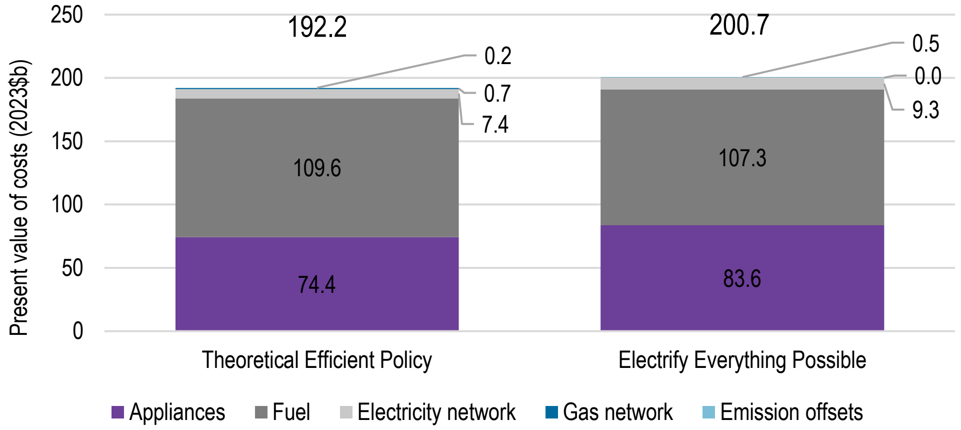
Figure 3.24 Energy and appliance shares by sector and fuel type in 2050: Electrify Everything Possible scenario



Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.25 compares the present value of costs in the Electrify Everything Possible scenario to those in the Theoretical Efficient Policy scenario. Costs are higher in the Electrify Everything Possible scenario at almost $201 billion, compared to $192 billion in the Theoretical Efficient Policy scenario. The higher overall cost of the Electrify Everything Possible scenario translates to a higher average cost of abatement – around $165/tonne CO_2-e compared to the $143/tonne CO_2-e achieved in the Theoretical Efficient Policy scenario.

Figure 3.25 Present value of costs by category, 2025 to 2060: Electrify Everything Possible scenario compared to Theoretical Efficient Policy scenario



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

The higher costs in the Electrify Everything Possible scenario relative to the Theoretical Efficient Policy scenario are not surprising given that the Electrify Everything Possible scenario requires users in some sectors to reduce emissions through electrification where renewable gases provide a lower-cost option. However, this result does provide some policy insights:

— Policies that force one approach over another will tend to increase costs relative to more broadly-based policies that allow different sectors and users to identify the best fuel and appliance mix for decarbonising their activities. In this case, a significant electrification requirement increases costs relative to a more neutral policy that gives these users freedom to choose between renewable gas and electrification.

— A complete electrification solution is unlikely to be economically optimal, and renewables gases are, if supported alongside electrification through policy settings, likely to play a key role in both the short- and long-term.

3.4 Optimal RGT scenario

The Optimal RGT scenario is designed to achieve a gradually increasing RGT that broadly reflects the level of renewable gas achieved in the Theoretical Efficient Policy scenario, but which slightly accelerates the uptake of renewable gases to reflect a more realistic ramp-up of the industry. The Optimal RGT trajectory modelled requires renewable gases to reach the following shares of total gaseous fuel consumption:

— 3% by 2030

— 25% by 2040

— 95% by 2050.

While the Theoretical Efficient Policy scenario defers renewable gas investment as late as possible, and primarily develops this supply source from around 2039, this pathway is unlikely to be practically feasible or desirable for several reasons:

— It takes time to develop industry capability and skills to deliver projects, and the renewable gas industry is unlikely to be able to ramp as fast as is modelled in the Theoretical Efficient Policy scenario without earlier investment to gradually build industry capacity.

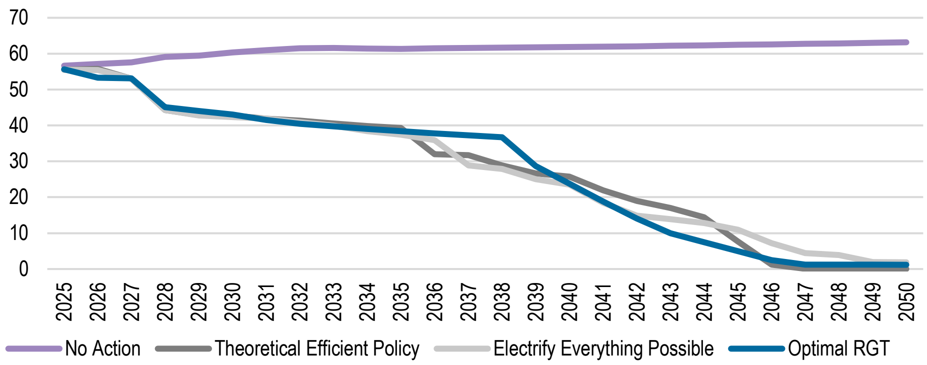
— Leaving renewable gas investment to the latest 'optimal' point in time is a risky strategy in the real world given the risk that projects will be delayed or supply chain constraints may not support extremely rapid ramping of capacity. For example, these real-world constraints are evident in some of the challenges faced by the electricity industry in rapidly ramping renewable generation capacity.

— Demonstrating the technical feasibility and real-world economics of renewable gas will be important to build confidence of gas users to choose this decarbonisation option. While electricity supply side decarbonisation has been demonstrated as a feasible pathway, delaying significant renewable gas development until the late 2030s could discourage some users from adopting this pathway, even if it is the lowest-cost pathway for them in the long-term – for example due to a desire to achieve interim emissions reduction targets.

Noting that these practical points cannot be fully captured within an optimisation model, which chooses a least cost pathway given a known future, the Optimal RGT scenario will necessarily be higher cost than the Theoretical Efficient Policy scenario. However, it demonstrates the potential increase in cost needed to de-risk the adoption of renewable gas through bringing forward investment and developing the industry. Given the risks noted above, this cost could be considered as a form of insurance, that gives policy-makers and gas users greater confidence that this pathway will be available in time to achieve their decarbonisation objectives.

As with the Electrify Everything Possible scenario, the Optimal RGT scenario adopts the same overall (gas sector-wide) emissions budgets as used in the Theoretical Efficient Policy scenario to ensure a comparable emissions outcome. The emissions trajectory varies slightly between the scenarios, with the Optimal RGT delaying decarbonisation slightly during the late 2030s and then reducing emissions more rapidly during the 2040s to achieve the same budget.

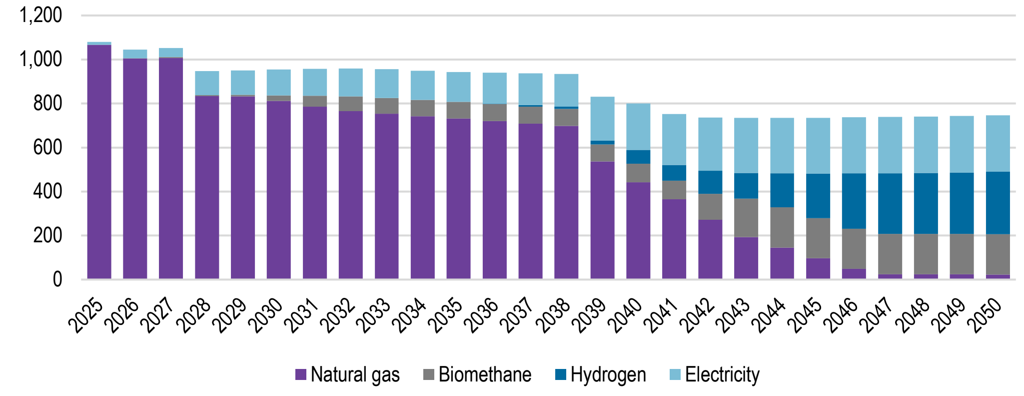
Figure 3.26 Emissions: Optimal RGT scenario relative to No Action, Theoretical Efficient Policy and Electrify Everything Possible scenarios (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

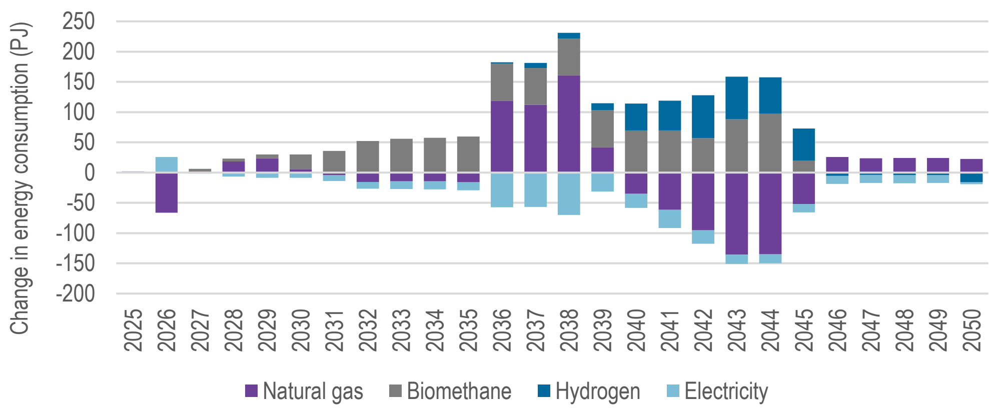
Figure 3.27 shows the mix of fuels used in the Optimal RGT scenario. Reflecting the assumptions of a formal RGT policy to bring forward renewable gas investment, biomethane production is higher than the Theoretical Efficient Policy scenario, particularly during the 2030s, and hydrogen production is higher, particularly during the 2040s (Figure 3.28). Early hydrogen development is also increased during the 2030s, albeit in smaller volumes than biomethane.

Figure 3.27 Fuel mix: Optimal RGT scenario (PJ)



Source: ACIL Allen Gas Transition Model

Figure 3.28 Fuel mix: change between Optimal RGT scenario and Theoretical Efficient Policy scenario

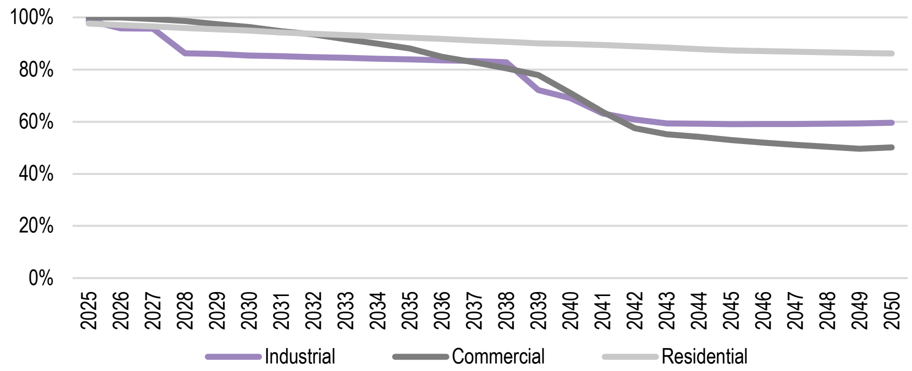


Note: an increase on the y-axis indicates an increase in the use of a fuel in the Optimal RGT scenario relative to the Theoretical Efficient Policy scenario.

Source: ACIL Allen Gas Transition Model

Figure 3.29 shows that gaseous fuels and electricity both play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector.

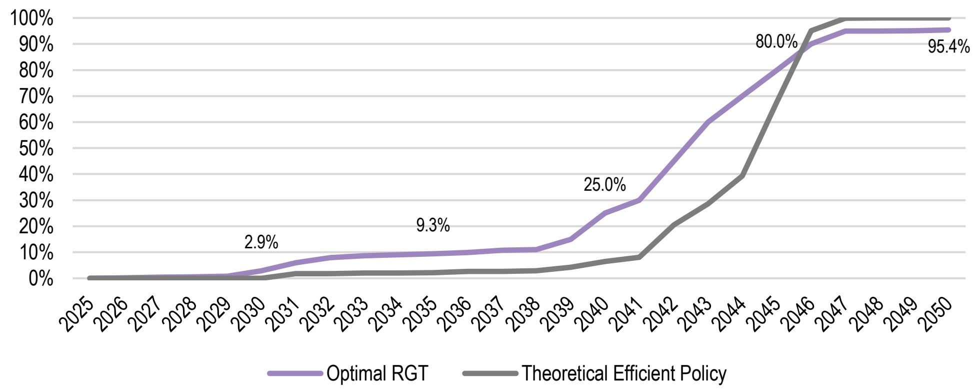
Figure 3.29 Optimal RGT scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Figure 3.30 shows that the Optimal RGT scenario achieves a higher share of renewable gas than the Theoretical Efficient Policy scenario, reflecting the assumed design of the RGT policy to bring forward renewable gas development.

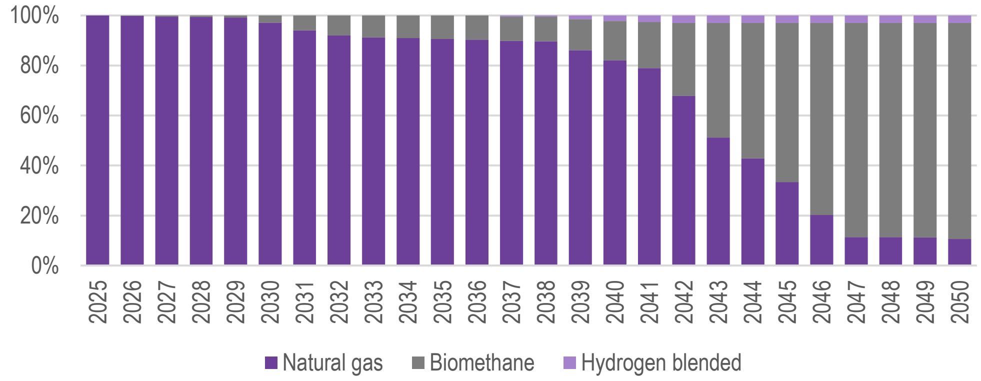
Figure 3.30 Renewable gas share of gaseous fuels: Optimal RGT scenario and Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

Figure 3.36 shows the composition of the blended gas stream (excluding dedicated hydrogen supply), and shows how the development of renewable gases through an RGT sees biomethane become about 10% of the blended gas stream by the mid-2030s, and the majority of that stream by 2044.

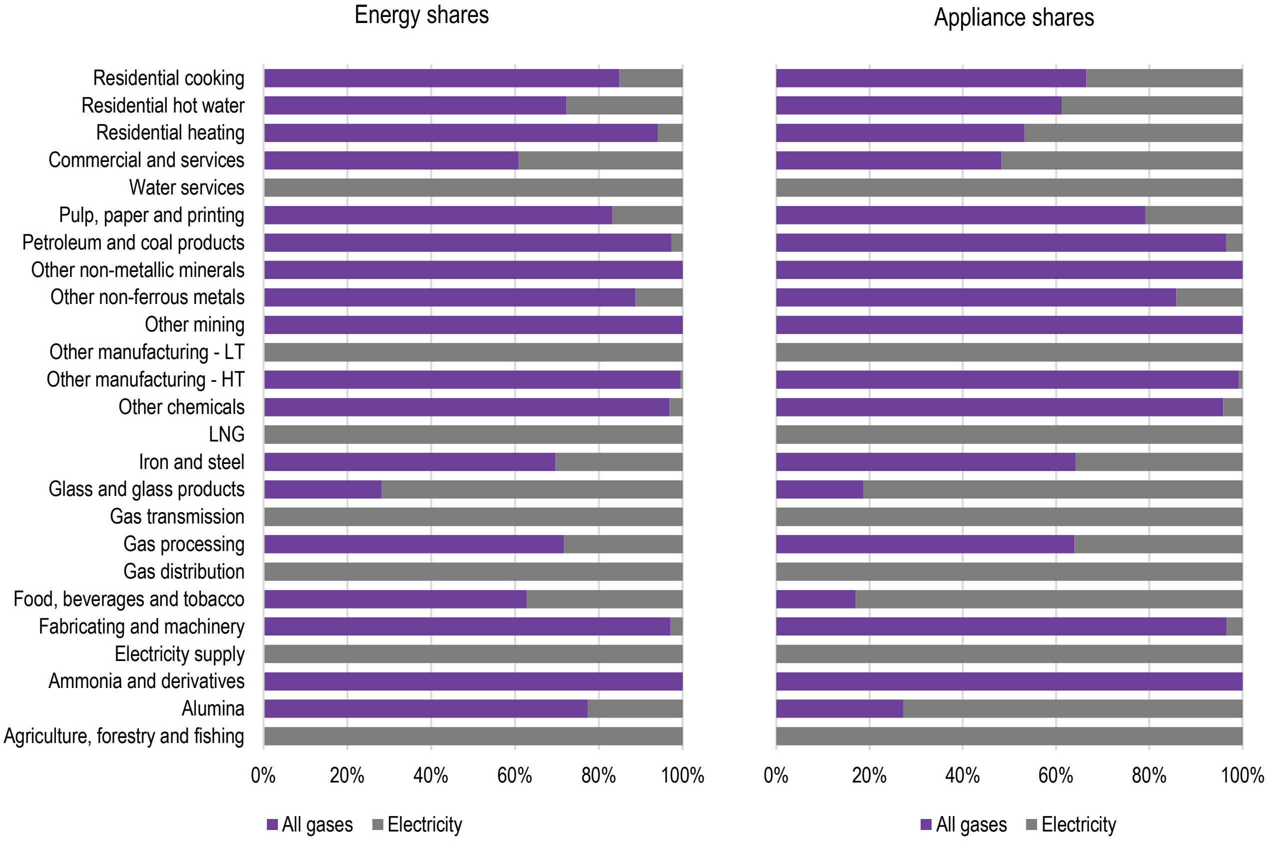
Figure 3.31 Composition of blended gas stream, by gas type: Optimal RGT scenario



Source: ACIL Allen Gas Transition Model

Figure 3.32 provides a breakdown of fuel use and appliance types by sector on a national level in 2050. Compared to the Theoretical Efficient Policy scenario (Figure 3.11), fuel mixes are very similar, with slightly increased use of renewable gases (reflecting the RGT policy) and, consequently, slightly reduced electrification. As noted in section 3.2, detailed sectoral level results as presented in Figure 3.24 should be treated with a degree of caution as each sector is represented by a small number of generalised activity types, and in practice users in some sectors will have a more diverse range of energy needs, and face different drivers and barriers when decarbonising.

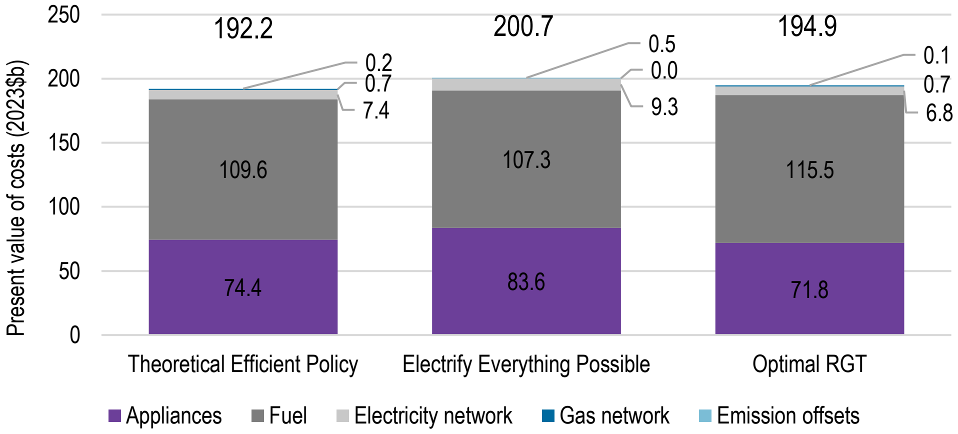
Figure 3.32 Energy and appliance shares by sector and fuel type in 2050: Optimal RGT scenario



Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.33 compares the present value of costs in the Optimal RGT scenario to those in the Theoretical Efficient Policy and Electrify Everything Possible scenarios. The Optimal RGT scenario is slightly more expensive than the Theoretical Efficient Policy scenario, costing $194.9 billion compared to $192.2 billion. However, the Optimal RGT scenario is lower cost than the Electrify Everything Possible scenario, reflecting the more balanced use of both renewable gas and electrification under an RGT policy. Adopting this approach rather than an ‘electrify everything’ approach reduces costs by almost $6 billion in present value terms and reduces the average cost of abatement from $165/tonne CO_2-e to $150/tonne CO_2-e.

Figure 3.33 Present value of costs by category, 2025 to 2060: Theoretical Efficient Policy, Electrify Everything Possible and Optimal RGT scenarios



Note: present value calculated using a 7% discount rate
Source: ACIL Allen Gas Transition Model

The higher costs in the Optimal RGT scenario relative to the Theoretical Efficient Policy scenario are not surprising given that the Theoretical Efficient Policy scenario is optimised to achieve emissions reductions at the lowest cost given the input assumptions. However, as noted above, the Optimal RGT reflects a real-world policy approach to steadily build renewable gas industry capacity through the 2020s and 2030s, to enable it to play its very significant long-term decarbonisation role. The additional $2.6 billion in costs relative to the Theoretical Efficient Policy scenario (a 1.4% increase) represents a small investment to de-risk the development of this option and support the gas sector's long-term transition.

3.5 Accelerated RGT scenario

The Accelerated RGT scenario is designed to achieve faster growth in renewable gases than is achieved under the Optimal RGT or Theoretical Efficient Policy scenarios. This scenario broadly reflects a situation where policy-makers choose to prioritise and accelerate development in renewable gases, potentially due to policy decisions to accelerate national decarbonisation (for example, as part of determining Australia's 2035 Nationally Determined Contributions under the Paris Agreement), a recognition of the importance of these options to achieve long-term decarbonisation, a strategic recognition of the opportunities for renewable gases to underpin emerging export industries such as green hydrogen, green ammonia or green iron, or difficulties in achieving fast and cost-effective abatement from other sectors.

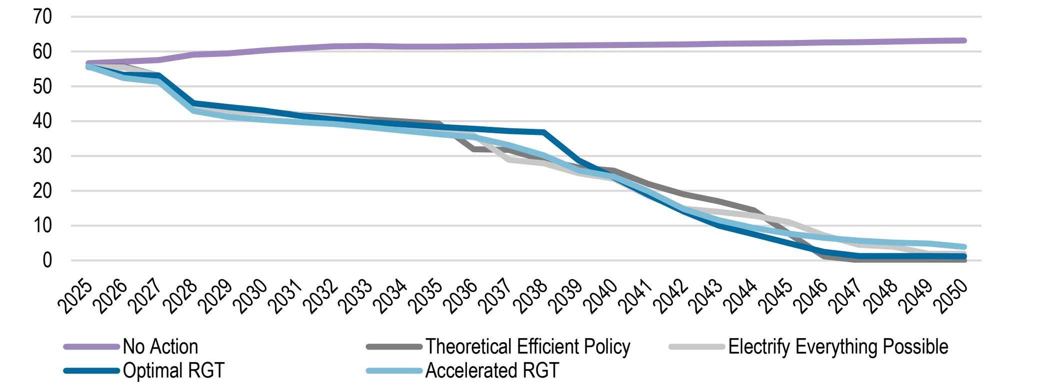
The Accelerated RGT trajectory modelled requires renewable gases to reach the following shares of total gaseous fuel consumption:

— 10% by 2030
— 32% by 2040
— 84% by 2050.

As with the Optimal RGT scenario, accelerating renewable gas uptake relative to the Theoretical Efficient Policy scenario will increase costs within the framework of a perfect foresight optimisation model, but has other real-world benefits such as early development of skills and capabilities, reducing the risk that a rapid ramp-up in renewable gas capacity will be hampered by supply chain or other logistical constraints, and in building users' confidence in the viability of renewable gas as a decarbonisation option.

Unlike the other policy scenarios, the Accelerated RGT scenario is not required to comply with an overall (gas sector-wide) emissions budget, but the ambition of the RGT itself is sufficient to ensure that emissions are significantly lower in this scenario than in the other policy scenarios (Figure 3.35). While the other policy scenarios limit net emissions to 719 Mt CO_2-e over the period from 2025 to 2050, the Accelerated RGT scenario results in 709 Mt CO_2-e over the same period.

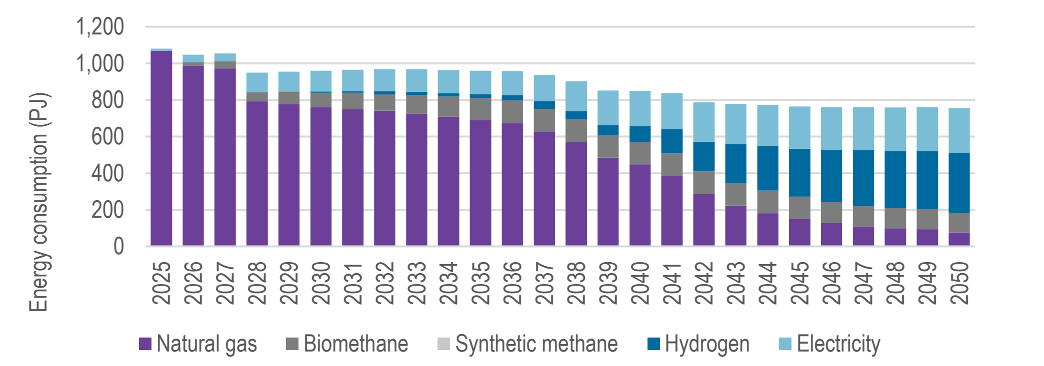
Figure 3.34 Gas sector emissions, by scenario (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

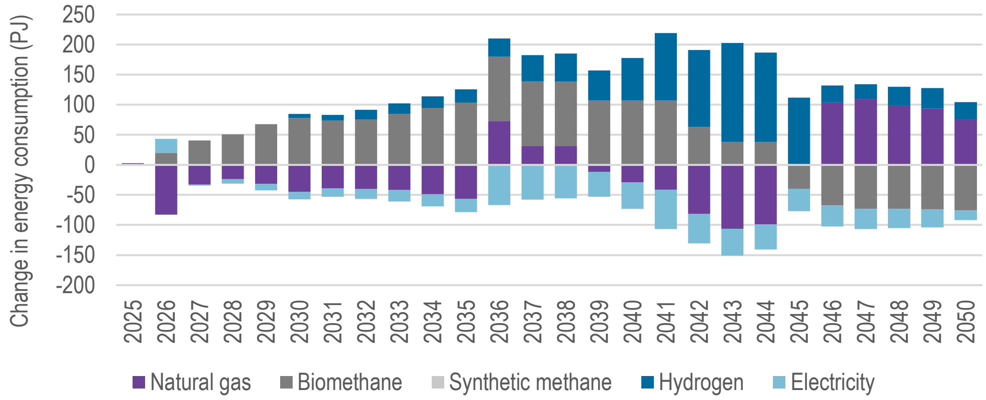
Figure 3.35 shows the mix of fuels used in the Accelerated RGT scenario, while Figure 3.36 shows the significant acceleration of renewable gas production (both biomethane and hydrogen) under the Accelerated RGT relative to the Theoretical Efficient Policy scenario prior to 2045. This acceleration can also be seen by comparing the renewable gas share achieved across the policy scenarios (Figure 3.37). The long-term level of renewable gas is actually slightly lower than under the Theoretical Efficient Policy and Optimal RGT scenarios, which reflects the fact that the earlier uptake of renewable gas means less renewable gas is needed in the long-run to achieve a comparable overall emissions level.

Figure 3.35 Fuel mix: Accelerated RGT scenario (PJ)



Source: ACIL Allen Gas Transition Model

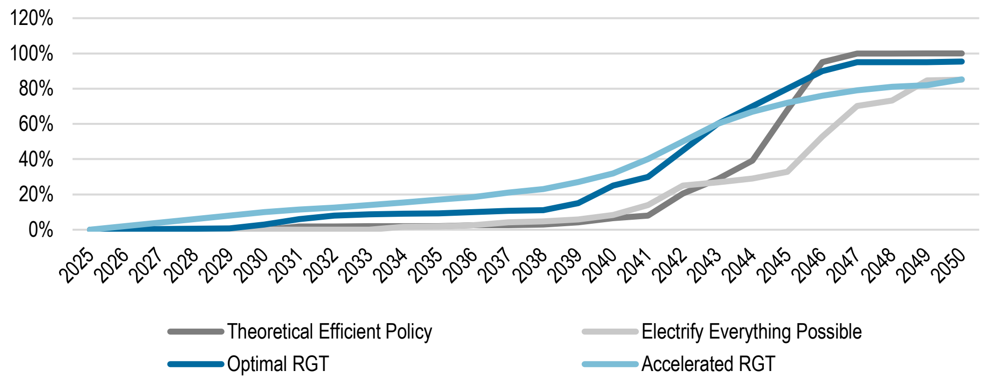
Figure 3.36 Fuel mix: change between Accelerated RGT scenario and Theoretical Efficient Policy scenario



Note: an increase on the y-axis indicates an increase in the use of a fuel in the Accelerated RGT scenario relative to the Theoretical Efficient Policy scenario.

Source: ACIL Allen Gas Transition Model

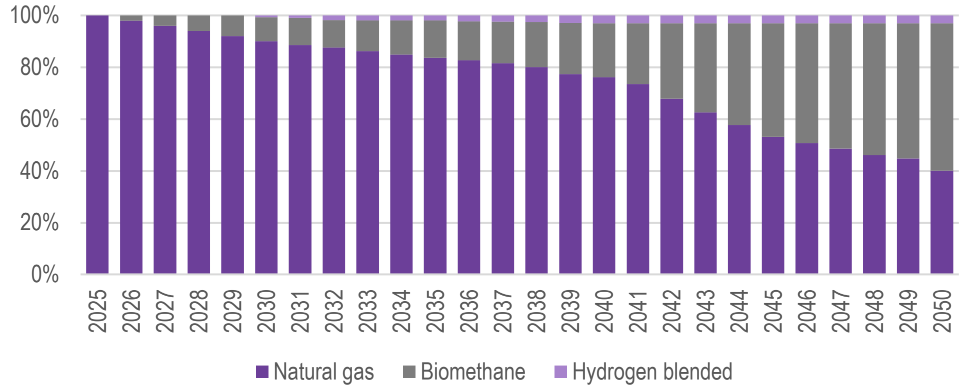
Figure 3.37 Renewable gas share of gaseous fuels, by policy scenario



Source: ACIL Allen Gas Transition Model

Figure 3.38 shows the composition of the blended gas stream (excluding dedicated hydrogen supply), and shows how the accelerated RGT builds the proportion of biomethane in the blended gas stream steadily, reaching about 10% in 2031 and 20% by 2039, and continues growing through the 2040s.

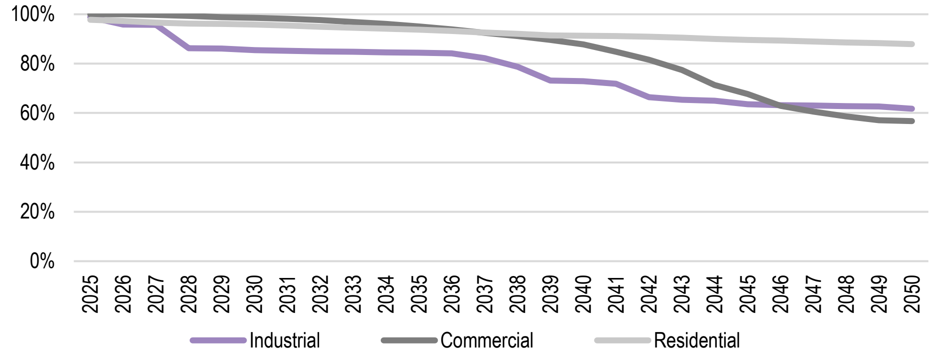
Figure 3.38 Composition of blended gas stream, by gas type: Accelerated RGT scenario



Source: ACIL Allen Gas Transition Model

Figure 3.39 shows that gaseous fuels and electricity both play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector.

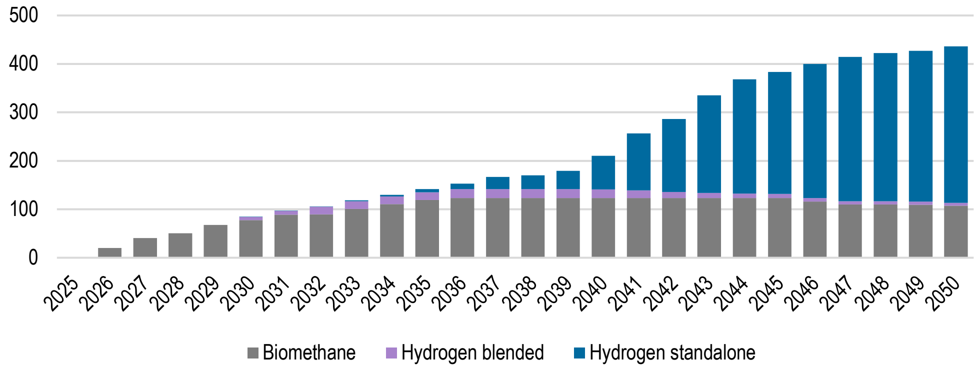
Figure 3.39 Accelerated RGT scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Development of renewable gas is initially focussed on the lower cost biomethane under the Accelerated RGT scenario as shown in Figure 3.40. Hydrogen blending also plays a role is relatively limited due to its blending constraint (3% by energy). Standalone hydrogen is developed rapidly in this scenario with volumes ramping up in the early 2030's to reach 163 PJ by 2042.

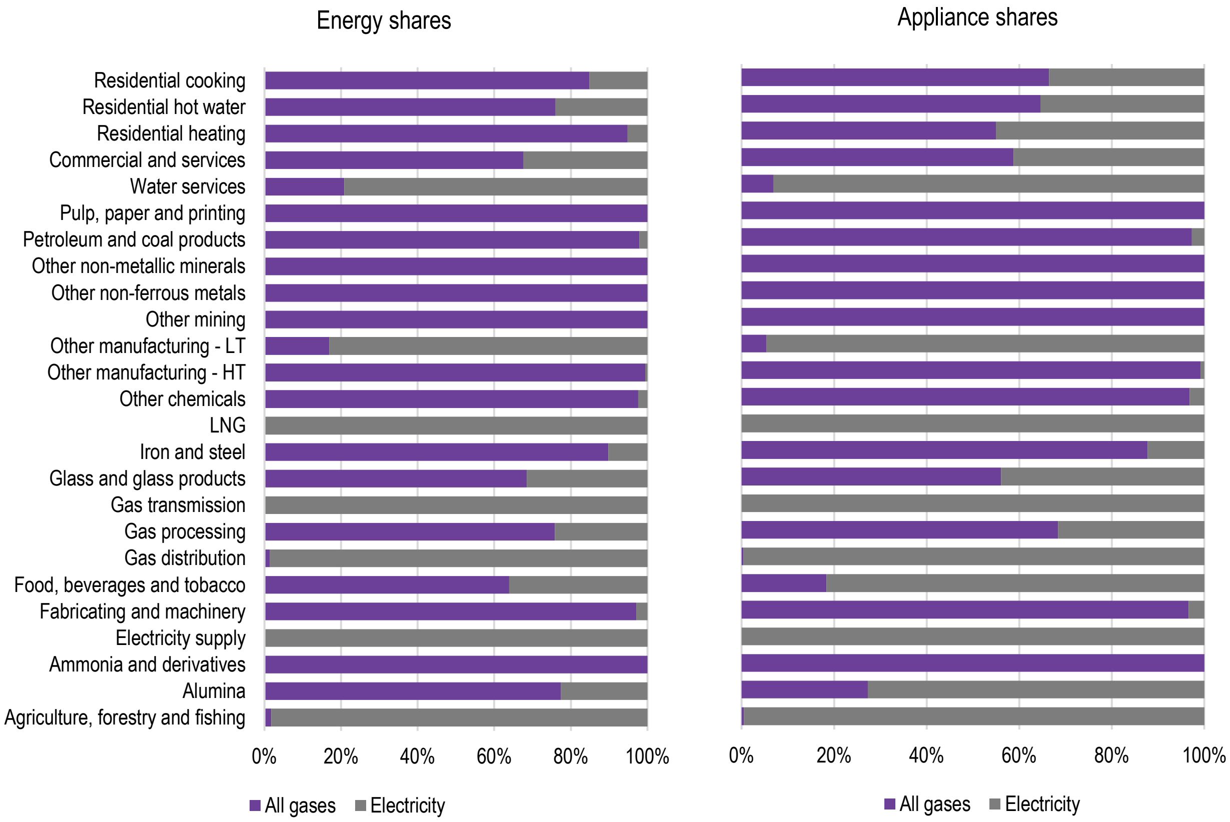
Figure 3.40 Renewable gas developed: Accelerated RGT scenario



Source: ACIL Allen Gas Transition Model

Figure 3.41 provides a breakdown of fuel use and appliance types by sector on a national level in 2050. Compared to the Theoretical Efficient Policy scenario (Figure 3.11), fuel mixes are similar, with a slight increase in the overall use of gaseous fuels and a slight decrease in the amount of electrification.

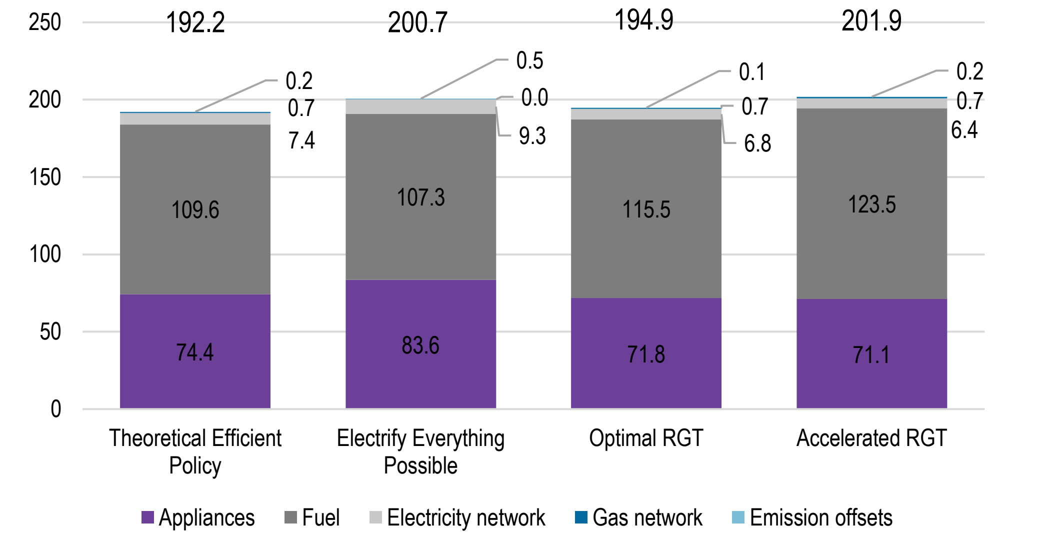
Figure 3.41 Energy and appliance shares by sector and fuel type in 2050: Accelerated RGT scenario



Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.42 compares the present value of costs in the Accelerated RGT scenario to the other policy scenarios. The accelerated development of renewable gas increases costs relative to the Theoretical Efficient Policy and Optimal RGT scenarios. The scenario has slightly higher total cost than the Electrify Everything Possible scenario, but when converted to a cost per unit of abatement to account for the slightly lower emissions in that scenario, the Accelerated RGT achieves slightly lower per unit abatement costs than the Electrify Everything Possible scenario – \$164/tonne CO_2-e compared to \$165/tonne CO_2-e. This indicates that adopting an accelerated emissions reduction approach through an RGT, that includes both electrification and renewable gas, can reduce emissions faster and at a comparable cost than an electrification-focused approach.

Figure 3.42 Present value of costs by category, 2025 to 2060, by policy scenario ($b)



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

3.5.1 RGT trajectory sensitivities

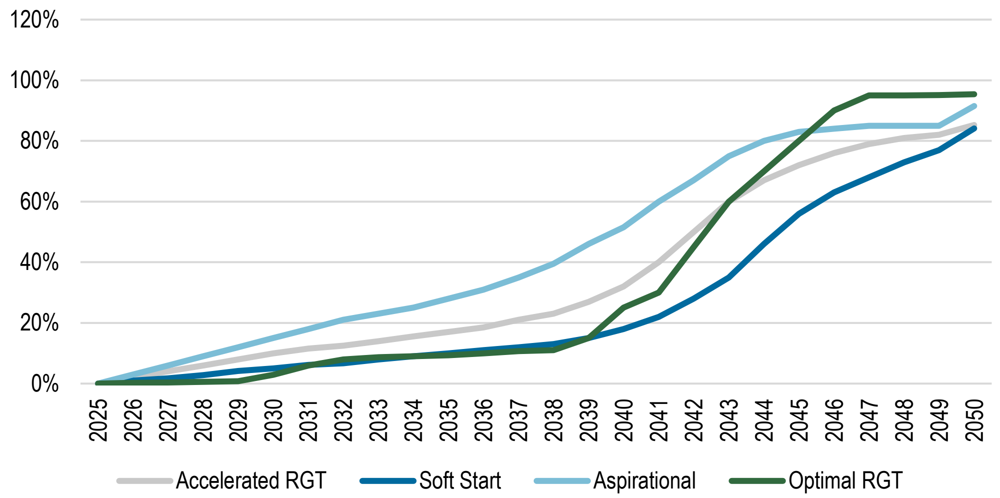
Comparing the Optimal RGT and Accelerated RGT scenarios demonstrates that accelerated renewable gas uptake through higher RGTs can increase abatement, albeit at higher average unit cost. To further explore the effect of variations in the speed of renewable gas uptake we explored two further sensitivities where we set the following minimum renewable gas constraints within the GTM to establish the following RGT uptake trajectories:

— A ‘Soft Start’ trajectory which utilises a diffusion of innovation S-Curve from 2025 to 2060, starting at 0% renewable gas in 2025 and ending at 85% in 2055

— An ‘Aspirational’ trajectory which increases linearly from zero 0 to 15% renewable gas in 2030 then utilises a diffusion of innovation S-Curve ending at 85% in 2047.

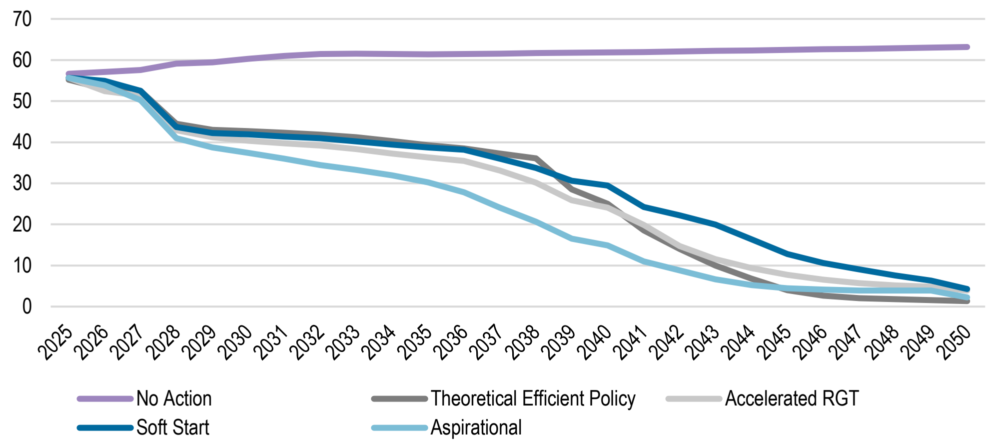
Figure 3.43 compares the targets under the ‘Soft Start’ and ‘Aspirational’ trajectories relative to the Optimal RGT and Accelerated RGT scenarios, and Figure 3.44 compares the emissions outcomes under these scenarios and sensitivities. As expected, the Aspirational trajectory reduces emissions faster than even the Accelerated RGT, whiles the Soft Start trajectory has higher emissions.

Figure 3.43 Renewable gas share of gaseous fuels, RGT sensitivities: Accelerated, Soft and Aspirational targets compared with Optimal RGT



Source: ACIL Allen Gas Transition Model

Figure 3.44 Emission outcomes under the RGT sensitivities (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

Whole-of-economy modelling 4

This chapter provides an overview of the approach used to model the broader economic impact of the gas transition scenarios using computable general equilibrium (CGE) modelling and presents the projected impacts.

4.1 Introduction

To provide information on the broader economic impacts on the Australian economy potentially arising from the large structural changes involved in achieving the gas transitions, ACIL Allen has undertaken CGE modelling using our *Tasman Global* model. It is a multi-sector dynamic model of the Australian and world economy that has been used for many similar modelling projects. An overview of the model is provided in Appendix F.

Transitioning today's natural gas using sectors to net zero emissions will require a wide range of capital and operating expenses across the economy. These include capital expenditure by businesses and households to replace appliances, and capital expenditure by energy supplying sectors to provide electricity or renewable gases to end-use sectors.

The estimated capital and operating expenses underlying each scenario along were used to inform the Tasman Global No Action and policy scenarios. The differences between the economic projections of the No Action and the various policy scenarios provide a forecast of the total economic impacts of each policy scenario.

CGE models produce a wide variety of economic metrics. The metrics reported in this case include:

— Real economic output (as measured by real Gross State Product (GSP) or Gross Domestic Product (GDP)) is defined as the sum of value added by all producers who are within the region/state, plus any product taxes (minus subsidies) not included in output. A positive deviation (i.e. increase) of real economic output from the No Action scenario implies that the proposed transition scenario will enable the economy to produce more real goods and services potentially available for consumption.

— Real income: In most CGE models, such as Tasman Global, the change in real income is a measure of the change in economic welfare of the residents of the region, state or country. The change in real income is equal to the change in real economic output plus the change in net foreign income transfers plus the change in terms of trade. In contrast to measures such as real economic output, real income accounts for any impacts of foreign ownership and debt repayments, as well as changes in the purchasing power of residents as a result of a project or policy.

— Employment and real wages impacts, with employment measured in terms of full-time equivalent (FTE) jobs.

4.1.1 Framework of analysis

The macroeconomic impacts of a policy, project or other activity can be estimated using a variety of economic analysis tools. The most common methods utilised are input-output (I-O) multiplier analysis and CGE modelling. The selection of the right tool is critical to the accuracy of the estimated impacts and depends upon the characteristics of the policy or project. Sometimes more than one tool may be required to provide a full picture of economic consequences.

By their nature, I-O multipliers and CGE models focus on 'market impacts' across the economy (that is, impacts on activities with observed market prices). Analysis of various 'non-market impacts', such as property right infringements, potential loss of biodiversity, changes in air quality or greenhouse gas emissions, social justice implications and so forth may also be relevant in assessing the full implications of a project or policy, but are not captured within I-O multipliers and CGE models. Such effects can be incorporated into a traditional CBA.

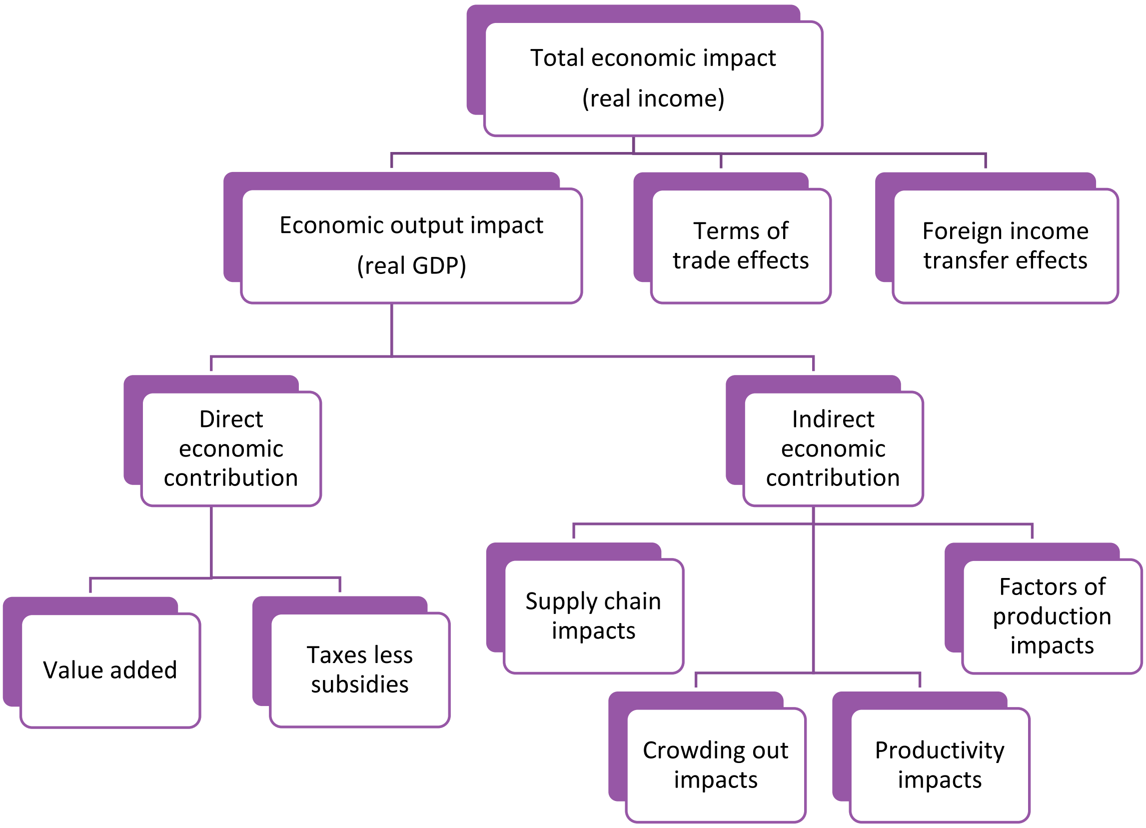
Fundamentally, although various aspects of a policy or project may be relevant to particular stakeholders—for example, the number of jobs created or the size of the investment expenditure—the key aggregate measure of the macroeconomic impact of a project or policy is the extent to which the total income of the economy has changed as a result of that policy or project. This is typically measured in terms of the change in real gross national disposable income (RGNDI), although real gross domestic product (GDP) and consumer surplus can also be important aggregate measures depending on the nature of the policy or project being analysed.

The main factors that need to be considered when analysing the macroeconomic impacts of a project or policy include:

— the direct and indirect contribution to the economy as a result of the activities associated with the project or policy
— any crowding out implications as resources are potentially diverted away from other productive activities to undertake the project or policy being analysed
— any productivity effects generated as a direct result of the policy or project activities – particularly any enduring productivity changes or productivity impacts on other activities not directly associated with the project or policy
— any changes to the factors of production in the economy
— any implications associated with changes in terms of trade or foreign income transfers
— the extent of any dynamic element to the size of any of the above effects (for example, associated with different phases of the project).

Figure 4.1 shows these components graphically. Some of these effects may be negligible while others may be significant. An understanding of the effects helps determine the most appropriate tool(s) for the analysis.

Figure 4.1 Estimating the macroeconomic impact of a project or policy



Note: In *Tasman Global*, the change in real income is equivalent to the change in equivalent variation – a standard economic measure of the change in consumer welfare resulting from exogenous shocks
Source: ACIL Allen

For many projects, static estimates of the direct economic contribution and of supply chain indirect economic contribution implications can be obtained using I-O multipliers. Estimating the size of other components using multiplier techniques is either not possible or very complex, as is estimating the economic impacts through time. In contrast, most CGE models can estimate all of the components shown in Figure 4.1 with dynamic CGE models able to estimate the impacts through time.

Given the substantial structural changes to the Australian economy associated with the energy transitions, CGE modelling has been chosen as the most appropriate tool to undertake the economic impacts assessment in this report.

4.1.2 The Tasman Global CGE model

Tasman Global is a large scale, dynamic CGE model of the world economy that has been developed in-house by ACIL Allen Consulting. Tasman Global is a powerful and effective tool for undertaking economic analysis at the regional, national and global levels.

CGE models mimic the workings of the economy through a system of interdependent behavioural and accounting equations which are linked to an I-O database. These models provide a representation of the whole economy, set in a national and international trading context. Starting with individual producers and consumers, the model builds up the economy through the demands and production from each individual actor in the face of interlinked markets. When an economic "shock" or disturbance is applied to a model, each of the markets adjusts according to a set of behavioural parameters which are underpinned by economic theory. The generalised nature of

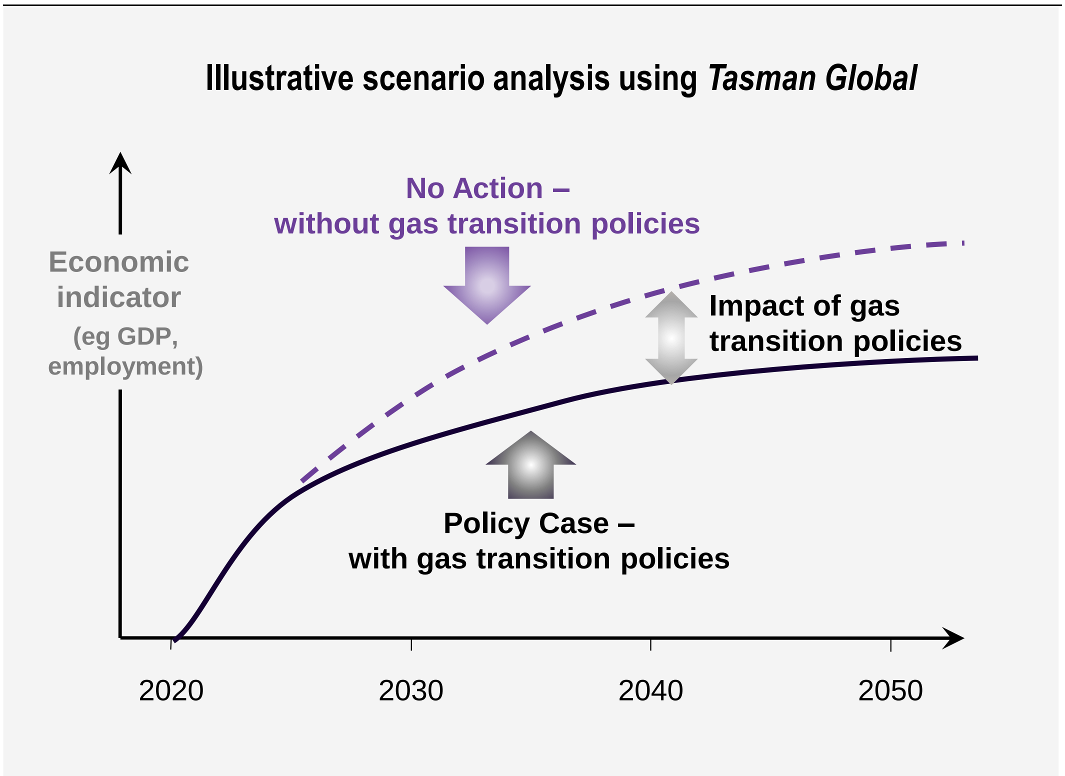
CGE models enable a much broader range of analysis to be undertaken (generally in a more robust manner) compared to I-O multiplier techniques.

A more detailed discussion of Tasman Global and its operation is provided in Appendix F.

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before a policy change and one following). A dynamic model such as Tasman Global is beneficial when analysing issues where both the timing of impacts and the adjustment path that economies follow are relevant in the analysis.

In applications of the Tasman Global model, a baseline simulation (in this exercise, the No Action scenario) provides a 'business-as-usual' scenario against which to compare the results of various simulations. The baseline provides projections of growth in the absence of the policies being considered. It therefore provides the base line projections of GDP, population, labour supply, industry output, and other relevant measures, and provides projections of endogenous variables such as productivity changes and consumer preferences. The policy scenarios assume all productivity improvements, tax rates and consumer preferences change as per the No Action scenario but also includes the proposed policies. The alternative scenarios result in different projections of the economy, and the net impacts of the policies can be calculated as the differences, for each relevant measure, between each policy case and the baseline (see Figure 4.2).

Figure 4.2 Illustrative scenario analysis using *Tasman Global*



Note: In practice, impacts could be negative, positive, neutral or a mixture

Source: ACIL Allen

4.2 Key assumptions

4.2.1 Constrained labour market

A key issue when estimating the impact of a project is determining how the labour market will clear.[19] As discussed in Section D.6, in the standard Tasman Global framework increases in the demand for labour in any state induced by the Project can be met by three mechanisms: increasing migration from the Rest of Australia; increasing participation rates and/or average hours worked; and by reducing the unemployment rate. In the standard model framework, the first two mechanisms are driven by changes in the real wages paid to workers in the local region while the third is a function of the additional labour demand relative to the baseline.

It should be noted that this analysis does not assume any change in net foreign migration as a result between the policy cases and the baseline.

4.3 Measures of macro-economic impacts

One of the most commonly quoted macroeconomic variables at a national level is real gross domestic product (GDP), which is a measure of the aggregate output generated by an economy over a given period of time (typically a year). GDP may be calculated in different ways:

— On the expenditure side by adding together total private and government consumption, investment and net trade.

— On the income side as the sum of returns to the primary factors of production (labour, capital and natural resources) employed in the national economy plus indirect tax revenue.

The regional level equivalent to GDP is gross regional product (GRP) – at the state or territory level it is called gross state product or gross territory product (GSP or GTP, respectively). To reduce the potential confusion with the various acronyms, the term **economic output** has been used in the discussion of the results presented in this chapter.

These measures of the real economic output of an economy should be distinguished from measures of the economy's real income, which provide a better indication of the economic welfare of the residents of a region. It is possible for real economic output to increase (that is, for GDP to rise) while at the same time real income (economic welfare) declines. In such circumstances, people and households would be worse off despite economic growth.

In *Tasman Global*, the relevant measure of real income at the national level is real gross national disposable income or RGNDI as reported by the Australian Bureau of Statistics.

As shown in Figure 4.1, the change in a region's real income as a result of a new project is the change in real economic output plus the change in net external income transfers plus the change in the region's terms of trade (which measure the change in the purchasing power of the region's exports relative to its imports).Changes in the terms of trade can have a substantial impact on residents' welfare independently of changes in real economic output.

In global CGE models such as *Tasman Global*, the change in real income is equivalent to the change in consumer welfare using the equivalent variation measure of welfare change resulting

[19] As with other CGE models, the standard assumption within *Tasman Global* is that all markets clear (i.e. demand equals supply) at the start and end of each time period, including the labour market. CGE models place explicit limits on the availability of factors and the nature of the constraints can greatly change the magnitude and nature of the results. In contrast, most other tools used to assess economic impacts, including I-O multiplier analysis, do not place constraints on the availability of factors. Consequently, these tools tend to overestimate the impacts of a project or policy.

from exogenous shocks. Hence, it is valid to say that the projected change in real income (from *Tasman Global*) is also the projected change in consumer welfare.

4.4 Economic modelling results

Undertaking a large scale transition of the Australian energy system will result in a range of macroeconomic impacts beyond those analysed in the cost benefit analysis. Some of these will be positive (such as energy efficiency improvements or reductions in gas purchases resulting in improving the competitiveness of Australian businesses or improving the cost of living for residents), while some will be negative (such as increased electricity purchases reducing the competitiveness of Australian businesses or increasing the cost of living for residents). Further, the relative local content of alternative investment or consumption options can also result in additional second or third round effects of the core drivers underlying each scenario. Indeed, in each scenario the complexities associated with the energy transition means that there are generally a wide range of competing positives and negatives for businesses and residents in any particular year meaning that it is difficult to disentangle individual impacts. In such circumstances, CGE models are generally the preferred tool for estimating the net macroeconomic impacts. This section presents the projected macroeconomic impacts using CGE modelling.

4.4.1 Real economic output and real income

As discussed in section 4.3, real economic output is the sum of value added by all producers in the relevant region/state, plus any product taxes (minus subsidies) not included in output. When calculated at a national level, this is referred to as gross domestic product (GDP), and as gross state product (GSP) at the state level.

In contrast, real income is a measure of the ability to purchase goods and services, adjusted for inflation, with the change in real income equal to:

— the change in real economic output (GDP/GSP)

— plus the change in net foreign income transfers

— plus the change in terms of trade.

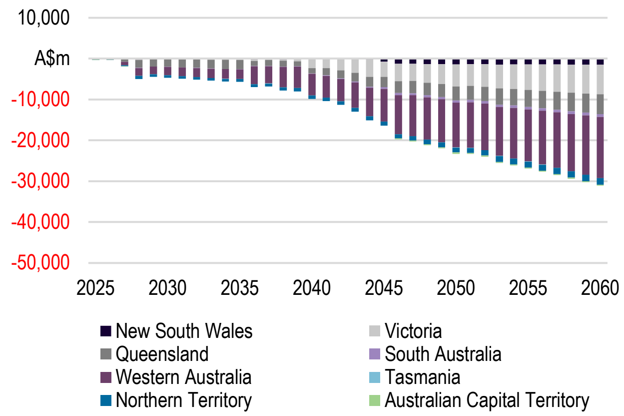
While the change in real economic output (GSP) is a useful indicator, real income provides a better measure of the welfare impact that changes in these aggregates have on people living in a region. A rise in real income indicates a rise in the capacity for current consumption, but also an increased ability to accumulate wealth in the form of financial and other assets.

Figure 4.3 shows the estimated annual change in real GSP for each state under each scenario, relative to the No Action scenario, while

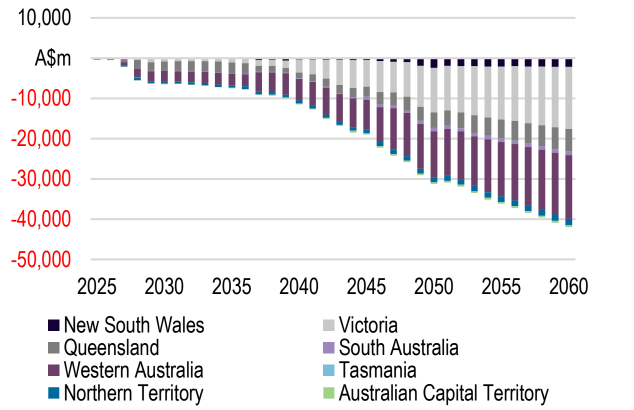
Table 4.1 presents the present value change over the period 2025 to 2060 inclusive. As we are comparing to a No Action scenario with no climate action, the changes in real economic output are generally negative.

Figure 4.3 Annual change in real economic output under each scenario relative to the No Action scenario ($m)

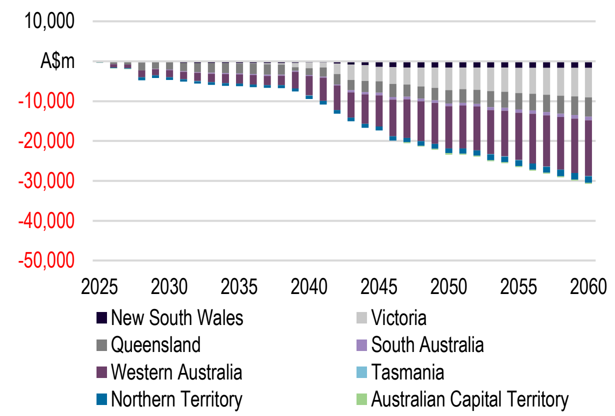
A. Theoretical Efficient Policy



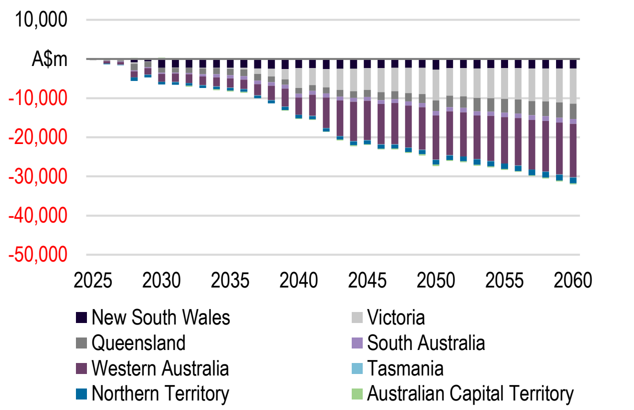
B. Electrify Everything Possible



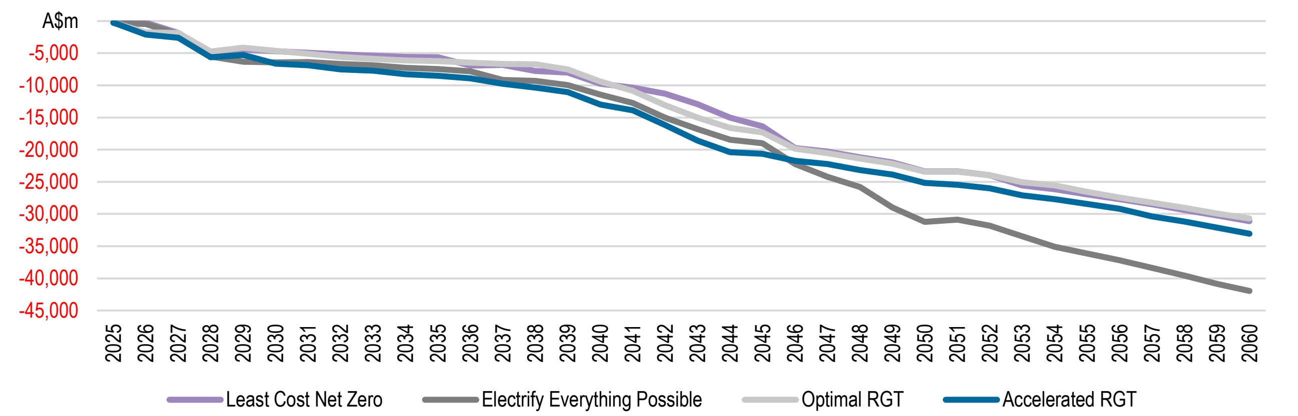
C. Optimal RGT



D. Accelerated RGT



E. Australia



Note: present value calculated using a 7% discount rate. Real economic output is commonly referred to as gross domestic product (GDP) at the national level, or gross state product (GSP) at the state level.

Source: ACIL Allen Tasman Global modelling

Table 4.1 Present value of change in real economic output by state under each scenario, relative to the No Action scenario

	Theoretical Efficient Policy	Electrify Everything Possible	Optimal RGT	Accelerated RGT
	$m	$m	$m	$m
New South Wales	-4,188	-6,243	-7,563	-20,449
Victoria	-20,140	-41,277	-18,961	-20,555
Queensland	-26,137	-30,070	-29,809	-27,352
South Australia	-2,023	-3,064	-3,633	-6,756
Western Australia	-58,550	-62,277	-53,998	-62,712
Tasmania	-176	-66	-157	-523
Northern Territory	-9,409	-8,842	-9,676	-9,537
Australian Capital Territory	-465	-2,634	-368	-2,155
Australia (GDP)	**-121,088**	**-154,473**	**-124,164**	**-150,039**
Change relative to Theoretical Efficient Policy	**0**	**-33,386**	**-3,077**	**-28,951**

Note: present value calculated using a 7% discount rate

Source: ACIL Allen Tasman Global modelling

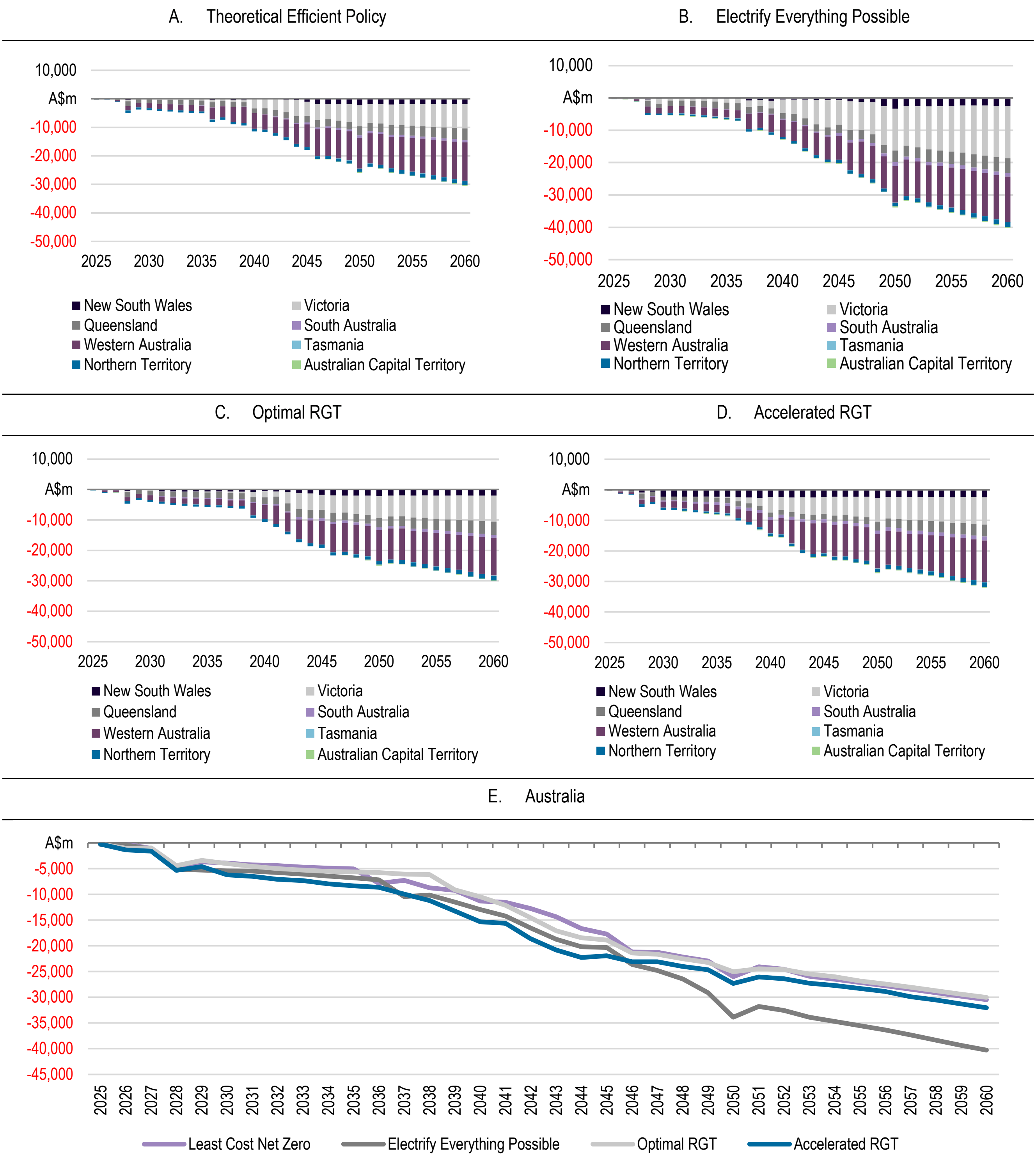
There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, energy prices and volumes, and efficiency changes. In total, over the period to 2060 the present value of the reduction in Australia's GDP relative to the No Action scenario (using a 7% discount rate) is:

— –$121.1 billion under the Theoretical Efficient Policy scenario
— –$154.5 billion under the Electrify Everything Possible Scenario
— –$124.1 billion under the Optimal RGT Scenario
— –$150.0 billion under the Accelerated RGT Scenario.

Each policy scenario reduces GDP relative to the No Action scenario because decarbonising the gas sector increases overall energy and appliance costs and reduces economic productivity. However, this views changes to Australia's gas sector in isolation from broader global efforts to reduce emissions, which will deliver economic benefits through reduced climate impacts on sectors such as agriculture, infrastructure and health. Further, the No Action scenario is inconsistent with national, state and territory government commitments to achieve net zero emissions by 2050, and therefore is not credible to assume that Australian governments will avoid transition costs in the gas sector at the expense of these overarching objectives – rather the objective of this modelling is primarily to identify the most efficient ways to achieve net zero. Therefore, these estimates of economic costs should be used to compare scenarios, rather than assess the overall costs and benefits of reducing emissions in Australia's gas sector as part of a wider global effort. Given this, the modelling demonstrates that policy options with lower direct gas sector costs such as the Theoretical Efficient Policy and Optimal RGT scenarios also translate to lower whole-of-economy costs. For example, adopting the Optimal RGT policy rather than an electrification-focused approach implied by the Electrify Everything Possible scenario would increase Australia's gross domestic product in the order of $30 billion (in present value terms) over the transition.

Figure 4.4 shows the estimated annual change in real income for each state under each scenario, relative to the No Action scenario, while Table 4.2 presents the present value of the total change over the period 2025 to 2060 inclusive.

Figure 4.4 Annual change in real economic income under each scenario relative to the No Action scenario ($m)



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Tasman Global modelling

Table 4.2 Present value of change in real income under each scenario by state, relative to the No Action scenario

	Theoretical Efficient Policy	Electrify Everything Possible	Optimal RGT	Accelerated RGT
	$m	$m	$m	$m
New South Wales	-6,794	-9,013	-10,235	-24,198
Victoria	-26,575	-48,103	-25,274	-29,662
Queensland	-22,443	-25,290	-24,724	-20,716
South Australia	-2,592	-3,777	-4,549	-8,427
Western Australia	-55,090	-57,655	-49,644	-58,179
Tasmania	-321	-232	-290	-718
Northern Territory	-9,604	-8,904	-9,718	-9,457
Australian Capital Territory	555	-1,217	619	-1,043
Australia	**-122,863**	**-154,191**	**-123,816**	**-152,401**
Change relative to Theoretical Efficient Policy (Australia)	0	-31,328	-952	-29,537

Note: present value calculated using a 7% discount rate
Source: ACIL Allen Tasman Global modelling

In terms of the change in Australia's real income, the cumulative difference relative to the No Action scenario is projected to be:

- –$122.9 billion under the Theoretical Efficient Policy scenario
- –$154.2 billion under the Electrify Everything Possible Scenario
- –$123.8 billion under the Optimal RGT Scenario
- –$152.4 billion under the Accelerated RGT Scenario.

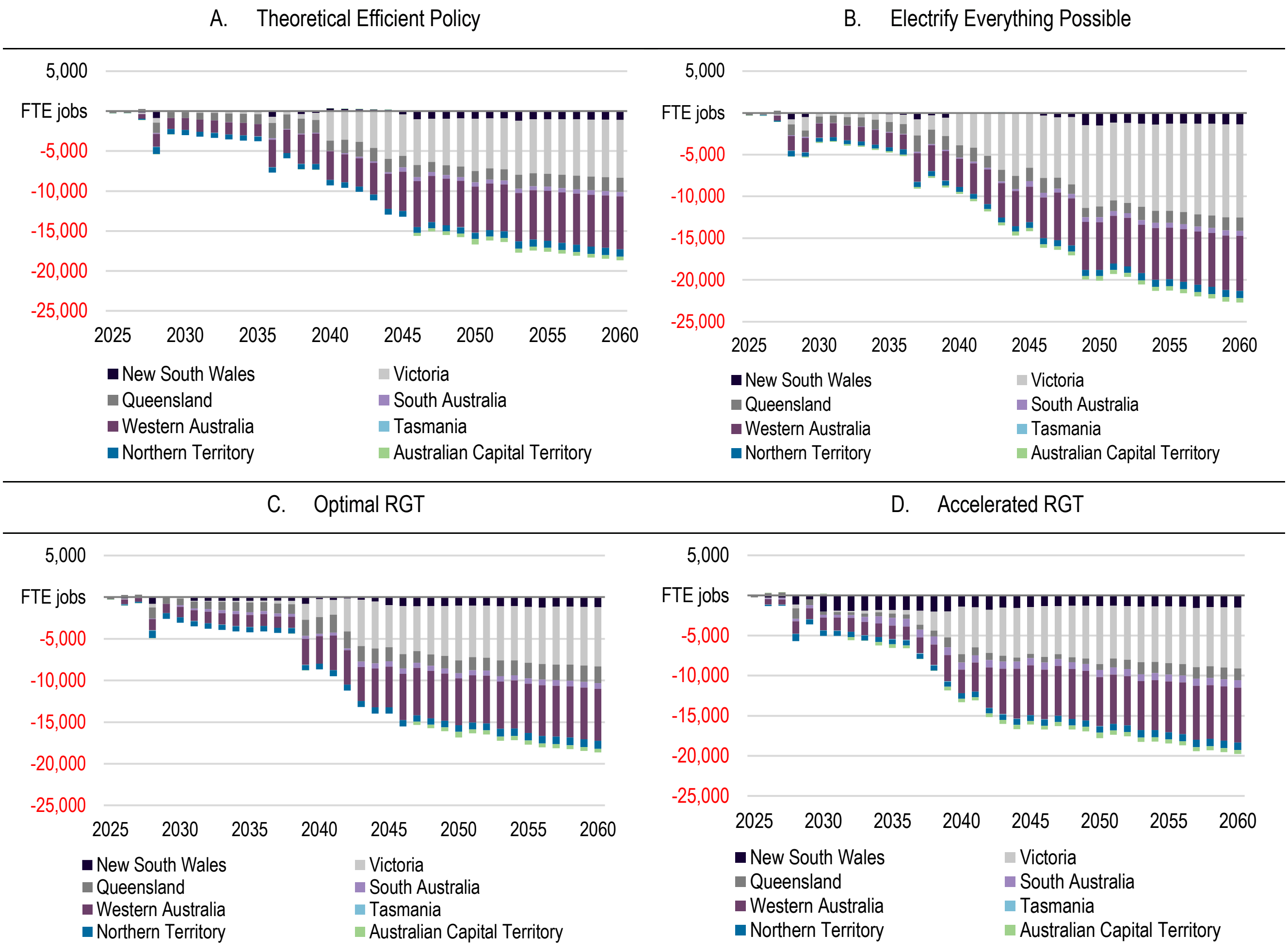
As for GDP, each policy scenario reduces real economic income relative to the No Action scenario because decarbonising the gas sector causes a negative shock to economic productivity. However, as the No Action scenario is inconsistent with national, state and territory government commitments to achieve net zero emissions by 2050, these estimates of changes to real economic income should be used to compare scenarios, rather than assess the overall costs and benefits of reducing emissions in Australia's gas sector.

Policy options with lower direct gas sector costs such as the Theoretical Efficient Policy and Optimal RGT scenarios also translate to higher real economic income. For example, adopting the Optimal RGT policy rather than an electrification-focused approach implied by the Electrify Everything Possible scenario would increase Australia's real income in the order of $30 billion (in present value terms) over the transition.

4.4.2 Employment

Figure 4.5 presents the annual change in employment under each scenario relative to the No Action scenario.

Figure 4.5 Annual change real employment under each scenario relative to the No Action scenario



Source: ACIL Allen Tasman Global modelling

Table 4.3 Cumulative and annual average change in employment under each scenario by state, relative to the No Action scenario

	Theoretical Efficient Policy	Electrify Everything Possible	Optimal RGT	Accelerated RGT
Cumulative (2025-2060)	Employee years	Employee years	Employee years	Employee years
New South Wales	-17,001	-21,434	-24,485	-51,307
Victoria	-129,622	-192,983	-124,798	-147,565
Queensland	-48,298	-45,052	-50,221	-29,349
South Australia	-9,703	-11,468	-15,745	-26,800
Western Australia	-141,707	-139,624	-131,904	-148,820
Tasmania	-324	288	-53	-806
Northern Territory	-24,705	-22,145	-25,204	-24,890
Australian Capital Territory	-7,106	-11,381	-6,587	-12,761
Australia	**-378,465**	**-443,799**	**-378,997**	**-442,299**
Change relative to Theoretical Efficient Policy (Australia)	**0**	**-65,333**	**-531**	**-65,553**
Annual average	FTE jobs	FTE jobs	FTE jobs	FTE jobs
New South Wales	-472	-595	-680	-1,425
Victoria	-3,601	-5,361	-3,467	-4,099
Queensland	-1,342	-1,251	-1,395	-815
South Australia	-270	-319	-437	-744
Western Australia	-3,936	-3,878	-3,664	-4,134
Tasmania	-9	8	-1	-22
Northern Territory	-686	-615	-700	-691
Australian Capital Territory	-197	-316	-183	-354
Australia	**-10,513**	**-12,328**	**-10,528**	**-12,286**
Change relative to Theoretical Efficient Policy (Australia)	**0**	**-1,815**	**-15**	**-1,773**

Source: ACIL Allen Tasman Global modelling

As for GDP and real economic income, decarbonising the gas sector causes a negative shock to economic productivity and so reduces employment relative to the No Action scenario. However, as the No Action scenario is inconsistent with national, state and territory government commitments to achieve net zero emissions by 2050, these estimates of changes to employment should be used to compare scenarios, rather than assess the overall costs and benefits of reducing emissions in Australia's gas sector. Policy options with lower direct gas sector costs such as the Theoretical Efficient Policy and Optimal RGT scenarios have smaller effects on employment, that is, higher employment than under the Electrify Everything Possible and Accelerated RGT scenarios.

Appendices

Wholesale gas market modelling A

This appendix outlines the key gas market assumptions, modelling methodology, and results that were used to inform the transition model.

A.1 Market assumptions

A.1.1 East Coast Gas Market

ACIL Allen was recently engaged by AEMO to undertake price projections to inform the Annual Inputs and Assumptions Report (IASR) and Gas Statement of Opportunity for 2024 within the East Coast Gas Market (ECGM) and Northern Territory. As a part of this work ACIL Allen aligned key gas market assumptions within our proprietary modelling software GasMark with AEMO's assumptions. As such our standard models which form the starting point for our modelling work, are well aligned with AEMO.

To define the resource cost for the ECGM ACIL Allen built on the assumptions used by AEMO to clearly define 2 scenarios that represent a Low and a High scenario for gas consumption. The key aspects of these scenarios are contained in Table A.1.

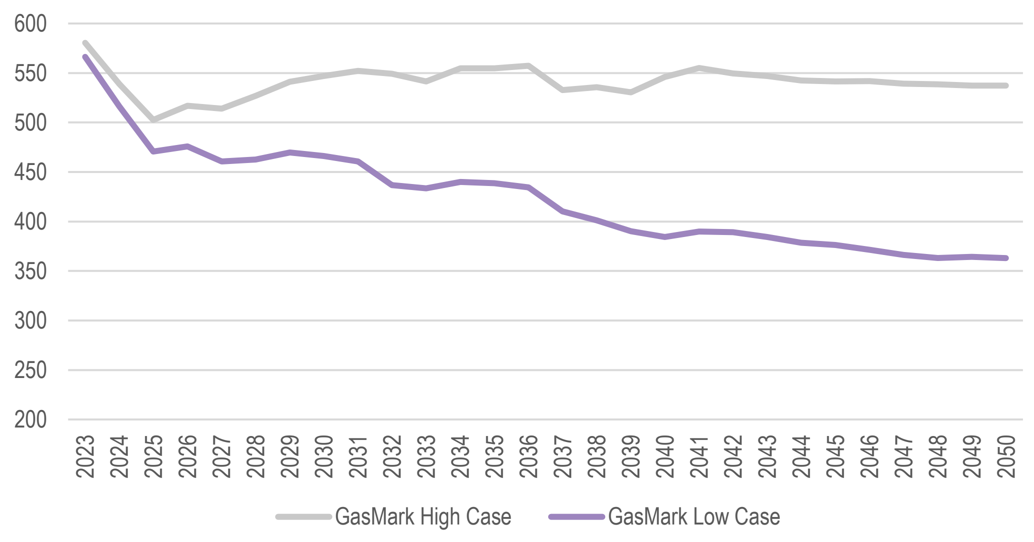
Table A.1 ECGM Model Assumptions

Assumption	Low Case	High Case
Demand	Orchestrated Scenario Demand from 2023 GSOO	Demand without impact of electrification of gas load
Reserves and Resources	2P reserves + 2C resources Broadly Aligned with 2023 GSOO and Industry	2P reserves + 2C resources Broadly Aligned with 2023 GSOO and Industry
Production Costs	Aligned with 2023 GSOO and industry	Aligned with 2023 GSOO and industry
New Gas Supply NSW	Narrabri proceeds from 2026	Narrabri proceeds from 2026
New Gas Supply VIC	**Gippsland** – GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** – Enterprise in 2024 and Thylacine from 2023 **Bass** – Trefoil is developed	**Gippsland** – GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** – Enterprise in 2024 and Thylacine from 2023 **Bass** – Trefoil is developed
New Gas Supply QLD	Bowen Basin – Mahalo project (Santos)	Bowen Basin – Mahalo project (Santos)
New Gas Supply SA	No New Projects	No New Projects
New Gas Supply NT	Beetaloo – long term supply capacity of 50PJ available for ECGM	Beetaloo – long term supply capacity of 100PJ available for ECGM

Assumption	Low Case	High Case
Pipeline Developments	According to 2023 GSOO	According to 2023 GSOO Plus significant additional expansions to SWQP, MSP, and EGP to transport northern supply south to meet demand.
Pipeline Expansion Costs	N/A	$60,000/inch km at 8%/annum for 40yrs
Pipeline Tariffs	According to 2023 GSOO	According to 2023 GSOO
Global Long Term Oil Price	Long term US$65 per barrel	Long term US$65 per barrel
QLD LNG Exports	ACIL Allen Reference Case Assumptions	ACIL Allen Reference Case Assumptions

Figure A.1 displays the demand assumptions for the two scenarios. The Low case (AEMO's Orchestrated Scenario) assumes a considerable reduction in gas consumption over the projection period. This is primarily due to electrification driven demand destruction, and fuel switching as part of the push for net zero by 2050 and other interim climate objectives. The high case presents an alternate view where business as usual prevails and gas usage does not decrease over time. As discussed further in the results section, the sustained high consumption levels in the high case have implications with respect to resource costs when field depletion and supply dynamics to meet the demand are considered. These factors are what is important when comparing the cost of sustaining the gas industry at such a level, and form part of the resource cost formula.

Figure A.1 ECGM gas demand, by case (PJ)



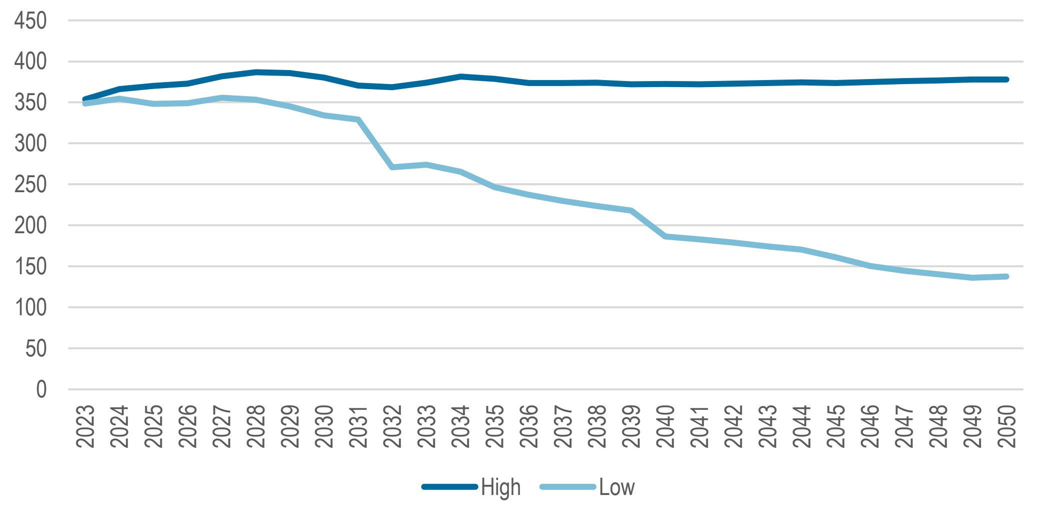
A.1.2 West Coast Gas Market

The West Coast Gas Market (WCGM) is at a similar but less extreme tipping point to the ECGM with comparable pressure to electrify and decarbonise, however these forces are muted by the gas reservation policy which has to date ensured price and supply security. The continuation of this supply/demand balance is contingent on the timeline of key Greenfield LNG fields and onshore domestic gas development. As in the ECGM, ACIL Allen has defined a high and low scenario for the WCGM. The low case in this instance follows ACIL Allen's view of a 'most likely' demand scenario given electrification of industry groups within the Western Australian market. The High case again represents a situation where business as usual gas consumption prevails and extends throughout the projection period, allowing the cost of retaining gas to be properly examined. The key aspects of these scenarios are contained in Table A.2, and Figure A.2 displays the demand assumptions for the two scenarios.

Table A.2 WCGM Model Assumptions

Assumption	Low Case	High Case
Demand	ACIL Allen Reference Case	Demand without impact of electrification of gas load
Reserves and Resources	2P reserves + 2C resources Broadly Aligned with 2022 GSOO WA and Industry	2P reserves + 2C resources Broadly Aligned with 2022 GSOO WA and Industry
Production Costs	Broadly Aligned with industry	Broadly Aligned with industry
New Gas Supply Onshore	West Erregulla from 2025, Lockyer Deep from 2026	As in low case
New Gas Supply Offshore Domestic	Corvus by 2028	Corvus by 2028
New Gas Supply Offshore Domestic Gas Obligation	Scarborough by 2027	Scarborough by 2027, Browse by 2032
Pipeline Developments	Not required	Not required
Pipeline Expansion Costs	N/A	N/A
Pipeline Tariffs	Broadly Aligned with industry	Broadly Aligned with industry
Global Long Term Oil Price	Long term US$65 per barrel	Long term US$65 per barrel
LNG Exports	ACIL Allen Reference Case Assumptions	ACIL Allen Reference Case Assumptions

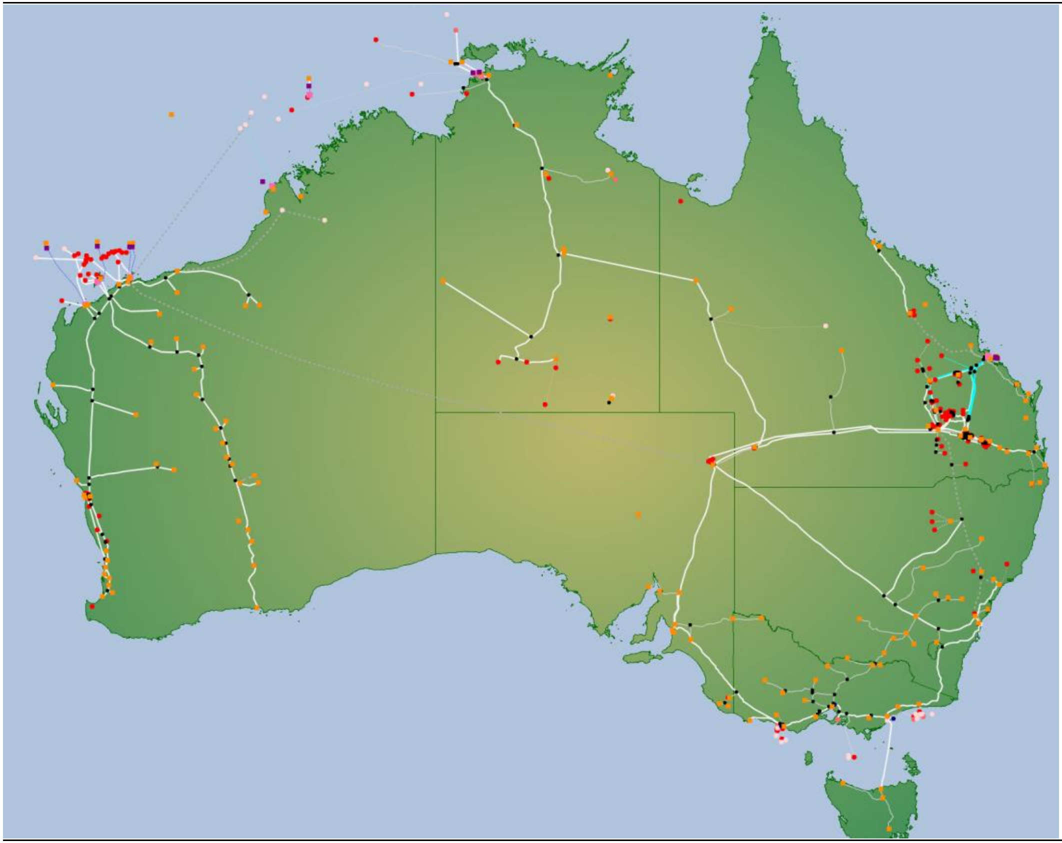
Figure A.2 WCGM demand, by case (PJ)



A.2 GasMark modelling

ACIL Allen uses our in-house market modelling software ‘GasMark Global’ to generate projections of future supply demand balance and estimate wholesale gas prices. GasMark operates as a partial spatial equilibrium model, representing the market as a set of consuming or producing nodes connected via a network of pipelines or LNG shipping elements. The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. GasMark contains a detailed representation of the of the entire Australian gas market topology as shown in Figure A.3 below.

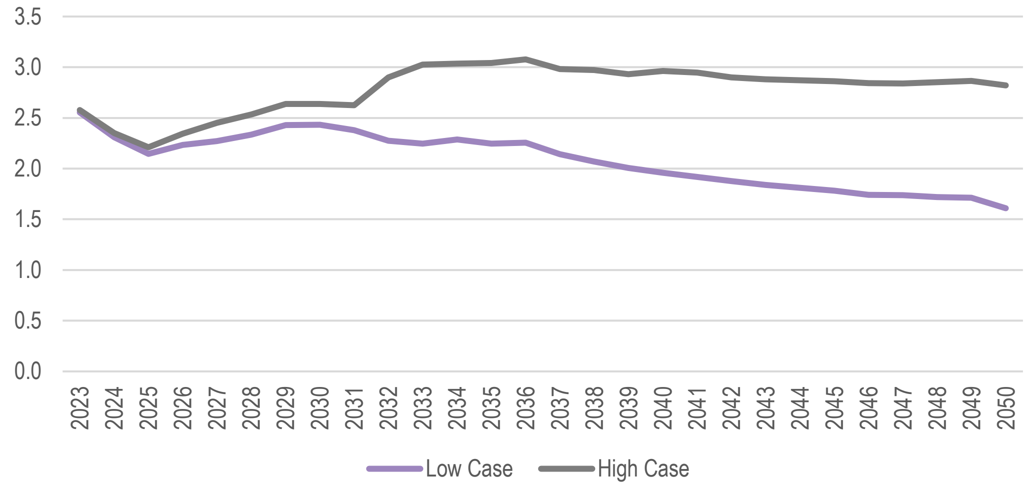
Figure A.3 GasMark network topology for the Australian gas market



A.3 Results

Supply dynamics within the east coast gas market are in the midst of a fundamental shift. Southern production is declining and incrementally being replaced by gas sourced from Queensland’s LNG-dominated coal seam gas fields. This trend is set to continue over the projection period, and when paired with AEMO’s electrification assumptions, the system manages to tightly avoid short falls and price escalation. This is the story in the Low case. The high case however sees a more rapid depletion of southern supply and thus a much heavier reliance on northern gas production, necessitating major pipeline expansion to avoid shortfalls. Under the high case, as mature and prospective fields are depleted, the cost of production slowly escalates as the cheaper reserves are depleted first. These dynamics when combined define the resource cost for each scenario.

Figure A.4 ECGM annual resource cost, by case (real 2023 $billion)



The resource cost as presented here is the sum of the levelized production cost at the current production tranche per field by production volume per field, plus 10% of pipeline tariff revenue[20] plus annuity payments to support pipeline expansions as required.

Expressed as an equation as follows.

$$ResourceCost = \sum(LevelizedProductionCost \times \text{ProductionVolume}) + (0.1 \times \sum \text{PipelineTariff revenue}) + \text{PipelineExpansionAnnuity}$$

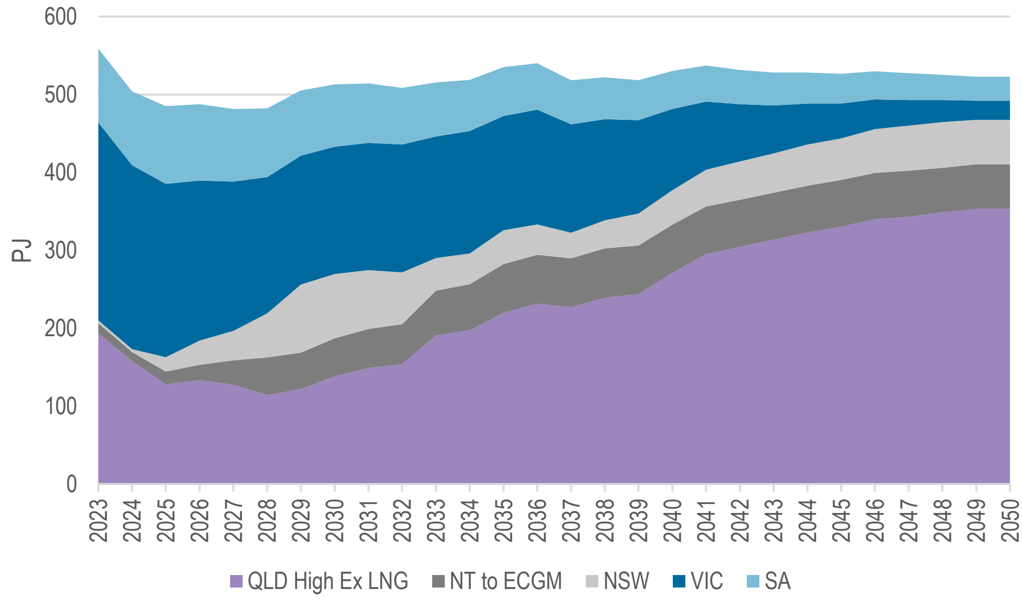
GasMark contains the cost of production expressed in terms of the levelized production cost of the current tranche of development per field; thus, distilling all associated production capital and operational investments/costs into a $/GJ figure per field tranche.

The High and Low cases consistently exhibit a significant separation in resource cost from early in the projection period. This separation widens significantly during the early 2030s due to the necessary expansion of key pipeline infrastructure to facilitate higher capacity delivery of northern gas to southern markets. Modelling projects it is necessary to build out an additional 400 TJ/day capacity at the SWQP and MSP pipeline systems, as well as an additional 140 TJ/day along the EGP.

Figure A.5 shows how the share of production by state jurisdiction evolves over time within the high case. This figure clearly illustrates the challenge that supplying a high gas consumption scenario and the justification for pipeline expansion projects under this scenario.

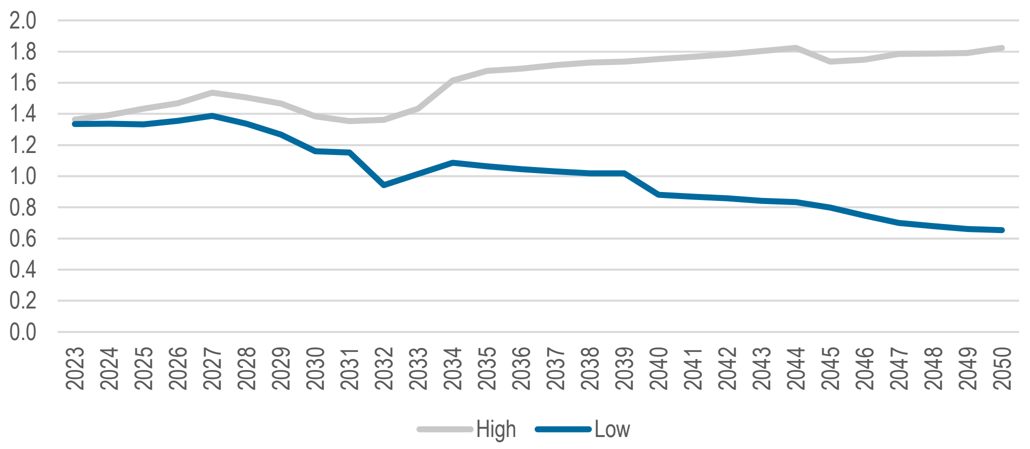
[20] Reflecting a high-level assessment of variable and operating costs for transmission pipelines as a proportion of the headline tariffs.

Figure A.5 ECGM gas production, by state



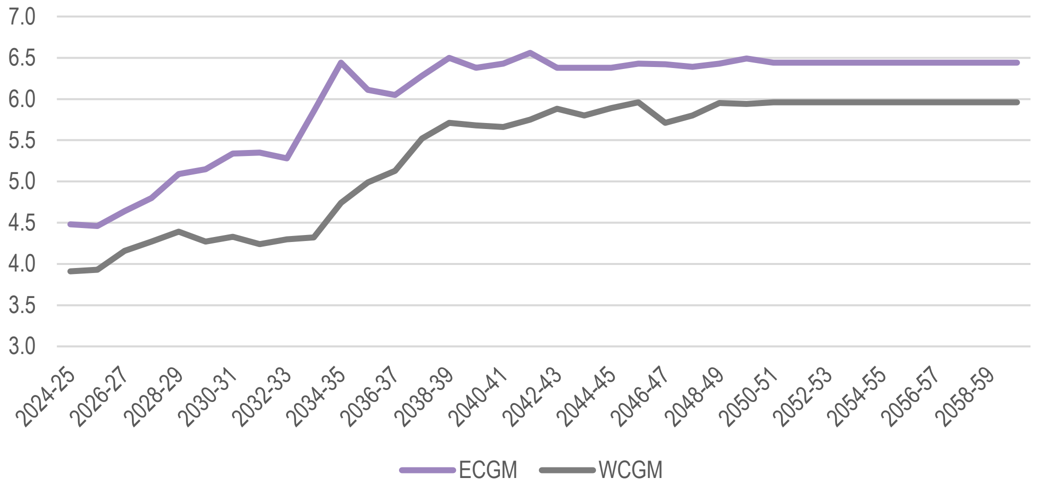
Resource costs in the WCGM diverge significantly between the high and low cases (Figure A.6), which is similar to the high-level result for the ECGM. However, this divergence occurs for different reasons in the two markets. Since pipelines are not constrained in WA, and there is no expected change to the geographic supply origin of gas as in the ECGM, there is not expected to be any additional pipeline capital cost to retaining gas consumption at current levels over the projection period. In the case of the WCGM, the driving factor in escalating the total resource cost for the high case is the underlying changes in cost of production as low-cost fields are depleted and new higher cost fields are added.

Figure A.6 WCGM resource cost, by case ($billion)



For use in the transition model, the total resource cost was converted back into a homogenised fuel cost. For the high cases of the ECGM and WCGM respectively the yearly fuel prices (contained in the figure below) formed the inputs for the transition model.

Figure A.7 Resource cost per unit of gas production, by market ($/GJ)



Wholesale electricity market modelling

B

This appendix outlines the key electricity market assumptions, modelling methodology, and results that were used to inform the transition model.

B.1 Market assumptions

B.1.1 National Electricity Market

Cost inputs for the NEM have utilised AEMO's Plexos modelling as part of the 2022 ISP Step Change scenario. Load-weighted prices from the LT planning model were extracted and these used as variable fuel resource costs for gas-based appliances.

As the Step Change scenario operates under a fixed emissions budget, any incremental demand has zero net emissions and the prices utilised reflect the need for firmed zero emission generation to meet incremental demand stemming from electrification.

B.1.2 Western Australian Wholesale Electricity Market

ACIL Allen has developed an updated market outlook of the WEM – the Reference case projection. The Reference case incorporates the best information available to ACIL Allen at the time that the case is developed and reflects current market conditions including any recent changes such as (but not limited to):

— new supply and retirements
— fuel costs
— demand
— generator investment costs
— government policy.

Assumptions utilised in the Reference case generally reflect a mid-case view. For example, we adopt forecast P50 peak demand and energy under the 2023 ESOO Central scenario, projected mid-case gas prices from our in-house gas market model (*GasMark*), and generator investment costs under the 2023 IASR assumptions Global NZE by 2050 scenario.

All assumptions used in the modelling are taken from publicly available or in-house information and databases maintained by ACIL Allen. The Reference case is intended to reflect a median or 50th percentile view and was current as at October 2023.

Table 1.4 Overview of WEM Reference case assumptions

Assumption	Details			
Macro-economic variables	Exchange rate of AUD to USD converging to 0.75 AUD/USD. Inflation of 2.5 per cent per annum. The brent crude oil price is assumed to converge from current levels to USD65/barrel by the mid-2020s and remain at this level in the long-term.			
Electricity demand	**Underlying demand** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario (energy and POE50 peak demand).	**Rooftop PV** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario, which extends to 2032 and ACIL Allen extrapolates this though to 2050.	**Behind-the-meter BESS** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario, which extends to 2032 and ACIL Allen extrapolates this through to 2050.	**Electric vehicles** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario, which extends to 2032 and ACIL Allen extrapolates this through to 2050. Assumed charging profiles are a blend of three charging behaviours that changes over time as charging infrastructure is developed. Profiles include an overnight charging profile, a daytime charging profile and a late evening/convenience charging profile.
State-based policies	In June 2022, the WA Government announced the accelerated closure of the Synergy coal fleet in response to the challenge from incorporating rooftop solar PV and the desire to decarbonise the electricity grid at a faster rate. The revised closure schedule is: Muja C Unit 5 late 2022 (no change); Muja C Unit 6 in 2024 (no change); Collie in late 2027; Muja D in late 2029. As part of these changes, the State Government has also committed to not commission any new natural gas-fired power stations on the SWIS after 2030. This closure schedule has been incorporated into the Reference case however the modelling still allows for the entry of gas-fired generation post 2030. Bluewaters is assumed to close by 2029-30, on the assumption that the Griffin coal mine, which supplies coal to Bluewaters, ceases operations.			
Federal greenhouse gas emission policies	Economy-wide 43 per cent reduction in GHG emissions below 2005 levels by 2030 and a net zero emissions target by 2050. Retention of the LRET in its current form to 2030 is assumed, with no extension beyond 2030.			
Electricity supply (beyond new supply driven by state based schemes)	**Assumed new entry and closures** Committed or likely committed generator closures included where the closure has been announced by the participant, including: Muja C unit 6 in late 2024	**Assumed new entry and closures** Named new entrant projects are included in the modelling where there is a high degree of certainty that these will go ahead (i.e., project has reached financial close) including: Flat Rocks wind farm stage 1 (76 MW) for capacity year 2024-25		**Projected new entry and closures** Beyond committed and assumed projects, only commercial generic new entrants are introduced within the modelling. Closure of existing generators where the generator is projected to be unprofitable over

Assumption	Details			
	Collie in late 2027 Muja D in late 2029, Tiwest cogen in 2028 Pinjar in 2031-32 Pinjarra cogen in 2035-36 Cockburn in 2039	Cunderdin Solar farm (100 MW) and battery (55 MW/ 220 MWh) for capacity year 2024-25 Synergy's Kwinana 2 battery (200 MW/ 800 MWh) for capacity year 2024-25 Neoen's Collie battery (200 MW/ 800 MWh) for capacity year 2024-25 Alinta's Wagerup battery (100MW/ 200 MWh) for capacity year 2025-26 Several wind, solar and battery storage projects that are considered probable or close to committed including: Synergy's Collie battery (500 MW/ 2,000 MWh) for capacity year 2025-26 Neoen's Muchea battery (500 MW/ 2,000 MWh) for capacity year 2025-26 Bristol Springs solar farm stage 1 (114 MW) for capacity year 2025-26 King Rocks wind farm (150 MW) for capacity year 2025-26 ocks wind farm stage 2 (100 MW) for capacity year 2026-27		an extended period of time or the generator's expected closure year as indicated by AEMO, whichever is earliest.
New entrant capital costs (renewables and storage)[a]	**Wind** $2,825/kW in 2023 $2,115/kW in 2030 $1,851/kW in 2040 $1,762/kW in 2050	**Solar (single axis tracking)** $1,681kW in 2023 $1,191/kW in 2030 $738/kW in 2040 $551/kW in 2050	**Battery storage (four hours)** $2,335/kW in 2023 $1,116/kW in 2030 $774/kW in 2040 $697/kW in 2050	**CCGT – H2 ready** $1,888/kW in 2023 $1,810/kW in 2030 $1,724/kW in 2040 $1,677/kW in 2050
Gas prices into gas-fired power stations	The WEM modelling assumes consistent gas price commodity assumptions for all gas-fired generation. Only variable charges on the Dampier to Bunbury pipeline are included in generators SRMC. Some variations around this generic gas price series are applied to generator which operate based on legacy contracts such as NewGen which is assumed to operate on its existing gas contract until expiry. In real 2023 terms, assumed gas prices rise from $7/GJ in 2023 to $10/GJ by 2050.			
Coal prices into coal-fired power stations	Coal prices are assumed to rise by around $1.50/GJ (~$30/tonne) in 2023 owing to the supply issues at Premier and Griffin mines, supplemented with imported thermal coal from NSW where required. In real 2023 terms, assumed coal prices into power stations are $4.75/GJ.			

[a] ACIL Allen's modelling considers battery storage technologies of varying duration – the four-hour batteries are the most prevalent duration option in our modelling results.
Note: Unless stated otherwise, all dollar values in this table are presented in real 2023 AUD.
Source: ACIL Allen

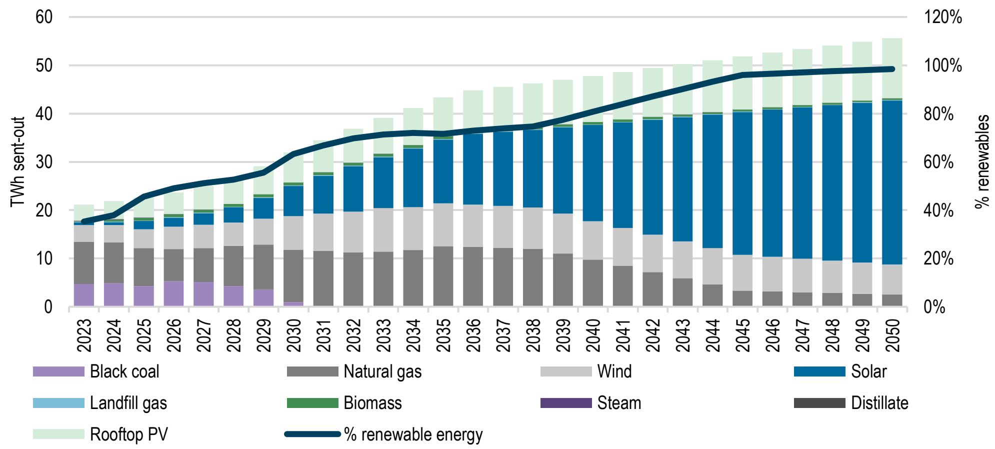
The figure below shows the projected WEM dispatch summarised by fuel type over the period to 2050. Overall consumption volumes grow over time with electrification of industrial processes (primarily alumina), a growing charging load from the uptake of electric vehicles, and some growth in residential and other industrial sectors, which is partially offset by growth in rooftop PV generation.

Coal volumes are projected to remain at historically low levels (less than 5.5 TWh) with supply constraints and higher input prices. Coal generation volumes decline significantly by 2030, with the retirement of the second unit at Muja C in 2024, Collie from 2027-28, Muja D from 2029-30, and Bluewaters from 2030-31, with high efficiency gas-fired generation, battery developments, wind, and solar generation to replace lost capacity and generation volumes.

Renewable penetration is projected to increase from 35% in 2023 to 60% in 2030 and to 99% in 2050.

Natural gas generation volumes (including renewable gas generation after 2040) are projected to increase between 2026 and 2035 as coal closures occur, and then decline over time as older gas-fired generators are retired.

Figure B.1 Projected WEM dispatch: October 2023 Reference case



Source: ACIL Allen PowerMark modelling

Wholesale hydrogen cost modelling C

This appendix outlines the key assumptions we used to model wholesale renewable ('green') hydrogen costs for the Gas Transition Model. We modelled these costs based on two production approaches:

— Firmed production on a 'standalone' basis (that is, using dedicated solar and wind generation that does not interact with the wider electricity grid, as well as dedicated electrolysers, hydrogen storage and pipelines) that delivers a constant 'firmed' flow of hydrogen to a notional user. These costs are likely to be reflective of large-scale hydrogen production such as for major industrial facilities or export-oriented industry. We have modelled these costs based on solar and wind resources available in relatively geographically unconstrained Renewable Energy Zones (REZs), and so we have assumed that the available volume of hydrogen at our modelled price is essentially unlimited.

— An unfirmed series where the flow of hydrogen can vary, reflecting a situation where it is being blended into a larger natural gas supply stream and so can vary in line with the availability of solar and wind. This series was calculated based on the ability of grid-connected electrolysers to flexibly operate at times of low wholesale electricity prices, and this flexibility, combined with the lack of storage costs, means that this series is lower cost than the firmed series. However, we have limited the volume of this unfirmed hydrogen that can be used in the transition model to 3% of overall gaseous fuel demand to reflect technical limits on blending hydrogen into the general natural gas supply.

C.1 Firmed hydrogen modelling methodology

ACIL Allen's approach to modelling standalone firmed hydrogen production costs is to find the optimal mix of solar, wind, and electrolyser capacity to minimise the cost of hydrogen supply. This optimal mix will vary from REZ to REZ, and from year to year, reflecting differences in:

— solar and wind capacity factors, which vary by REZ reflecting the quality of renewable resources specific to that location

— solar and wind generation patterns (captured in AEMO's detailed half-hourly 'traces' for each resource and each REZ, modelled across 29 notional model years that reflect a mix of historically observed weather patterns in that REZ)

— equipment capital costs, with solar and electrolyser costs in particular assumed to decline over time (wind also declines, but not as fast, while we have assumed that large-scale hydrogen storage costs do not decline at all over time)

— storage and firming costs, which generally involves some over-sizing of solar, wind and electrolysers to economise on storage costs

— pipeline costs reflecting the distance of specific REZs from major demand centres.

We modelled both the most challenging year for each REZ (estimated as the model year with the lowest combined solar and wind capacity factor for that REZ) and a typical year for each REZ (estimated as the model year with the median combined solar and wind capacity factor for that REZ). The costs between these two approaches was small – typically $1 to $3 per gigajoule – and so we have adopted results based on a typical weather year.[21] We have calculated the C-2evelized lifecycle cost of projects using an assumed weighted average cost of capital of 7% real).

Some elements of the cost-modelling – for example, pipeline costs – are sensitive to scale. We have assumed a standard project size of 25 petajoules per year for large-scale firmed supply, which would be reflective of a very large industrial user or cluster of medium-to-large-sized users.

As noted above, we have modelled relatively geographically unconstrainted REZs to reflect our assumption that supply volumes are essentially unlimited in the model. Table C.1 summarises the REZs and demand locations modelled, which consists of particularly 'scalable' REZs, with very large land areas available and that are further from existing NEM transmission, where building the solar and wind capacity required for large-scale hydrogen production would be less likely to conflict with spatial and social licence constraints arising from the need to also build solar and wind generation to supply general NEM demand.

Table C.1 Modelled REZs

State	Firmed REZs
Queensland	Q2: North Queensland Clean Energy Hub, piped to Gladstone Q8: Darling Downs, piped to Brisbane
New South Wales	Q2, piped to Newcastle Q8, piped to Newcastle N1: North-west NSW, piped to Newcastle N3: Central-west Orana, piped to Newcastle
Victoria	V2/V3: Murray River (solar) and Western Victoria (wind), piped to Geelong
South Australia	S6: Leigh Creek, piped to Adelaide

Due to a lack of physical space and competition with NEM-connected resources, we have not modelled a Tasmanian REZ. Western Australia and the Northern Territory are not included in the ISP and so AEMO does not publish equivalent solar and wind trace data for WA, and so it has not been possible for us to model Western Australian REZs. For the purpose of modelling, we have assumed that Tasmanian hydrogen prices are the same as Victorian prices, and Western Australian and Northern Territory prices are the same as Queensland prices.

C.1.1 Key assumptions

Solar, wind and electrolyser assumptions

Solar, wind and electrolyser capital costs are the largest cost components of standalone green hydrogen production. For consistency with the electricity sector modelling used in this analysis, we have adopted AEMO's 2022 ISP assumptions for solar and wind and adjusted for inflation to convert them to present day (2023) dollars.

For electrolyser costs, AEMO's published ISP assumptions focus on proton exchange membrane (PEM) electrolysers rather than alkaline electrolysers, despite the latter's lower capital cost. We have used CSIRO's GenCost study (which is itself an input to the ISP) to derive a comparable

[21] Hydrogen consumers may agree to flexible contract terms (e.g. temporary consumption reductions) to avoid the cost of paying for infrastructure to supply hydrogen across all possible weather conditions. Accordingly, we consider the 'typical year' cost to be a fair reflection of likely long-term hydrogen contract prices, though weather and general commercial risk may result in a small premia over these prices.

alkaline electrolyser cost, as the lower capital cost of these electrolysers supports more cost-competitive hydrogen production.

Solar and wind costs are the largest cost component in hydrogen production. They comprise about 60% of firmed hydrogen supply cost in our modelling on average, and about 67% of the cost of unfirmed supply. Electrolysers are the second largest cost component, comprising 20% of firmed supply cost and 26% of unfirmed supply.

Another important assumption is electrolyser efficiency, as this determines the volume of solar and wind generation that must be built to deliver a given volume of hydrogen. AEMO does not publish an alkaline electrolyser efficiency series, but following the IEA,[22] we have assumed that alkaline electrolysers have the same efficiency as AEMO's published PEM efficiency series.

Hydrogen storage costs

Hydrogen storage is important to firm hydrogen supply, and the cost of various forms of hydrogen storage are relatively uncertain. We have followed a US study by researchers from the Argonne National Laboratory to assume standardised per unit costs for three forms of storage:

— salt caverns
— lined rock caverns
— dedicated pipeline storage.

Table C.2 summarises the key assumptions drawn from this study.

Table C.2 Hydrogen storage assumptions

Storage type	Capital cost	Cushion gas requirement
	2021 USD/kg	% of installed capacity
Salt caverns	36.8	31%
Lined rock caverns	59	17%
Dedicated pipeline storage	516	9%

Source: Papadias D and Ahluwalia R, Bulk storage of hydrogen, International Journal of Hydrogen Energy, https://doi.org/10.1016/j.ijhydene.2021.08.028

As salt caverns can only be created in suitable salt deposits, they are limited to certain locations with suitable geology. Within the scope of this modelling, we allow hydrogen producers to access salt cavern storage in either the Adavale basin in south-western Queensland or the Amadeus Basin in southern Northern Territory, but this choice also incurs an additional cost of pipeline transport to the salt cavern location.

On the assumptions used in this work, we find that the more locationally flexible lined rock caverns are generally more economical, as they avoid the need for long dedicated pipelines and also have lower cushion gas requirements. Salt cavern is only selected for one supply option: when supply from the North Queensland Clean Energy Hub (Q2) is delivered to New South Wales, the pipeline corridor passes close by the Adavale Basin and so the incremental pipeline distance required is small. In 2029-30 when the storage requirement is relatively large, the saving from using salt cavern storage instead of lined rock cavern storage is enough to overcome the additional pipeline cost, but this is not the case in later years when cheaper renewable generation and electrolysers reduces the need for storage. On the assumptions sourced above dedicated pipeline storage is more expensive than underground storage and so is not selected in our modelling.

Hydrogen storage comprises about 10% of the cost of firmed hydrogen production in our modelling.

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22 IEA 2023 Electrolysers, https://www.iea.org/energy-system/low-emission-fuels/electrolysers.

Pipeline transport costs

Pipeline transport costs, including the option of 4, 12, or 24 hours of linepack storage, are derived from a recent study undertaken on behalf of APGA.[23] Pipeline costs are incurred to transport hydrogen from the production REZ to the nearest major load centre or pipeline connection point (and to dedicated salt cavern storage locations when that storage option is selected). The spatial assumptions for this modelling are summarised in Table C.3. Pipeline transport comprises about 9% of the cost of firmed hydrogen production in our modelling.

Table C.3 Spatial assumptions for pipeline transport costs

REZ	Assumed production centre	Assumed load centre or connection point	Distance from production to load centres (km)
North Queensland Clean Energy Hub	Hughenden	Gladstone	1100
North Queensland Clean Energy Hub	Hughenden	Newcastle	1950
Darling Downs	Dalby	Brisbane	250
Darling Downs	Dalby	Newcastle	825
North-west NSW	Moree	Newcastle	550
Central West Orana	Wellington	Newcastle	375
North-west Victoria	Warracknabeal	Geelong	325
Leigh Creek	Leigh Creek	Adelaide	575

Note: distances calculated as walking distance with an additional 10% to allow for practical constraints on optimal pipeline route. RBP = Roma-Brisbane Pipeline; EGP = Eastern Gas Pipeline; MSP = Moomba-Sydney Pipeline; VNI = Victoria-NSW Interconnector; MAPS = Moomba-Adelaide Pipeline System.
Source: ACIL Allen analysis using Google Maps

Baseload plant power costs

For the ISP AEMO assumes that small-scale (notionally domestic) electrolysers need constant plant power supply equivalent to 4.5% of the rated electrolyser capacity, and large-scale (notionally export-oriented) electrolysers require 2% of the rated electrolyser capacity. We consider these estimates to translate to very high loads for larger projects and so have adjusted the assumptions such that our unfirmed hydrogen production are assumed to draw a constant load equivalent to 2% of rated electrolyser capacity and our larger firmed production sites draw a constant load of 1% of rated electrolyser capacity.

We have used ACIL Allen *PowerMark* modelling to estimate baseload electricity costs for the spot years modelled (Table C.4). We have not made specific allowance for transmission, retail or green scheme costs – these will be small compared to wholesale power costs for flat consumption of the scale modelled here.

Table C.4 Baseload power price assumptions (2023 $/MWh)

Year	QLD	NSW	VIC	SA
2029-30	$76	$91	$92	$93
2039-40	$119	$112	$119	$112
2049-50	$122	$116	$126	$122

Source: ACIL Allen PowerMark modelling

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[23] GPA 2022, Pipelines vs powerlines: a technoeconomic analysis in the Australian context, https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/pipelines_vs_powerlines_-_a_technoeconomic_analysis_in_the_australian_context.pdf.

Baseload plant power comprises about 3% of the cost of firmed hydrogen production in our modelling.

Water costs

We adopt water cost assumptions from Aurecon's analysis in support of AEMO's ISP.[24] To be conservative we assume that plants will require dedicated desalination, to avoid competition with existing freshwater users. These assumptions indicate a cost of about $3 per kilolitre, which translates to cost of only about 6 cents per kilogram of hydrogen. Water is the smallest cost component we modelled, comprising just over 1% of hydrogen production cost.

C.1.2 Results

Figure C.1 presents ACIL Allen's modelled hydrogen production costs for three spot years: 2029-30, 2039-40 and 2049-50. Costs for years between these points are interpolated based on the implied compound annual growth rate.

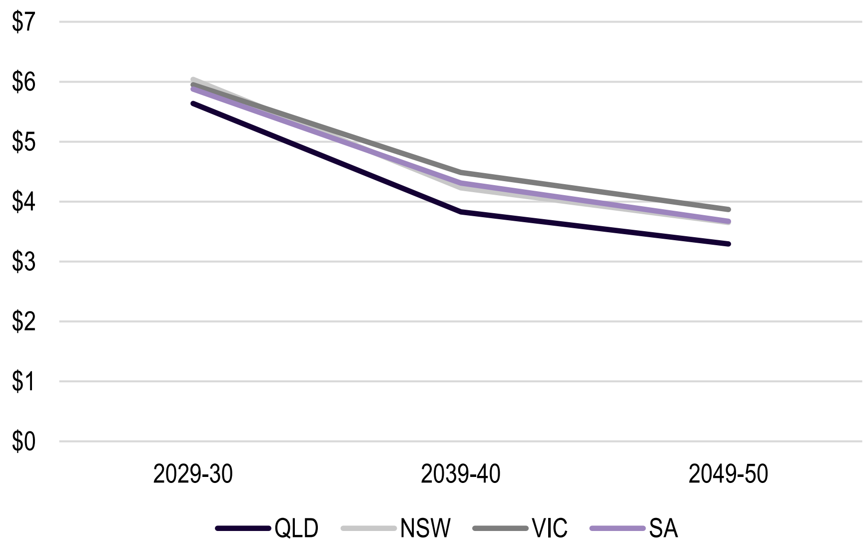
— Queensland has the lowest cost of any region modelled, based on costs in the lowest-cost REZ, the North Queensland Clean Energy Hub.

— New South Wales' most cost-competitive supply option is based on production in the North Queensland Clean Energy Hub and pipeline transport to New South Wales

— Victoria has the highest cost of supply.

— All prices decline consistently over time to reach between $3.3 and $3.9 per kilogram (in real terms) by 2049-50, which is equivalent to about $21 to $28 per gigajoule.

Figure C.1 Firmed hydrogen production cost summary (2023$/kg)



Source: ACIL Allen analysis.

[24] Aurecon 2022, 2021-22 Cost and technical parameter review, https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/2021-cost-and-technical-parameters-review_rev3-21-march-2022.pdf?la=en.

C.2 Unfirmed hydrogen modelling methodology

ACIL Allen has modelling unfirmed hydrogen production as grid-connected, reflecting the generally small size of these projects (which are limited by the volume of demand for unfirmed hydrogen when blended into general natural gas supply).

Estimating the cost of unfirmed grid-connected hydrogen involves:

- analysing detailed (hourly) long-term projections of electricity prices across major electricity markets
- finding the cost-minimising load factor for electrolysers to minimise average production costs (lower load factors will increase per unit electrolyser costs but result in a lower average wholesale electricity purchase price, with the opposite being true for higher load factors.

We have modelled these prices for each NEM region and assumed that WA and NT unfirmed hydrogen prices will be similar to those in Queensland.

C.2.1 Key assumptions

Electricity prices

We have used ACIL Allen's *PowerMark* modelling to analyse hourly wholesale electricity prices across the five NEM regions for four spot years: 2024-25, 2029-30, 2039-40 and 2049-50. We ordered these prices into a series of prices increasing from smallest to greatest, to estimate how average wholesale electricity cost would increase with increasing electrolyser load factor.

Reflecting that these projects are grid-connected we included additional cost components to reflect transmission, retail and green scheme costs. These costs were estimated to be almost $25/MWh in 2024-25, reflecting ongoing costs from the LRET and SRES policies, before declining to $12.7/MWh in 2029-30 and $12/MWh in the long-run.

Electrolyser prices

As for firmed hydrogen production, we have used CSIRO's GenCost study as the basis of our estimate of alkaline electrolyser cost, and AEMO's ISP assumptions as the basis of our assumed electrolyser efficiency series.

Hydrogen and pipeline storage costs

We have assumed that unfirmed hydrogen does not involve any firming of hydrogen supply, and that the point of consumption or grid injection is very close to the point of production. For this reason, we have not assumed any hydrogen storage or pipeline costs for unfirmed hydrogen supply.

Baseload plant power costs

For the ISP AEMO assumes that small-scale (notionally domestic) electrolysers need constant plant power supply equivalent to 4.5% of the rated electrolyser capacity, and large-scale (notionally export-oriented) electrolysers require 2% of the rated electrolyser capacity. We consider these estimates can translate to very high loads, and so we have assumed baseload demand of 2% of rated electrolyser capacity.

As for firmed hydrogen supply, we used ACIL Allen *PowerMark* modelling to estimate baseload electricity costs for the spot years modelled.

Water costs

As for firmed hydrogen supply, we have adopted water cost assumptions from Aurecon's analysis in support of AEMO's ISP,[25] and assumed cost equivalent to that from desalination. Despite this relatively conservative assumption, water costs are a negligible component of overall hydrogen production cost, being about 6 cents per kilogram of hydrogen.

C.2.2 Results

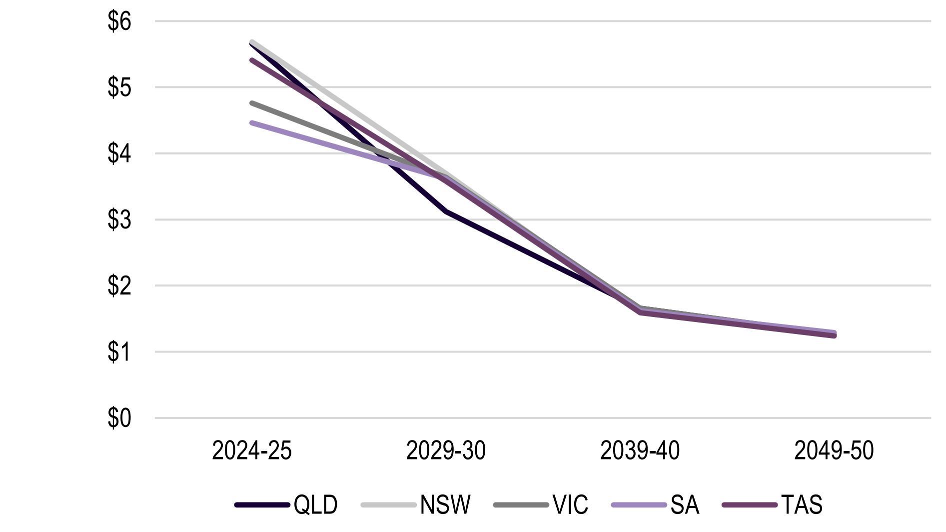
Figure C.2 presents ACIL Allen's modelled unfirmed hydrogen production costs for four spot years: 2024-25, 2029-30, 2039-40 and 2049-50. Costs for years between these points are interpolated based on the implied compound annual growth rate.

— South Australia initially has the lowest unfirmed hydrogen cost, reflecting the high prevalence of negative wholesale electricity prices in that state

— Prices across the NEM converge in the medium to long-term as widespread coal retirements reduce the prevalence of negative prices, and high solar penetration results in a high proportion of zero-priced periods, with the incidence of these periods being similar across all NEM regions

— The long-term price falls to very low levels of about $1.3/kg or about $9/GJ, reflecting the ability of small quantities of electrolysers to purchase zero wholesale electricity at zero cost for about 60% of hours across the year, and the significant decline of electrolyser costs.

Figure C.2 Unfirmed (volume-limited) hydrogen production cost summary (2023$/kg)



Source: ACIL Allen analysis.

[25] Aurecon 2022, 2021-22 Cost and technical parameter review, https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/2021-cost-and-technical-parameters-review_rev3-21-march-2022.pdf?la=en.

Optimal renewable gas target design

D

D.1 Policy context for a renewable gas target

Efficient emissions reduction is best achieved through a broad-based and technologically-neutral policy that provides equally strong incentives across all emissions sources and abatement actions. Theoretically, this is best achieved by internalising the social and environmental costs of carbon emissions through an emissions trading scheme or the imposition of a carbon tax across all sectors of the economy. Either approach would mean that individuals and companies incur a cost that reflects the environmental and social costs of carbon emissions these costs when producing carbon emissions and would have an incentive to reduce emissions when this was cheaper than the carbon price. However, Australia's complicated history with carbon pricing means that implementing such an approach is not likely to be politically feasible for the foreseeable future.

Instead, Australia's policy landscape is characterised by a mix of federal and state policies, providing incentives that vary significantly between sectors, technologies, use cases and locations. Despite the significant variation, this mix of policies is heavily focused on reducing emissions in the electricity sector, by supporting both electricity supply-side abatement and demand-side electrification. For example, the combined effects of the national Renewable Energy Target and a broad range of state-based renewable electricity support policies means that electricity users can confidently expect that emissions from their energy supply will progressively reduce over coming years. Similar policy effort has not been expended to transition natural gas users to renewable gas, and so these gas users do not have the same confidence that their energy supply will decarbonise over time.

A pivotal step to rebalance Australia's emissions reduction policies is to establish a renewable gas target (RGT). Such a target would kick-start supply-side abatement in the gas sector and give todays' gas users confidence that they will have viable low-emissions energy options in the future, similar to what the RET achieved for the electricity sector.

Taking a real options perspective also highlights the value of rebalancing Australia's abatement policy landscape. The fuel and capital cost trajectories of various low-emissions energy options are difficult to predict and what looks to be a dominant or obvious choice today may prove to be more expensive than expected. Instead, policy-makers should support a more extensive range of technology options, in which case emitters will be better placed to choose the best option for them as cost trends become clear and avoid locking in poor choices based on early trends or assumptions.

Box D.1 What is renewable gas

Renewable gases are gaseous fuels that can largely or entirely substitute for existing uses of natural gas in today's energy system. There are three types of renewable gases.

Biomethane

Biomethane is methane produced by anaerobic digestion (decomposition of organic matter by bacteria in an oxygen-free environment). Anaerobic digestion produces biogas a mix of methane, carbon dioxide and various impurities known as biogas. This biogas can be purified or 'upgraded' to biomethane by removing the carbon dioxide and impurities. Any carbon released to the atmosphere by venting unwanted carbon dioxide or burning biomethane still results in zero emissions over the fuel's lifecycle because the carbon was initially captured through the growth of organic material. Accordingly, biomethane can be considered renewable.

As methane is the main component of natural gas, once biogas has been upgraded to biomethane it is entirely substitutable for natural gas and compatible with existing infrastructure and appliances.

Green hydrogen

Green hydrogen is produced by decomposing water into its constituent molecules – hydrogen and oxygen – using renewable electricity. This process is known as electrolysis.

Hydrogen gas is substitutable for natural gas in various uses, including energy and feedstock (natural gas is often converted to hydrogen for use as a chemical feedstock, such as in ammonia production). Therefore green hydrogen can widely substitute for natural gas, though some infrastructure and appliances may require modification or replacement to accommodate the different chemical characteristics of hydrogen.

Renewable synthetic methane

Synthetic methane is produced by combining hydrogen and carbon dioxide in a process known as 'methanation'. When hydrogen and carbon dioxide are produced renewably the product is a renewable gas known as renewable synthetic methane. This methane is entirely substitutable for natural gas.

Green hydrogen production is discussed above. Renewable carbon dioxide production can occur in two main ways:

1. direct air capture, where carbon dioxide is captured from the air and the process is powered by renewable energy
2. organic carbon dioxide, produced by capturing carbon dioxide when upgrading biogas to biomethane or gasifying biomass.

Source: ACIL Allen

An RGT could be pursued through a legislated obligation on gas users to purchase renewable gas, analogous to the approach established through the RET. However, other mechanisms are possible and have been used in various contexts to support clean energy investment. Section D.2 below gives an overview of analogous policies in the Australian context, while Section D.3 considers the pros and cons of various policy options given Australia's stated policy objectives.

Section D.3 also identifies that a renewable gas purchase obligation analogous to the RET is the optimal policy option to implement an RGT. Section D.4 works through detailed policy design considerations for a renewable gas purchase obligation.

D.2 Australian experience with clean energy support policies

Australia has significant experience with policies that support various clean energy technologies, at both the national and the state level. Below we review the high-level features of a range of key policies to provide context for our consideration of policy options for an RGT.

D.2.1 Renewable Energy Target

The national RET was legislated in 2000 with an initial target of supporting 9.5 terawatt-hours (TWh) of new renewable electricity generation by 2010. The initial RET was legislated to cease in 2020. The target was subsequently amended three times.

— In 2009 it was increased to 45 TWh by 2020, which was chosen to target renewable generation equivalent to 20% of forecast national demand[26], with the scheme extended to 2030 to accommodate the target increase.

— In 2011 it was reduced to 41 TWh to reflect the shift of small-scale renewable electricity generation (principally rooftop solar) into a separate scheme.

— In 2015 it was further reduced to 33 TWh, reflecting in part lower electricity demand relative to the forecasts used in setting the 2009 target.

The RET operates by placing a renewable electricity purchase obligation on wholesale electricity customers participating in major grids. These liable customers can acquit their obligations by surrender of certificates created by recognised renewable electricity generators, and so the RET is commonly known as a ‘certificate scheme’. The trading of certificates creates competition between renewable generators and rewards liable entities that better manage their portfolio of renewable generation.

Despite the uncertainty created by various target changes, and fluctuations in certificate prices typical of these schemes, the RET has been effective in supporting investment and delivering its target. For example, investment under the RET slowed during 2014 and 2015 during the review of the target but responded quickly to meet the ultimate 2020 target of 33 TWh and has since continued to increase well above the mandated target level.[27]

Overall the RET has been very effective in achieving its objectives. Not only has the target been comfortably exceeded, but the architecture of the scheme has also provided the basis for widespread action from sub-national governments, corporations and households to purchase additional renewable energy and support abatement additional to the scheme. Familiarity with the RET appears to be a major reason why a broad range of stakeholders support the use of a comparable certificate scheme for an RGT.[28]

D.2.2 NSW Greenhouse Gas Abatement Scheme

The NSW Greenhouse Gas Abatement Scheme (GGAS) commenced on 1 January 2003 and was the first mandatory greenhouse gas emissions trading scheme in the world. Like the RET it took the form of a certificate scheme. NSW electricity retailers and large electricity users were liable under the scheme to purchase certificates representing greenhouse gas abatement achieved through a range of eligible abatement activities. These activities included:

— reduced emissions from existing generators (such as through upgrades that improved efficiency)

— new low-emissions electricity generation

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[26] This 20% national target included pre-existing renewable generators, principally hydro-electric generation. This pre-existing generation supplies about 15 TWh per year on average, and so the revised target implied renewable generation of about 60 TWh out of the then forecast 300 TWh of national demand by 2020.

[27] Clean Energy Regulator 2021, *The 2020 Renewable Energy Target annual statement – large-scale renewable energy target met*, https://www.cleanenergyregulator.gov.au/About/Pages/Accountability%20and%20reporting/Administrative%20Reports/Annual-Statement.aspx.

[28] Future Fuels CRC 2023, *Understanding the implications of a Renewable Gas Target for Australia’s gas networks*, p. 81.

— improved energy efficiency, including a range of activities with deemed efficiency improvements at the household level, such as the distribution of compact fluorescent light globes and low-flow showerheads
— sequestered carbon in forests
— reduced emissions from industrial processes and energy use.

GGAS closed on 1 July 2012 as the emissions reduction objective had been achieved (in part due to investment stimulated through the RET) and also because it was considered duplicative of the national carbon pricing mechanism that took effect at that time. Over 144 million certificates were surrendered over the life of the scheme,[29] nominally representing 144 million tonnes of carbon dioxide equivalent (tCO_2-e) abatement. However, uncertainties about the additionality of many activities credited under GGAS means that the scheme is likely to have achieved less abatement than this in practice.

Administrative costs of the scheme were modest. The scheme regulator, IPART, estimated administrative costs over the life of the scheme of about $18 million, or about 12.5 cents per certificate.[30] This excludes compliance costs of liable entities and abatement providers.

D.2.3 Queensland Gas Scheme

The Queensland Gas Scheme (QGS, sometimes referred to as the Queensland Gas Electricity Certificate Scheme or the GEC Scheme) commenced on 1 January 2005 with a target of ensuring that 13% of Queensland's electricity supply was generated using gas. The target was increased to 15% of electricity supply in 2010.

The scheme was created to support gas supply in Queensland, initially with a view to supporting investment in a proposed pipeline from Papua New Guinea, but later to support Queensland's rapidly emerging coal seam gas sector.

As with the RET and GGAS, the QGS was a certificate scheme that required liable entities (electricity retailers and wholesale customers) to acquit certificates representing eligible gas-fired generation.

The scheme was effective in achieving its objectives. Certificates traded near the scheme's penalty level from 2005 to early 2007, but then declined rapidly as drought conditions curtailed coal-fired generation (and therefore increased gas-fired generation), and as large-scale gas generators were committed to be built. By late 2009 certificates were trading at very low levels.

Around this time there was consideration of increasing the scheme target to 19%, but the operation of the national carbon pricing mechanism from 1 July 2012 and the success of the scheme in supporting gas-fired generation led the Queensland Government to close the scheme from the end of 2013.

D.2.4 Feed-in tariffs

During the late 2000s and early 2010s most states and territories in Australia implemented various feed-in tariff schemes to support small-scale solar generation. A feed-in tariff is a guaranteed minimum payment above general market rates, with a view to supporting investment.

These schemes varied in their design and longevity, but in general succeeded in supporting uptake of small-scale solar. However, they also typically created a boom-and-bust cycle of solar

[29] IPART 2013, *NSW Greenhouse Reduction Scheme: strengths, weaknesses and lessons learned*, https://www.ipart.nsw.gov.au/sites/default/files/documents/nsw_greenhouse_gas_reduction_scheme_-_strengths_weaknesses_and_lessons_learned_-_final_report_-_july_2013.pdf, p. 2.

[30] IPART 2013, *NSW Greenhouse Reduction Scheme: strengths, weaknesses and lessons learned*, p.10.

installations, with the generous feed-in tariffs creating elevated rates of installation, and a slump in investment following the schemes' closure. In this way, these schemes brought forward investment, as well as stimulating it.

The Australian experience demonstrates the simplicity and effectiveness of feed-in tariffs to stimulate investment, but also their inflexibility and their tendency to create a volatile investment environment characterised by boom-and-bust cycles.

D.2.5 Direct contracting

The NSW, Victorian and ACT governments have supported large-scale renewable generation through direct contracting, with these actions complementing incentives under the RET to support investment.

Each state has taken a slightly different approach:

— The NSW Electricity Infrastructure Roadmap sets out a plan for reverse auctions to support up to 12 GW of renewable electricity generation through Long-Term Energy Support Agreements (LTESAs). LTESAs provide a floor price to successful tenderers to reduce their investment risk, rather than a firm offtake price. The NSW Government recently announced results of the first reverse auction, representing about 1,400 MW of renewable generation.

— The Victorian Renewable Energy Target policy established reverse auctions to support renewable electricity generators through long-term contracts that establish a fixed strike price (sometimes referred to 'contracts-for-difference', as payments are made by reference to the difference between the prevailing market price and the contract strike price). The first VRET auction supported 800 MW of wind and solar generation to target 40% renewable generation in the state by 2025, while the second auction supported 600 MW of solar generation to offset emissions from the State Government's own electricity use.

— The ACT's reverse auction policy supported about 600 MW of large-scale renewable generation across the National Electricity Market to notionally supply 100% of the ACT's electricity consumption. As with Victoria, payments to these generators were delivered through long-term contracts-for-difference.

The Victorian and ACT policies are substantially complete and have been effective in achieving their objectives (though projects under the second Victorian auction are yet to be commissioned).

The NSW policy is only at its early stages and so its long-term effectiveness cannot be meaningfully assessed.

D.2.6 NSW Renewable Fuel Scheme

The NSW Government's 2019 Hydrogen Strategy set out a target to develop 8 PJ of hydrogen production within the state by 2030. To achieve this the NSW Government has legislated to create the Renewable Fuel Scheme (RFS), which is a certificate scheme established under the *Electricity Supply Act 1995* in parallel to other similar NSW certificate schemes (the Energy Savings Scheme and the Peak Demand Reduction Scheme, which incentivise energy efficiency and peak demand reductions respectively).

The RFS has not yet commenced and does not have fully detailed rules in place to support the scheme's operation. However, the legislation does establish that gas retailers and large gas users will be the liable entities under the scheme, and that green hydrogen will be an eligible renewable fuel (with the potential for the Minister to establish other eligible renewable fuels through regulations).

D.2.7 WA Hydrogen target

In December 2022 the WA Government announced its intention to develop two hydrogen target certificate schemes:

— An initial scheme focused on electricity generation in WA's South-West Interconnected System, with an indicative target of 1% of generation from green hydrogen

— A subsequent broader scheme to support green hydrogen use across all potential applications, including process heat, feedstock and road transport.

The WA Government is consulting on the design of the hydrogen electricity target scheme. An early consultation paper indicates that the scheme will place liability to purchase certificates representing eligible hydrogen electricity generation on electricity retailers and large customers.[31]

D.3 Policy objectives and assessment of preferred policy option

D.3.1 Policy objectives

Reflecting the context set out in section D.1 the overall purpose of an RGT is to allow renewable gas to compete on a more equal footing with renewable electricity as a viable low-emissions energy option, rebalancing the policy landscape and giving gas users the option to decarbonise without electrification. Therefore, we consider that an RGT should be designed to achieve two primary policy objectives.

— **Reduce emissions.** Renewable gas should be developed as it can make both short-term and long-term contributions to reducing emissions in Australia.

— **Develop the renewable gas industry**. Australia's renewable gas industry is relatively immature, with biomethane development in particular being significantly behind that in Europe and North America. Australia must develop skills and adapt imported technology to local feedstocks and conditions to rapidly take-up renewable gas. This won't be easy to achieve without strong and sustained policy incentives.

An RGT can also contribute to a range of other objectives, though these are secondary to the two discussed above.

— **Improve energy security**. Developing new and diverse energy sources based on local feedstocks and electricity supply can improve energy security. Today's gas supply is based on a handful of large gas sources, which brings a degree of supply risk when major facilities have technical issues. An RGT can develop a new renewable gas supply industry that is likely to be based on many smaller supply points, diversifying supply and reducing critical event risk.

— **Build new demand-side industries**. Australia's rich renewable resources offers the prospect of developing a range of new industries based on the intensive use of zero-emissions energy. Many of these industries depend on renewable gases, including hydrogen and hydrogen-derivative exports, and the reduction of iron ore to green iron using hydrogen. An RGT can develop the skills and supply-side industry to support these new demand-side industries, unlocking significant export-oriented economic opportunities for Australia.

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[31] WA Government 2022, *Renewable hydrogen target for electricity generation in the SWIS*, https://www.wa.gov.au/system/files/2022-10/EPWA-Renewable%20Hydrogen%20Target%20for%20Electricity%20Generation%20in%20the%20SWIS-Consultation%20Paper_0.pdf, p. 14.

D.3.2 Multi-criteria analysis framework for assessing preferred policy option

We have developed a multi-criteria analysis (MCA) framework to analyse the merits of various RGT policy designs. This framework prioritises actions that target our two primary policy objectives: emissions reduction and renewable gas industry development.

Table D.1 Multi-criteria analysis framework

Criterion	Weighting	Evaluation of criterion	Objectives targeted
Effectiveness	30%	Does the scheme offer high confidence that it will achieve the targeted emissions reduction objective?	Emissions reduction
Economic efficiency	30%	Is the scheme designed to achieve the emissions reduction objective in an economically efficient way, and so ensure that the scheme is economically and politically sustainable?	Emissions reduction
Investability	20%	Does the scheme provide investors with sufficient certainty to underpin renewable gas investment?	Renewable gas industry development
Simplicity and administrative feasibility	20%	Is the scheme design simple to establish with low risk of unintended consequences arising in implementation?	Emissions reduction and renewable gas industry development

Source: ACIL Allen analysis

D.3.3 Multi-criteria analysis of potential policy options

ACIL Allen has identified four primary policy options to drive the achievement of an RGT:

— **A certificate scheme.** A government places a renewable gas purchase obligation on gas market participants, with compliance demonstrated through the surrender of certificates created by eligible renewable gas producers (hence a 'certificate scheme').

— **Direct contracting.** A government or government authority contracts with renewable gas producers at prices sufficient to underpin investment and production. Typically contracts would be determined through a competitive reverse auction, so these schemes are sometimes referred to as reverse auction schemes. Costs would be recovered from consumers or governments.

— **Feed-in tariff.** A government sets a mandated minimum payment rate for renewable gas production to support investment and production, with costs recovered from consumers or governments.

— **Direct funding support.** A government provides direct budgetary funding to renewable gas producers to support investment and production.

Below we assess each policy option against the four assessment criteria to determine an overall ranking of the policy options.

Table D.2 Assessment of policy options against criteria

Policy option	Discussion	Rating (out of 5)
Effectiveness		
Certificate scheme	A certificate scheme establishes a purchase obligation that precisely reflects the renewable gas target level. This gives high confidence in achieving the policy target, particularly if the scheme is established in legislation. In general, by directly targeting the policy objective in terms of volume of renewable gas	5

Policy option	Discussion	Rating (out of 5)
	uptake and allowing the price of certificates to vary to achieve this target, certificate schemes are likely to prove highly effective.	
Direct contracting	Governments can undertake multiple auction rounds to calibrate the contracted volume to achieve the renewable gas target level. However, each auction round is subject to budgetary and policy decisions, and contracted projects may be delayed or cancelled. Residual risk remains that this mechanism will fail to achieve the policy target.	4
Feed-in tariff	The feed-in tariff payment level must be set in advance, creating a risk that it will be set at too low a level to achieve the policy target. While the rate could then be adjusted, regular changing of the feed-in tariff would create investor uncertainty and undermine the broader effectiveness of the scheme. In general, it is difficult to use a fixed price feed-in tariff effectively target a specific volume of low-emissions energy uptake.	4
Direct funding	Governments can undertake multiple grant rounds to attract sufficient investment to achieve the renewable gas target. However, each grant round is subject to budgetary and policy decisions. Further, it is difficult to structure grant programs to protect against the risk of project delays and cancellations, creating a material risk that the mechanism will fail to achieve the policy target.	3
Economic efficiency		
Certificate scheme	A purchase obligation is a market-based mechanism that creates competitive tension between renewable gas producers and engages the market knowledge of liable customers to identify suitable projects and credible project proponents. This competitive market-based process supports both allocative efficiency (identifying the markets where renewable gas is most competitive) and productive efficiency (driving cost-efficiency from producers).	5
Direct contracting	Direct contracting typically involves price-based competition between potential providers, but this is limited to the specific requirements determined by each government allocation round. While this supports productive efficiency, it does not necessarily achieve allocative efficiency because governments are not well-placed to identify the commercial value of renewable gas in different markets. For example, natural gas is cheaper in WA than in eastern Australia, in which case an eastern Australian renewable gas project may offer better value than a WA project with lower production cost. In general terms, such a mechanism is not truly market-based as producers can only compete with each other on the terms specified by the government, without necessarily creating an industry that can sustainably compete in the wider energy market.	4
Feed-in tariff	The feed-in tariff payment must be set in advance, creating a risk that it will be set at a level above that needed to meet the target. In that case it will support a range of high-cost (productively inefficient) projects, and undermine dynamic efficiency (by front-loading project development, which precludes later projects that may have benefited from innovation and industry learning).	2
Direct funding	Governments may struggle to assess the true commercial value of projects at arms-length, and so select inferior projects and undermine allocative efficiency. Government grant rounds also suffer from the political need for early commitment, locking the funder into supporting specific projects despite cost over-runs or delays and so undermining productive efficiency.	2
Investability		
Certificate scheme	The financial incentive created by selling traded renewable gas certificates is uncertain and subject to competitive forces. This creates some risk and uncertainty for investors, reducing investability (but increasing efficiency incentives, as discussed above). However, the creation of a mandatory market for renewable gas provides an ongoing investment incentive, creating a	4

Policy option	Discussion	Rating (out of 5)
	significant opportunity for investors to undertake multiple investments that capitalise on the market and technical knowledge developed through early projects.	
Direct contracting	Government contracting provides a high degree of revenue certainty for investors, and a high level of investability. However, the need for budget funding creates uncertainty about the timing and value of future contracting rounds, reducing the scope for multiple investments that build on the knowledge developed through early projects.	4
Feed-in tariff	Government mandating a fixed price gives a high degree of revenue certainty and a high level of investability. However, the risk that the initial feed-in tariff will be set at an overly-generous level creates a risk that it will be reduced over time, reducing the scope for multiple investments that build on the knowledge developed through early projects.	4
Direct funding	Grant recipients enjoy a strong level of government support to invest. However, the need for budget funding creates uncertainty about the timing and value of future contracting rounds, reducing the scope for sequential investments that build on the knowledge developed through early projects.	4
Simplicity/administrative feasibility		
Certificate scheme	A certificate scheme is relatively complex, requiring high quality regulatory oversight and robust compliance and trading systems. However, Australia has experience with such schemes through similar schemes such as the RET, GGAS and QGAS, and existing capabilities and systems that can be readily adapted to support a renewable gas scheme.	3
Direct contracting	Direct contracting is relatively simple, although governments must protect themselves against the risk of delayed or cancelled projects through a range of due diligence checks and assessment gateways, creating some complexity.	4
Feed-in tariff	A feed-in tariff is relatively simple to administer, but it requires a settlement architecture to ensure that projects are paid appropriately and sufficient funds are raised from consumers (or governments) to make these payments.	5
Direct funding	Grant funding is relatively simple, although governments must protect themselves against the risk of delayed or cancelled projects through various due diligence checks and assessment gateways, creating some complexity.	4

Source: ACIL Allen analysis

Based on the assessment in Table D.1 the optimal RGT policy option is a certificate scheme:

1. A certificate scheme achieved a weighted rating of 4.4 out of 5 in our MCA, with high scores (5 out of 5) for effectiveness and economic efficiency.
2. Direct contracting ranked second in our MCA, scoring 4.0 out of 5. It scored good ratings (4 out of 5) on all criteria but is likely to be less effective and efficient than a certificate scheme.
3. A feed-in tariff ranked third in our MCA, scoring 3.6 out of 5. This option is likely to be quite effective and support investment, and is the simplest option to administer, but can lead to economically inefficient outcomes.
4. Direct funding is the weakest policy option, scoring 3.1 out of 5. The reliance on periodic government funding creates uncertainty on the long-term effectiveness of the policy, as well as uncertainty for investors. This approach also is likely to create distorted incentives that undermine economic efficiency.

Key Finding 1 Optimal policy option

A certificate scheme placing a renewable gas purchase obligation on gas market participants is the optimal policy option for achieving a renewable gas target.

D.4 Detailed RGT certificate scheme design

Choosing a certificate scheme as the optimal RGT policy option necessitates a range of detailed policy design considerations. This section sets out the key elements of our proposed optimal RGT certificate scheme (hereafter referred to as a renewable gas scheme or the 'scheme').

D.4.1 Target setting

The long-run target level

A key element of a renewable gas scheme is the long-run or ultimate level of the RGT itself. Without a target that is materially above business-as-usual expectations, the policy will not drive significant abatement or additional investment.

The Australian Government has set a target of achieving net zero emissions by 2050.[32] In this context, one potential ultimate renewable gas target level is 100% of gaseous fuel consumption, which implies zero natural gas consumption. However, two factors indicate that this position may not be appropriate or necessary.

— A net zero target does not imply zero emissions from fossil fuels. It is possible to use offsets from carbon dioxide removal to net out emissions from, say, residual natural gas consumption beyond 2050 and still achieve net zero emissions.

— A renewable gas scheme is unlikely to be the only policy implemented that reduces gas consumption and emissions. For example, the Safeguard Mechanism requires large emitters to reduce emissions, and similar broad-based emissions reduction policies could be implemented to target net zero economy-wide. Given this, an RGT need not be designed to achieve the ultimate objective of net zero emissions, but should be seen as one policy in the broader policy portfolio. An RGT scheme would have a vital early role in driving renewable gas production and consumption in such a portfolio, but in the long-term it would work with other policies to deliver net zero emissions in the gas sector.

In this context, we consider that at least 90% of gaseous fuel consumption should be from renewable gases in the long-run. This allows 'headroom' for some natural gas consumption to continue with matching use of offsets to achieve net zero, while setting a strong and ambitious target for renewable gas production and ensuring that the gas sector does not excessively rely on offsets to reduce emissions.

This target represents a floor or minimum share of renewable gas use, not a ceiling or maximum. Suppose offsetting is a more expensive abatement option than further penetration of renewable gases. In that case, other policy incentives will likely drive renewable gas take-up above the long-run RGT level. This is evidenced by recent outcomes in the electricity sector, where policy and improving economics has seen the level of renewable electricity generation in Australia go well beyond the level mandated by the RET.

[32] *Climate Change Act 2022*, section 10(1)(b).

Key Finding 2 Ultimate renewable gas target level

> The ultimate or long-run renewable gas target level should be 90% of gaseous fuel consumption.

Renewable gas target trajectory

A renewable gas target must ramp up over time to give industry sufficient time to invest in response to the policy. The optimal target trajectory is affected by several factors, and we expect that modelling the scheme will further inform this design element. These factors include:

— short-term constraints such as investment lead times, industry maturity and regulatory barriers
— policy decisions on the exemption of specific gas-using sectors (see section D.4.2, page D-12)
— choices on policy design elements that affect the cost to consumers of failing to achieve targets such as 'borrowing' certificates from the future for compliance and penalty levels (see section D.4.3)
— the need for the ultimate target level to be achieved and held for multiple years before the scheme ends to give later investments sufficient policy support (for example, the RET achieved its ultimate policy target in 2020 but will operate until 2030).

The scheme should start as soon as possible – indicatively 2025, but as soon as practically possible – as the need to develop this abatement option is urgent. However, some flexibility mechanisms may be needed before 2030 to defer early year liabilities as the scheme and the industry matures.

The scheme must operate for a long time to give sufficient time to develop large volumes of renewable gas. It should run until at least 2050 to provide enough time for the required level of investment to occur, and to align with Australia's net zero objective. A long-lived target will also give sufficient certainty to underpin investment in new capital equipment required for renewable gas production, such as anaerobic digesters, biogas upgraders and electrolysers.

We consider that the ultimate target should be reached by 2050, to ensure that the gas sector is contributing significantly to the Australian Government's objective of net zero by 2050. The ultimate target level should be maintained until 2060 to give late investments sufficient incentive to invest.

Key Finding 3 Target trajectory

> The renewable gas scheme should:
> start in 2025, or as soon as practically possible
> involve some flexibility mechanisms for targets between 2025 and 2030 to give industry time to mature and invest to achieve the scheme
> ramp the target strongly from 2030 to achieve the ultimate target by 2050
> hold the target constant at the ultimate target level between 2050 and 2060.

Target specification

An RGT could be specified:

— as a fixed volume of energy (e.g. petajoules of consumption) representing the targeted renewable gas consumption share applied to forecast gaseous fuel demand
— as a fixed share of gaseous fuel consumption, such that the mandated volume of renewable gas consumption varies in line with changes in overall gaseous fuel consumption.

The electricity RET used the first approach, translating the targeted share of renewable electricity generation into a fixed volume of electricity production and consumption, expressed in gigawatt-hours in the legislation. This approach has the advantage of creating a fixed quantity of renewable gas demand for investors to supply but leaves a risk that gaseous fuel demand will grow significantly resulting in the share of renewable gas demand falling below the intended target level. Conversely, the second approach creates a risk falling gaseous fuel demand will reduce the required volume of renewable gas and harm the economics of new renewable gas projects, reducing investor confidence.

Reflecting these two risks we propose a hybrid approach.

— The core RGT should be expressed as a percentage of gaseous fuel demand, allowing it to flex upwards or downwards in line with overall gaseous fuel demand. This flexibility is necessary as there are potential futures where gaseous fuel demand increases significantly – for example through the development of new hydrogen-based industries – or where it decreases significantly – for example through widespread electrification.
— Renewable gas investors should be given some insulation from the risk of falling gaseous fuel demand by setting a fixed volume of renewable gas as a 'floor' target. This will be particularly important early in the scheme's life when the market is immature and financiers are unfamiliar with the renewable gas industry.

The target that applies in any given year would be higher of the core target or the translated floor target, unless the floor target translates to a target higher than 90%, in which case it would be 90% (as discussed above, capping the target at 90% gives the flexibility to use natural gas with offsets alongside renewable gas).

Key Finding 4 Defining the target

> The core renewable gas target should be expressed as a percentage of gaseous fuel demand to accommodate the significant uncertainty in future gaseous fuel demand.
>
> The renewable gas target should incorporate a fixed floor target, expressed as a volume of energy, to insulate early investors in renewable gases from the risk of falling gaseous fuel demand.

D.4.2 Scheme scope, eligibility and liability

Scope and segmentation

In several dimensions, scheme design can be broad and integrated, or more segmented (Table D.1).

Table D.1 Integrated versus segmented renewable gas target approaches

Scheme element	Integrated approach and examples	Segmented approach and examples
Geographic scope	National scheme with a single target	Multiple state-based schemes with separate targets
		National scheme with common state-specific targets
Renewable gas type	Single scheme target for all eligible renewable gases	Sub-targets for specific renewable gases
User type	Scheme target calculated on the basis of all liable users	Defined user sub-categories must achieve specific targets (could be a common target or differentiated)

Source: ACIL Allen analysis

In general more integrated approaches will be more efficient than segmented approaches. Segmenting the scheme target by geography, gas or user type will likely harm efficiency.

— Renewable gases will likely be more competitive with natural gas in some locations than others (for example, due to lower renewable gas production costs or higher prevailing natural gas prices). A single national target allows renewable gas production to be targeted to areas where it is most competitive, reducing cost compared to a segmented approach that requires all jurisdictions to achieve their share of a common national target. Separate state-based scheme will be even less efficient, as their targets and detailed design features will likely vary and so distort investment and increase administrative complexity.
— Requiring all eligible renewable gas types to contribute to meeting a target creates the risk of mandating investment into a portion of relatively expensive renewable gas types. It is more efficient to set a single scheme target for all eligible gases and allow different gas types to compete. This competition promotes both productive and dynamic efficiency.
— Segmenting targets by user types would distort uptake and complicate the scheme. While in the long-run all gas user types must transition to renewable gases (or move away from gaseous fuel), in practice this will be easier for some user types than others. For example, gas-powered generation may find it hard to transition initially, but then transition rapidly as hydrogen-compliant turbines become more widely available. User-segmented targets would impose costs by forcing early adoption of renewable gas in difficult use cases.

Key Finding 5 Scheme scope and segmentation

The renewable gas scheme should be as broadly-based and integrated as possible. That is, it should:
- have a single national target, rather than state-specific sub-targets
- apply equally to all eligible renewable gas types, rather than having gas-specific sub-targets
- apply equally to all gaseous fuel users, rather than having use case specific sub-targets.

Eligible renewable gases

In principle all renewable gases should be eligible to create certificates under the scheme and so contribute to satisfying the RGT. As set out in **Box D.1** the three main renewable gases are biomethane, green hydrogen and renewable synthetic methane.

To keep eligibility as broad as possible, and therefore reduce scheme costs through increased competition between potential renewable gas sources, we consider that biogas (the raw gas produced by anaerobic digestion) should also be eligible to participate in the scheme. However, the scope for use of unpurified biogas is relatively limited. It would need to be blended into pipelines in small quantities to comply with existing pipeline gas specifications, or alternatively could be used ‘behind-the-meter’ (we propose that behind-the-meter renewable gas use be included within the scheme, as discussed below on page D-17).

A key design element is the definition of green hydrogen, specifically, how the emissions profile of electricity production used in hydrogen production is estimated and treated. The Australian Government is developing a ‘guarantee of origin’ (GO) scheme to officially record the production processes and emissions associated with hydrogen production to underpin contracting. A consultation paper released in December 2022 proposed replacing the RET’s accounting framework post-2030 with a similar market-based framework underpinned by ‘Renewable Electricity Guarantee of Origin’ (REGO) certificates.[33] Under this framework, a hydrogen producer

[33] Australian Government 2022, *Renewable electricity certification: policy position paper for renewable electricity certification under the Guarantee of Origin scheme and for economy-wide use*,

would surrender REGO certificates equivalent to its electricity consumption to qualify as green hydrogen, at which time the producer would create a 'product GO' certificate to support the sale of that green hydrogen to a customer. Adopting a parallel accounting framework for our proposed renewable gas scheme would be complex and confusing, so it should be designed to be consistent with the national GO framework once finalised (in other words, surrendering REGO certificates should be sufficient to establish that hydrogen production is renewable, and therefore to create a certificate under the renewable gas scheme).

We have assumed that 'blue hydrogen' (Box D.1) is not included within the scheme because:

— it is not renewable
— it is unlikely to reduce emissions to the same extent as other renewable gases, due to imperfect carbon capture.

Box D.1 What is blue hydrogen?

Blue hydrogen refers to hydrogen produced from fossil fuel feedstock where carbon capture and storage is used to significantly reduce the net emissions created from its production.

The two most common production methods are steam reformation of natural gas and coal gasification.

Source: ACIL Allen

Key Finding 6 Eligible renewable gas types

The scheme should define biomethane, green hydrogen and renewable synthetic methane as eligible renewable gases.

The definition of green hydrogen should be based on the acquittal of official renewable electricity generation certificates, consistent with the Australian Government's proposed hydrogen Guarantee of Origin scheme.

Biogas should also be eligible to participate, provided 'behind-the-meter' gaseous fuel consumption is suitably treated within the scheme design (see Key Finding 9).

We have assumed that blue hydrogen is not included as it is not renewable and would generally not be able to achieve the same emissions reductions as other renewable gases.

Liability

In general, broader scheme liability will better achieve the scheme's primary objectives of emissions reduction and renewable gas industry development, by creating an incentive for more gas end users to take up renewable gas and creating a larger market for renewable gas.

One important exclusion is exported natural gas. The scheme's objective is to reduce emissions within Australia and, consistent with typical international emissions accounting practice, emissions that occur in other countries are out of scope. Consistent with this, natural gas exports should be considered out of scope and so should not incur a liability to purchase renewable gas under the scheme. However, gas used to process natural gas for export is counted in Australia's emissions profile and must ultimately be decarbonised, so this gas use should be liable.

Further, if renewable gas is eligible to create certificates under the scheme, the consumption of this gas should also be treated as liable under the scheme. This reduces the risk that some users will gain a benefit under the scheme by selling certificates without any associated obligation.

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https://storage.googleapis.com/files-au-climate/climate-au/p/prj232e2205fdfa8b85770e8/public_assets/Policy%20position%20paper%20%20-%20%20Renewable%20Electricity%20Certification.pdf.

There are also practical considerations that affect how liability is defined and managed. The three main choices for which entity should be liable are:

— wholesale gas customers, including both retailers who buy gas on behalf of smaller users and large users who directly participate in wholesale gas markets
— gas networks, whose primary role is to transport gas to end users
— wholesale electricity customers, including both retailers and large users.

We do not consider that placing liability on electricity customers is appropriate for two main reasons.

— It would result in the costs of stimulating renewable gas production being placed on many entities that do not benefit from this production, specifically electricity users that do not consume gaseous fuels.
— It would distort the abatement incentives of both electricity and gas users, and so reduce the allocated efficiency of the scheme. In principle, electricity users should pay for the costs of reducing emissions from electricity supply, and gas users should pay those costs for gas supply. When these costs are internalised in the prices of these energy sources, users can make efficient decisions on which fuel offers the best decarbonised energy source for their specific needs. If costs of decarbonising gas are placed on electricity users, these decisions would be biased towards gas use and distorted.

We prefer liability being placed on wholesale gas customers, for three main reasons:

— The electricity RET places liability on wholesale electricity customers, and hence many Australian energy market participants are familiar with this model.
— Wholesale gas customers are active gas market participants, and so are better placed to manage the liabilities associated with the scheme and make commercial decisions on the competitiveness of renewable gas supply options than are networks.
— Not all large gas users are supplied by gas networks with, for example, several large LNG plants undertaking their own production and processing operations (and pipeline transport between them) as a single integrated facility with no recognised gas network involved. Placing liability on gas networks would inadvertently exempt some large users from the scheme and could distort future infrastructure ownership decisions (for example, it would bias against using third-party pipeline infrastructure to connect gas production and liquefaction facilities).

In general, liability for network-connected users can be managed through the same processes that wholesale gas customers manage pipeline withdrawals. Where retailers purchase wholesale gas on behalf of network-connected small users, these retailers would face liability and, presumably, pass scheme compliance costs to small users. Where network-connected large users purchase wholesale gas networks they would be directly liable. To avoid double-counting gas that is traded multiple times in the wholesale market prior to final consumption, the scheme would need to specify that purchases are for the purpose of final consumption. In the RET this concept is known as a wholesale 'acquisition' so we use this term hereafter.

For the small number of non-network-connected gas users, practicality dictates that there should be a size threshold for liability. This threshold could reflect

— the cut-off for liability under the 2012-2014 carbon pricing mechanism of 25,000 tonnes of carbon dioxide equivalent (tCO_2-e), or about 0.5 petajoules of gas consumption
— the Safeguard Mechanism liability cut off of 100,000 tCO_2-e, or almost 2 petajoules of gas consumption.

As most stand-alone gas users are very large – for example, LNG facilities – the practical difference between these two positions is negligible. For consistency with the Safeguard Mechanism, we prefer a 2 petajoule cut-off reflecting about 100,000 tCO_2-e in emissions.

As renewable gas consumption is also liable under the scheme, large standalone renewable gas producing and consuming facilities will be liable. As with large standalone natural gas consuming facilities, such as LNG plants, a size threshold should apply to avoid inadvertently bringing small renewable gas facilities into the scheme and incurring high administrative costs. An example of such a small renewable gas facility would be a small-scale electrolyser suppling hydrogen for vehicle refuelling at a small depot. This threshold should be the same as for natural gas-consuming facilities, with 2 petajoules or more of consumption. Facilities below that size could opt into the scheme to monetise their excess renewable gas production.

Key Finding 7 Scheme liability

All natural gas and renewable gas used within Australia should be liable under the scheme. Exported gas is not used within Australia and should be out of scope.

Wholesale gas customers and users should be the liable entities under the scheme as they are best placed to manage scheme liabilities.

Liable wholesale gas customers would be identified either based on their wholesale acquisitions of gas delivered through a gas network, or by identifying large non-network connected gas users that consume more than 2 petajoules of gas per year.

Exemptions

While liability should be broad in principle, there is a case for reducing the liability of some users to manage the expected scheme costs.

Existing Australian policy practice in the RET, and previously in the carbon pricing mechanism from 2012 to 2014, demonstrates a case for reducing emissions policy costs for emissions-intensive and trade-exposed (EITE) industries. This assistance was established to reduce the risk of disadvantaging Australian industry relative to international competitors, with the associated risk that production and emissions would shift from Australia to other jurisdictions and produce ‘carbon leakage’.

Partial or complete exemption of EITE industries from the scheme is one way of achieving this objective. However, it is not the only approach. As EITE industries represent a large portion of Australia’s gas consumption,[34] exempting these industries from liability would place a disproportionate burden on the remaining non-exempted sectors, particularly gas-fired power generation and residential gas users. As the RGT approaches the volume of non-EITE gaseous fuel consumption, it would become unviable to fully exempt EITE industries as it would require non-exempted entities to purchase more renewable gas than their total consumption.

Instead of exemption, other possible policy approaches include delayed inclusion in the scheme (with early renewable gas targets being lower to reflect the reduction in liable gas consumers within the scheme), or full inclusion in the scheme combined with direct budgetary support to reduce the cost burden of the scheme. Irrespective of the specific RGT design option adopted, most EITE industries would retain strong abatement incentives to reduce emissions under the Safeguard Mechanism.

[34] Initial analysis indicates that gas use by the LNG (own-use only), alumina, ammonia and steel industries alone is about 42% of Australian domestic natural gas consumption. As there are other EITE industries it is likely that EITE gas consumption exceeds 50% of national consumption.

Key Finding 8 Exemptions

> It is unlikely to be viable to exempt emissions-intensive trade-exposed industries in the medium- to long-term under a renewable gas scheme, due to the high proportion of such loads amongst gas users. Other policy options available in finalising a renewable gas scheme include delayed inclusion in the scheme and direct budgetary support to reduce the scheme's impact.

Liability and eligibility carve-outs

As set out in Key Finding 7, wholesale gas customers that acquire gas delivered through gas networks and large non-network gas users with more than 2 petajoules of gas consumption should be liable.

However, a few complex cases require accommodation with the liability rules. Consistent with our general approach of making renewable gas both eligible and liable under the scheme, any adjustments to liability should be mirrored in our approach to eligibility. This reduces the risk that some users will gain a benefit under the scheme by selling certificates without any associated obligation, or conversely that some users will face liabilities under the scheme without an associated benefit.

Two main 'boundary cases' raise questions about how this principle should be applied:

— When a user uses a combination of gas supplied via network (which is liable) and renewable gas supplied 'behind-the-meter' (BTM), should the BTM supply be eligible to create certificates and also included in the calculation of liable gaseous fuel consumption?

— Should a standalone (non-network) facility that relies entirely or largely on renewable gas be liable under the scheme and eligible to create and sell certificates?

Treatment of behind-the-meter supply

BTM supply is produced and used on-site, or produced nearby and supplied by a dedicated (non-network) pipeline. BTM supply is likely to come from renewable gas, such as on-site production and use of biogas or green hydrogen produced from localised electrolysers, so decisions on eligibility and liability are particularly important.

As discussed above on page D-13, broadening eligibility creates competition between more potential renewable gas sources, reducing costs and increasing scheme efficiency. For this reason, we consider that BTM supply should be eligible.

As a corollary, the principle discussed above dictates that the BTM fuel consumption should also be treated as liable consumption. Box D.1 uses a simple worked example to illustrate how this would work.

Box D.1 Worked example of behind-the-meter renewable gas supply

In this worked example we consider a food processing facility that uses 0.5 petajoules of natural gas per year from the local gas network and a further 0.5 petajoules of biogas per year produced behind-the-meter using an on-site anaerobic digester and a renewable gas target of 20%.

In this case both the grid-supplied and behind-the-meter supply are considered liable gaseous fuel consumption, and the facility's share of renewable gas consumption is 50% (0.5 petajoules out of a total of 1 petajoule).

As the renewable gas target is 20%, the food processing facility (or a retailer acting on its behalf in wholesale gas markets) would need to surrender certificates equivalent to 0.2 petajoules of renewable gas consumption (20% of 1 petajoule). Therefore, the food processor or its retailer (depending on contractual arrangements) would have 0.3 petajoules of renewable gas certificates that are excess to its needs, that it could 'bank' for future compliance or sell to other gas users.

Source: ACIL Allen analysis

Practicality and administrative costs may require that BTM production and consumption below a specific size threshold be included in the scheme on an opt-in basis. In any case, renewable gas producers are likely to be very motivated to be included in the scheme so they can register their production as eligible renewable gas and sell any excess certificates to other gas users

Standalone renewable gas consuming facilities

In the future Australia may have a number of standalone renewable gas producing and consuming facilities that do not rely on network gas supply. This could include green ammonia or green steel production using hydrogen supplied from dedicated electrolysers and piped directly to the production facilities.

We consider that these new facilities should be included in the scheme, as this will increase the potential sources of renewable gas and lower the overall cost of complying with the scheme. It will also support the secondary objective of the scheme of supporting new demand-side industries (see section D.3), as these facilities will typically have excess renewable gas certificates that they can sell to other liable entities to generate additional revenue streams.

However, if renewable gas producing and consuming facilities are included in the scheme it is necessary and appropriate to include both their production of renewable gas (which increases supply of certificates) and their consumption of gaseous fuels (which increases demand for certificates). The importance of this is illustrated by considering liability as the RGT approaches its ultimate level of 90%:

— If a renewable gas user can create certificates without any associated liability, it can sell certificates equivalent to its entire gas consumption. But only 10% of its renewable gas consumption exceeds the ultimate RGT of 90%.
— Conversely, suppose the user's gaseous fuel consumption is also treated as liable. In that case, the user will need to surrender 90% of its certificates to comply with the scheme's long-run target, and then, correctly, only has 10% of its certificates available to sell as excess to its requirements.

The difference between these two positions is not material when the RGT is at low levels but becomes significant as the target approaches the ultimate level of 90%.

Bringing large renewable gas-producing and consuming facilities into the scheme will cause the RGT to increase (as it is expressed as a percentage of gaseous fuel consumption), but the availability of renewable gas certificates will increase more proportionally, so it will make the RGT easier to comply with. This means that new renewable gas facilities will tend to 'dilute' the share of market supply from other producers and reduce the price of certificates. These effects are illustrated in the worked example below (Box D.1).

Box D.1 Worked example of new standalone renewable gas producing and consuming facilities

In this worked example we consider:

- the commissioning of a new standalone green ammonia facility that both produces and uses 10 petajoules of hydrogen per year
- a renewable gas target of 50%

In this case the facility can create 10 petajoules of renewable gas certificates and only has a liability to surrender 5 petajoules of certificates. This means that the facility has 5 petajoules of excess certificates to sell to other gaseous fuel users.

Regarding the effect on the national certificate market, we assume that gaseous fuel consumption was 1,500 petajoules and the market was positioned to achieve the annual target without the new green ammonia plant and so has supply of 750 petajoules of renewable gas.

In that case, the annual gaseous fuel consumption has increased to 1,510 petajoules, and the target has increased to 755 petajoules. But renewable gas supply has increased to 760 petajoules, so supply now exceeds demand and the excess 5 petajoules of renewable gas certificates can be banked for compliance in future years.

Source: ACIL Allen analysis

Including large renewable gas producing and using facilities in the scheme interacts with the Safeguard Mechanism in important ways. These interactions are discussed in further detail in section D.4.4 below.

Key Finding 9 Treatment of behind-the-meter and standalone renewable gas consumption

Behind-the-meter and standalone renewable gas production and consumption should be included within the scheme to increase the number of eligible renewable gas sources.

This production should also be treated as liable gaseous fuel consumption with an associated obligation to surrender a share of those certificates.

Practical considerations mean that it is likely to be appropriate to exclude smaller behind-the-meter or standalone renewable gas facilities. However, smaller facilities could opt into the scheme to monetise their renewable gas production in excess of the mandated target.

D.4.3 Other factors that affect efficiency, price and cost

Banking and borrowing

An important design element of a certificate scheme is intertemporal flexibility, or banking and borrowing – that is, the extent to which an entity's liability in a specific year can be met by certificates from an earlier year (banking) or deferred and met with certificates from a future year (borrowing).

Banking is a no-regrets measure and is typically allowed in analogous schemes without restriction. Suppose renewable gas producers can collectively ramp up production to exceed a given year's target. In this case, certificates from this year's excess production should be recognised and rewarded by allowing them to be banked against future liabilities. For example, the RET allows unlimited banking.

Borrowing is more controversial in the design of analogous schemes, illustrated by two potential issues discussed below:

— Borrowing could create a loophole to avoid liability, for example if an individual entity defers its liabilities and then subsequently goes bankrupt.
— A more fundamental issue can arise if numerous entities defer liabilities and then lobby policy-makers to write-off these liabilities or change the scheme design. Such a position would undermine the integrity and credibility of the scheme.

Borrowing should be somewhat restricted to avoid these issues. The RET imposes the following restrictions on how entities manage shortfalls.

— For a shortfall of less than 10% of their total liability, a liable entity can make up a shortfall within three years without penalty (in effect, a three-year borrowing provision).
— For shortfalls of more than 10% of their total liability, a liable entity must pay a cash shortfall charge for the component above 10%. This shortfall charge can be refunded if the entity subsequently achieves compliance.

The banking and borrowing provisions of the RET have supported the overall effectiveness of the scheme and we see no particular reason to adopt different requirements for a renewable gas scheme.

However, one exception is the need to give liable entities sufficient flexibility to comply with the scheme in its early years of operation. Given the need to rapidly ramp-up renewable gas production and the relative immaturity of the renewable gas industry in Australia, it is likely to be appropriate to give liable entities an extended borrowing window in the early years of the scheme, indicatively a five-year window from 2025 to 2029 inclusive. Shortfalls above 10% would be subject to a shortfall charge but entities could make up shortfalls and be refunded within five years, rather than three.

Key Finding 10 Banking and borrowing

The renewable gas scheme should broadly adopt the banking and borrowing provisions of the existing Renewable Energy Target, that is:

unlimited banking (early compliance)

limited borrowing (deferred compliance), with a shortfall charge applying to shortfalls of more than 10% and a period of up to three years in which to make good shortfalls.

The scheme should have an extended five-year borrowing window from 2025 to 2029 inclusive to give liable entities additional flexibility to manage risks when rapidly ramping up renewable gas supply.

Price protection and capping

It is possible that renewable gas supply will not be able to ramp to meet some interim targets, even with the flexibility provided by limited borrowing. Given this risk, the shortfall charge discussed above acts as an unofficial scheme price cap, with liable entities able to pay the shortfall charge in lieu of compliance. Therefore the level of this shortfall charge plays an essential role in managing the risk of acute spikes in the market price of certificates and has important risk management benefit for both gas users and renewable gas producers.

— The shortfall charge caps the overall exposure of gas users to scheme costs, mitigating the potential for extremely high costs.
— Renewable gas producers may enter into contracts that guarantee a particular supply volume, and face commercial penalties for non-delivery. The cost of these penalties can reasonably be the capped at the level of the shortfall charge, reducing the risk of renewable gas investments.

The size of the shortfall charge will need to be informed our modelling of the economics of renewable gas supply. The ultimate level of the shortfall charge should be set in a way that balances the need to provide significant incentive for renewable gas production and the risk to consumers of excessive scheme costs.

Key Finding 11 Capping scheme costs

Under the proposed borrowing provisions, the shortfall charge represents an unofficial price cap for the renewable gas scheme.

An appropriately-determined shortfall charge will balance the need to provide significant incentive for renewable gas production and the risk to consumers of excessive scheme costs.

D.4.4 Other issues and complexities

Interaction with Safeguard Mechanism

The Safeguard Mechanism imposes tightening baselines on the scope 1 (direct) emissions of large facilities emitting more than 100,000 tCO_2-e per year. Currently the scope 1 emissions from natural gas combustion can be calculated in three main ways:

— using generic combustion factors

— through direct sampling of gas composition

— through a combination of sampling and verification of commercial transactions.[35]

If facilities subject to the Safeguard Mechanism ('Safeguard facilities') are able to mix and match between these approaches, there is a risk that incentives under the renewable gas scheme and Safeguard Mechanism will lead to double-counting and 'leakage' of emissions away from Safeguard facilities to non-Safeguard facilities, reducing the efficiency and effectiveness of the scheme:

— Safeguard facilities may be able to claim 100% renewable gas operation based on commercial purchases of renewable gas, while still selling excess certificates under the renewable gas scheme – essentially creating a double benefit through both reduced Safeguard liabilities and revenue from the sale of certificates.

— Non-Safeguard facilities do not have a direct incentive to reduce scope 1 emissions and so will be happy to use generic factors or sampling approaches that assume 0% renewable gas.

— The overall effect will be that overall national emissions reductions in Safeguard facilities will be over-stated by the transfer of credit for renewable gas to those facilities.

While there may be a need for direct sampling to account for variations in gas quality at certain facilities, the best approach is likely to be adopting a nationally-consistent 'gaseous fuels' emissions factor, that reflects the blended emissions intensity of all gaseous fuels that are liable under the renewable gas scheme. This means that all entities contributing to decarbonising gas supply across Australia receive proportional credit through the emissions accounting framework.

This solves two main problems:

— The 'leakage' of emissions from Safeguard facilities to non-Safeguard facilities discussed above.

— Current arrangements could lead to inefficient outcomes. For example, a facility in one state could purchase certificates created from hydrogen injection into a network in another state, and Safeguard facilities connected to that network would get direct benefit from the reduced emissions intensity of their gas use estimated through the sampling approach (due to the

[35] Part 2.3 of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*.

higher hydrogen content).[36] So facilities would be subsidising the decarbonisation of other facilities, distorting incentives under both schemes.

Key Finding 12 Interaction with Safeguard Mechanism

Emissions from gaseous fuel use that is liable under the renewable gas scheme should be estimated for the Safeguard Mechanism using a generic national 'gaseous fuels' emissions factor, with this factor reflecting the national average blend of renewable and non-renewable gases.

This ensures efficient outcomes for all Safeguard Mechanism facilities and reduces the risk that commercial transactions will distort how the use of renewable gas is credited under the Safeguard.

Voluntary uptake of renewable gases

The use of a generic gaseous fuels emissions factor will ensure that increasing use of renewable gas has an even effect across a broad range of gas users (Key Finding 12). To ensure that this approach doesn't dilute incentives for gas users that want to go beyond the minimum mandated level of renewable gas, the renewable gas scheme and emissions accounting approaches should work together to recognise additional voluntary efforts.

For example, a user could surrender renewable gas certificates in excess of their liability as part of a broader corporate strategy to reduce emissions. In this event, emissions accounting under the National Greenhouse and Energy Reporting scheme (and therefore the Safeguard Mechanism) should reflect this voluntary surrender by adjusting that user's direct (scope 1) emissions to reflect their level of renewable gas consumption. In the limit, if a gas user surrendered certificates equivalent to their entire gas usage, their scope 1 emissions from that gas use should be zero.

Key Finding 13 Voluntary uptake of renewable gases

If gas users voluntarily surrender renewable gas certificates above the level mandated under the renewable gas scheme, this should be recognised as a reduction in scope 1 emissions for that user under the National Greenhouse and Energy Reporting scheme and the Safeguard Mechanism.

Baselining pre-existing facilities

The RET baselined pre-existing renewable electricity generators, principally hydro-electric generation, to avoid creating credits from existing generators that would continue to operate even in the absence of the policy.

The logic of baselining pre-existing facilities largely translates to a renewable gas scheme, as crediting pre-existing activities is unlikely to support additional renewable gas production, and therefore may not reduce emissions or develop the renewable gas industry.

However, a renewable gas scheme is being considered in a very different policy environment to that in which the RET was established. There were no material policy incentives for renewable generation prior to the RET, and so it was reasonable to assume that pre-existing electricity generators would continue to operate without any support from the RET. The same is not true of a renewable gas target, with some existing facilities receiving support through other policy mechanisms. The clearest case of this are biogas electricity generators that receive credit for their electricity output under the RET. If the RET closes as planned in 2030 and the renewable gas scheme baselines pre-existing biogas production, it is possible that output from these facilities will reduce due to a lack of sustaining investment.

[36] This does not apply to biomethane as the methane in biomethane is handled the same as methane from natural gas under the physical sampling approach.

There are also practical issues with baselining. For example, biogas production is not always accurately metered, and so it may be difficult to establish a credible baseline.

Given these complexities, the issue of baselines for pre-existing facilities requires further consideration. At a minimum, if pre-existing facilities are not baselined, they should not be allowed to 'double dip' by drawing incentives from both the scheme and other policy measures (see Key Finding 15).

Key Finding 14 Baselining existing facilities

There may be a policy case to baseline pre-existing biogas or other renewable gas producers so that the renewable gas scheme only credits additional production.

However, this policy case is complex and requires further consideration. For example, baselining may not be feasible due to metering difficulties, and may not be appropriate if existing biogas facilities need sustaining investment beyond the life of the RET.

Interaction with other schemes

Today when biogas is burnt to generate electricity the responsible entity is eligible to create certificates under the RET.[37]

This creates a potential for 'double-dipping' if a renewable gas scheme comes into operation before the scheduled closure of the RET in 2030 and existing biogas production used for electricity generation is not baselined (see Key Finding 14). Double-dipping is most problematic for pre-existing facilities, as this does nothing to incentivise additional renewable gas production. This should be prevented through a simple double-dipping provision: if a pre-existing facility has created certificates under the RET it is not eligible to generate credits under the renewable gas scheme, or vice versa.

A somewhat similar risk of double-dipping also arises under state-based hydrogen support schemes such as the NSW Renewable Fuel Scheme (RFS) and the WA hydrogen target. The RFS sets a target of 8 petajoules of renewable hydrogen production by 2030 and holds that target constant from 2030 until the scheme closes in 2044[38] , while the WA scheme has an indicative target that 1% of electricity generation in the South-West Interconnected System should be from green hydrogen.[39]

However, as the investments supported by these schemes will, in most cases, not pre-date the RGT, the question of additionality can be handled differently. The simplest approach is probably to allow renewable gas production to be credited under multiple schemes (e.g. under both the RFS and RGT), but to explicitly adjust the national RGT level upwards to accommodate the established state scheme targets. This will ensure that the RGT will support additional investment beyond what those schemes require.

[37] Section 17 of the *Renewable Energy (Electricity) Act 2000* defines the following potential sources of biogas as eligible renewable energy sources (without any restriction on whether they are burnt directly or processed through a process such as anaerobic digestion): energy crops, agricultural waste, waste from processing of agricultural products, food waste, food processing waste, landfill gas and sewage gas.

[38] *Electricity Supply (General) Regulation 2014 (NSW)*, section 63.

[39] WA Government 2022, *Renewable hydrogen target for electricity generation in the SWIS*, https://www.wa.gov.au/system/files/2022-10/EPWA-Renewable%20Hydrogen%20Target%20for%20Electricity%20Generation%20in%20the%20SWIS-Consultation%20Paper_0.pdf, p. 14.

Key Finding 15 Interaction with other schemes

Pre-existing facilities should not be allowed to create certificates under both the renewable gas scheme and the RET to avoid 'double-dipping'.

New facilities would be allowed to create facilities under multiple schemes, as would likely occur, for example, under the NSW Renewable Fuel Scheme or the WA hydrogen target. However, the national renewable gas target should be adjusted upward to accommodate these schemes and ensure that the national scheme brings forward additional production beyond what is required under state-based schemes.

Interaction with technical regulation

Hydrogen has different chemical characteristics to methane, and so it faces greater pipeline and appliance compatibility issues than biomethane and renewable synthetic methane. A complex hierarchy of rules govern the injection of gases into pipelines and compatibility with appliances, including:

— The National Gas Law and Rules, which apply primarily to the economic regulation of pipelines
— State-based safety regulations applying to the operation of pipelines
— Australian standards applying to specific gas-using appliances.

The need to ensure compatibility with pipelines and appliances, including compliance with relevant regulations and standards, will increase the cost of hydrogen blending relative to biomethane and renewable synthetic methane, disadvantaging hydrogen production. This will be especially true when hydrogen blends are injected into large volume pipeline mains serving larger industrial and commercial gas users, as the compatibility of hydrogen blends with larger gas appliances needs to be assessed on a case-by-case basis.

There is no need for the renewable gas scheme to explicitly manage or anticipate the costs and constraints imposed by safety regulation and appliance compatibility. If hydrogen producers cannot find pipelines willing and able to accept their product, then investors will need to increase supply of biomethane, renewable synthetic methane and behind-the-meter hydrogen or biogas, or facilitate the development of new pipelines to achieve the RGT. Behind-the-meter use of hydrogen is an important way to work around pipeline blending constraints as it can directly target individual users with more hydrogen-compliant appliances, or who are willing to invest to adapt their appliances to take hydrogen.

Key Finding 16 Technical regulation of hydrogen

The renewable gas scheme does not need to make specific allowance for the technical regulation of hydrogen to ensure compatibility with pipelines and appliances. This compatibility is assessed and achieved through other mechanisms.

Summary of sensitivity analysis E

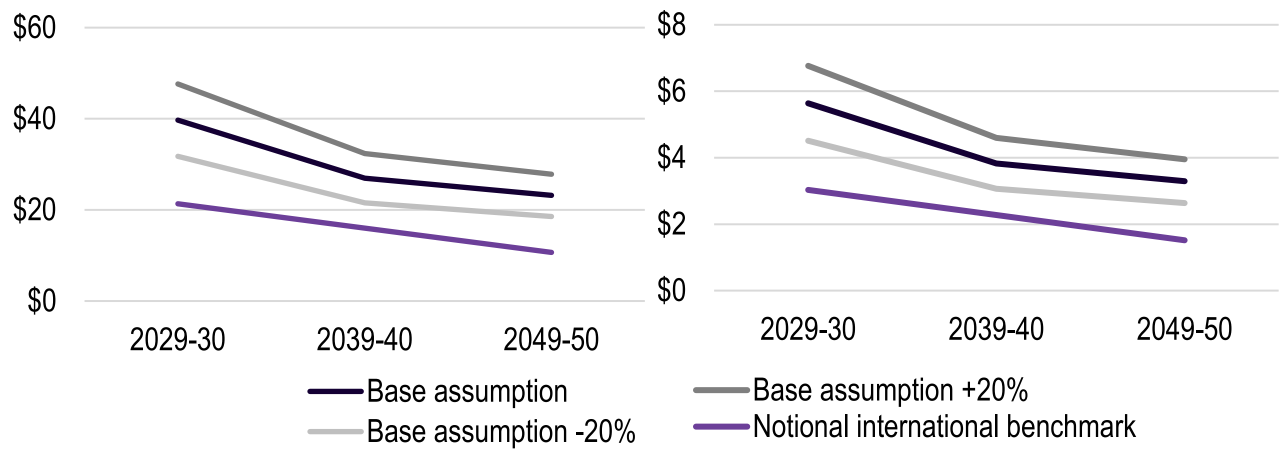
This appendix summarises results for the six sensitivities that vary assumptions from the core assumptions adopted in the modelling scenarios:

— Hydrogen Cost sensitivity
— No Biomethane sensitivity
— High Renewable Gas sensitivity
— High Electrification sensitivity
— High Hydrogen sensitivity
— High Biomethane sensitivity.

For each sensitivity, we present three figures below that show the change in fuel mix for the sensitivity relative to the Theoretical Efficient Policy scenario, the gaseous fuel share for each sector for the sensitivity compared to the Theoretical Efficient Policy scenario, and the detailed fuel and appliance mix at a detailed activity level.

The hydrogen cost assumptions used in the various sensitivities are summarised in Figure E.1. This illustrates that we have tested a range of potential hydrogen costs, but our lower hydrogen cost assumptions remain above the widely-discussed international green hydrogen cost benchmarks of USD2/kg in 2030 and USD1/kg in 2050.

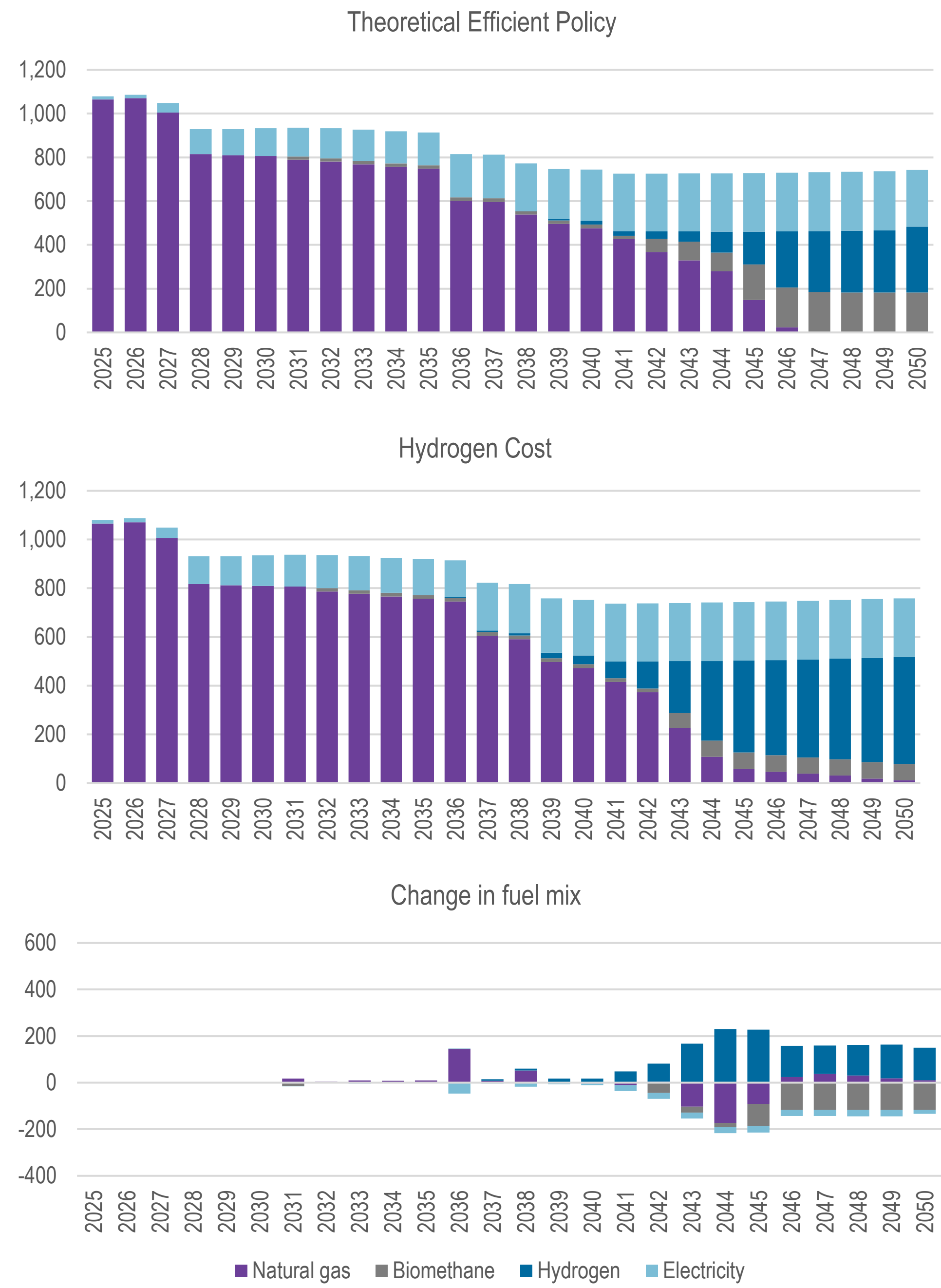
Figure E.1 Queensland firmed hydrogen production cost, by scenario and sensitivity: ($/GJ, LHS; $/kg, RHS)



Note: the notional international benchmark is based on hydrogen cost of USD2/kg in 2030 and USD1/kg in 2050, converted to AUD at an exchange rate of 0.66 USD:AUD.

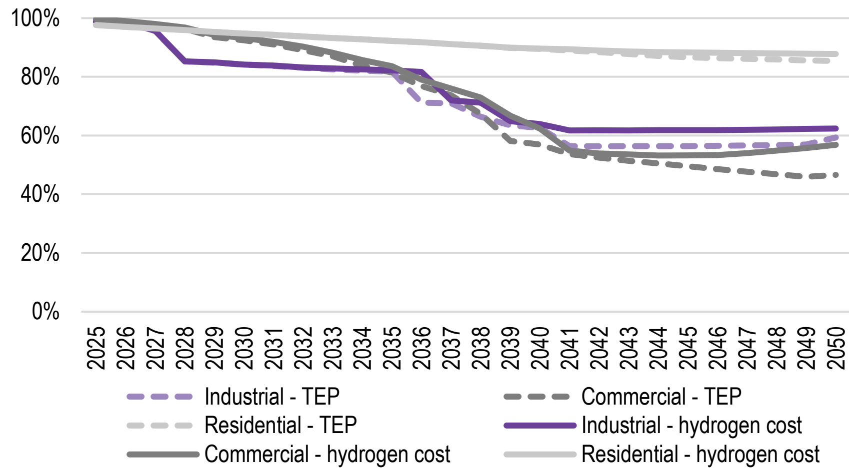
Source: ACIL Allen analysis

Figure E.2 Fuel mix (PJ): Theoretical Efficient Policy scenario, Hydrogen Cost sensitivity, and change between Theoretical Efficient Policy scenario and Hydrogen Cost sensitivity



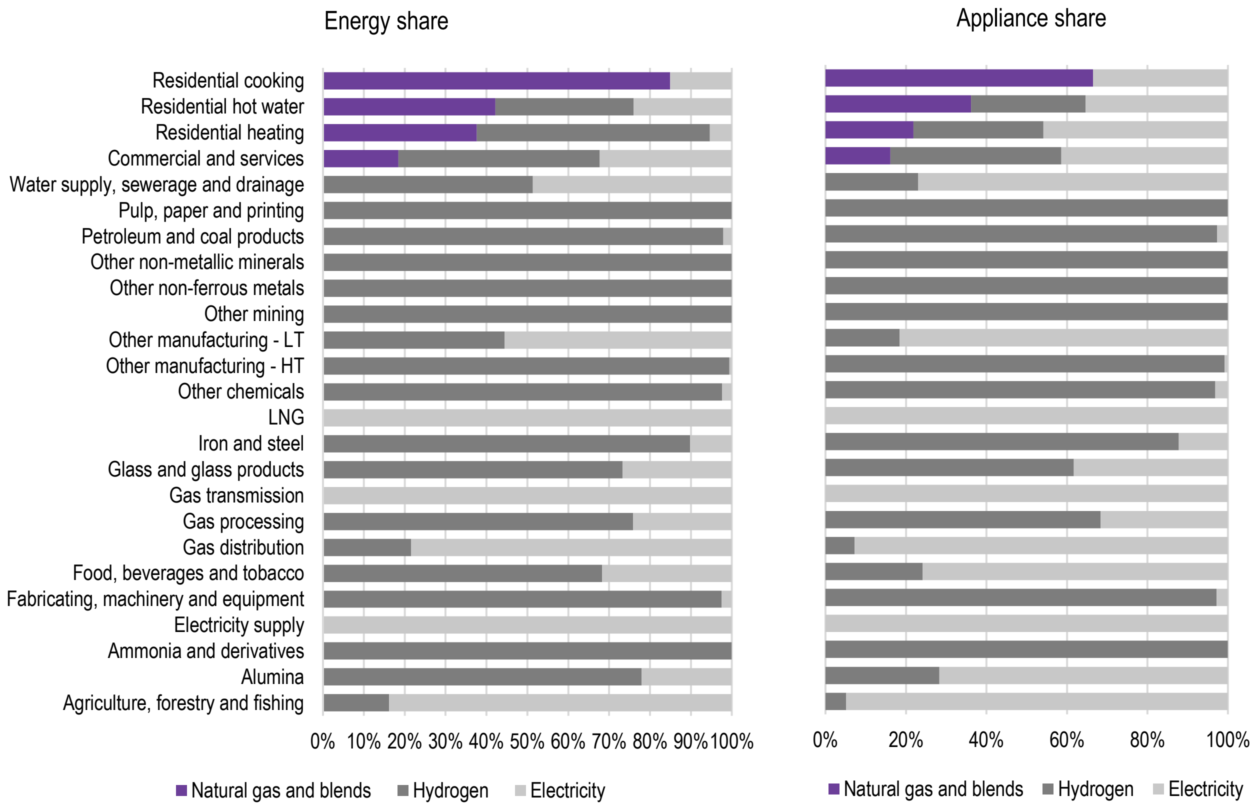
Source: Gas Transition Model

Figure E.3 Gaseous fuel share (%), by sector: Hydrogen Cost sensitivity compared to Theoretical Efficient Policy scenario



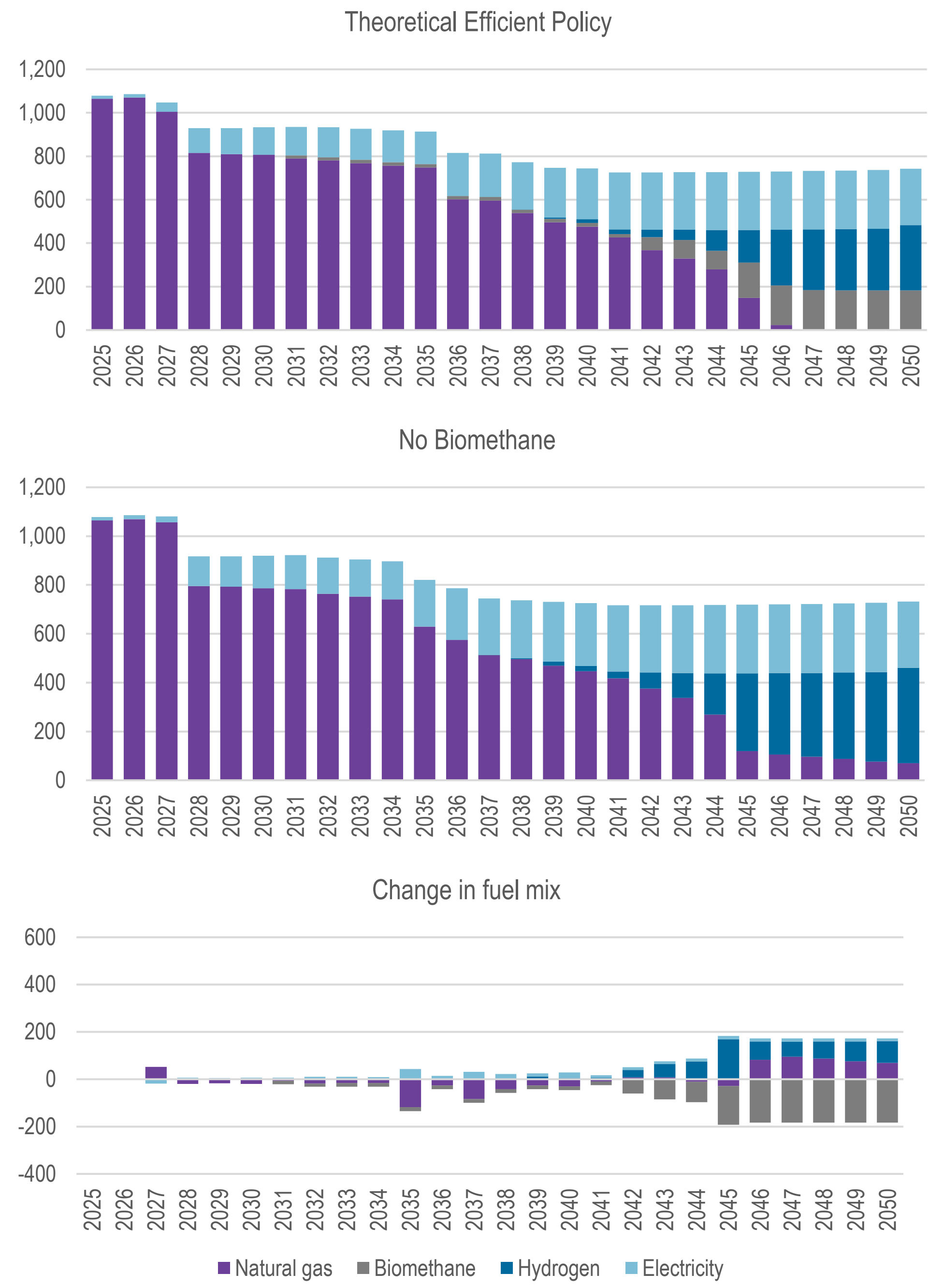
Source: Gas Transition Model

Figure E.4 Energy and appliance shares by sector and fuel type in 2050: Hydrogen Cost sensitivity



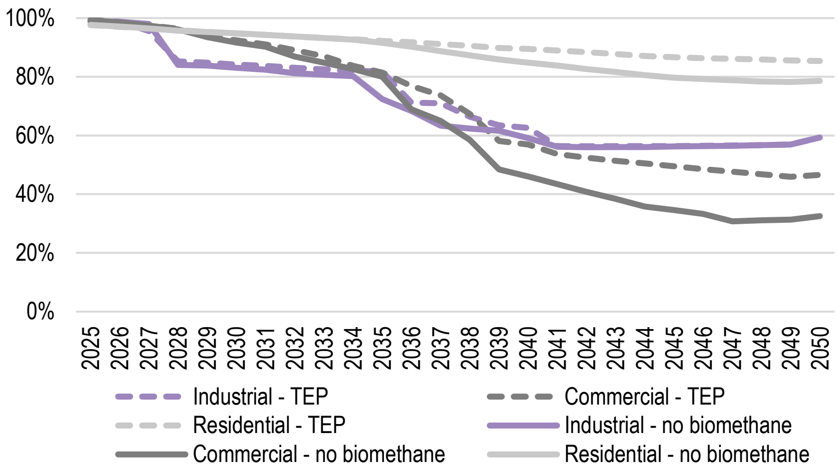
Source: Gas Transition Model

Figure E.5 Fuel mix (PJ): Theoretical Efficient Policy scenario, No Biomethane sensitivity, and change between Theoretical Efficient Policy scenario and No Biomethane sensitivity



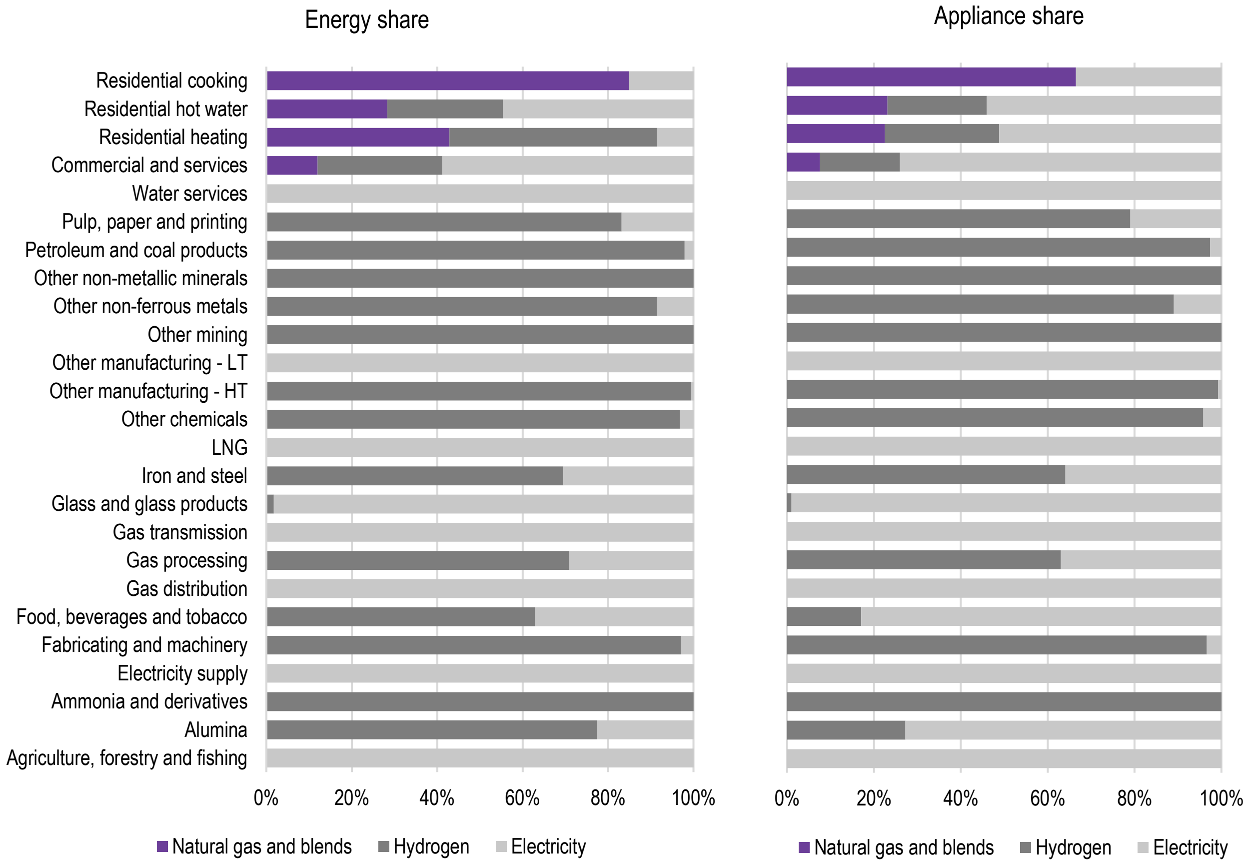
Source: Gas Transition Model

Figure E.6 Gaseous fuel share (%), by sector: No Biomethane sensitivity compared to Theoretical Efficient Policy scenario



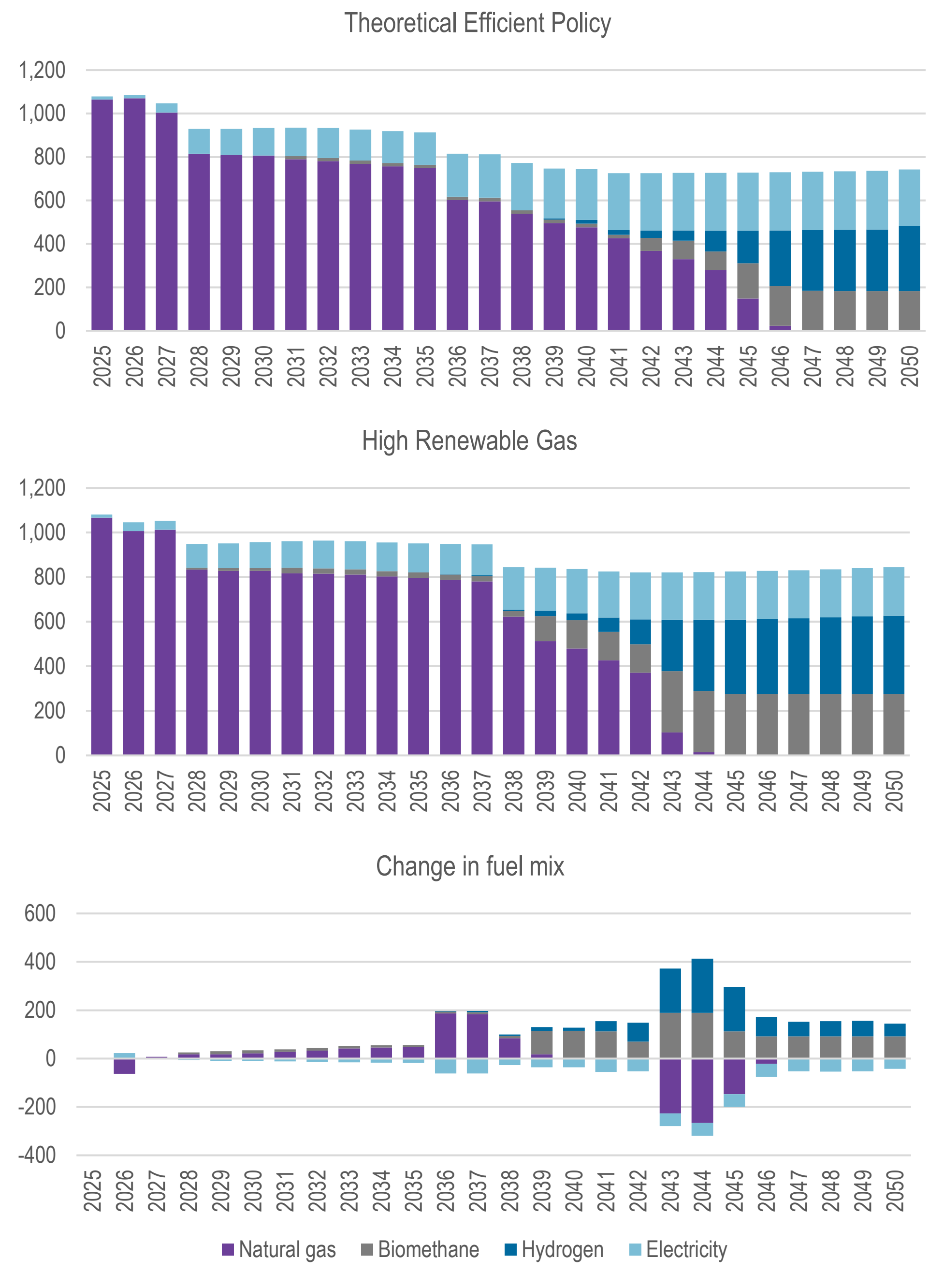
Source: Gas Transition Model

Figure E.7 Energy and appliance shares by sector and fuel type in 2050: No Biomethane sensitivity



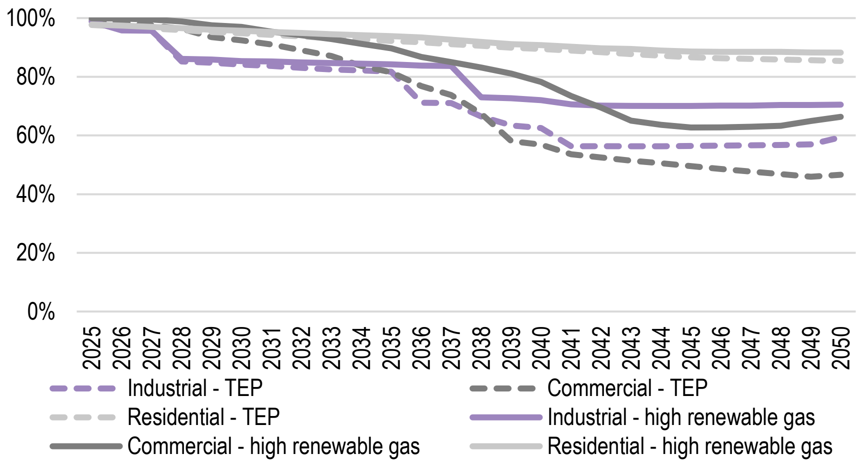
Source: Gas Transition Model

Figure E.8 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Renewable Gas sensitivity, and change between Theoretical Efficient Policy scenario and High Renewable Gas sensitivity



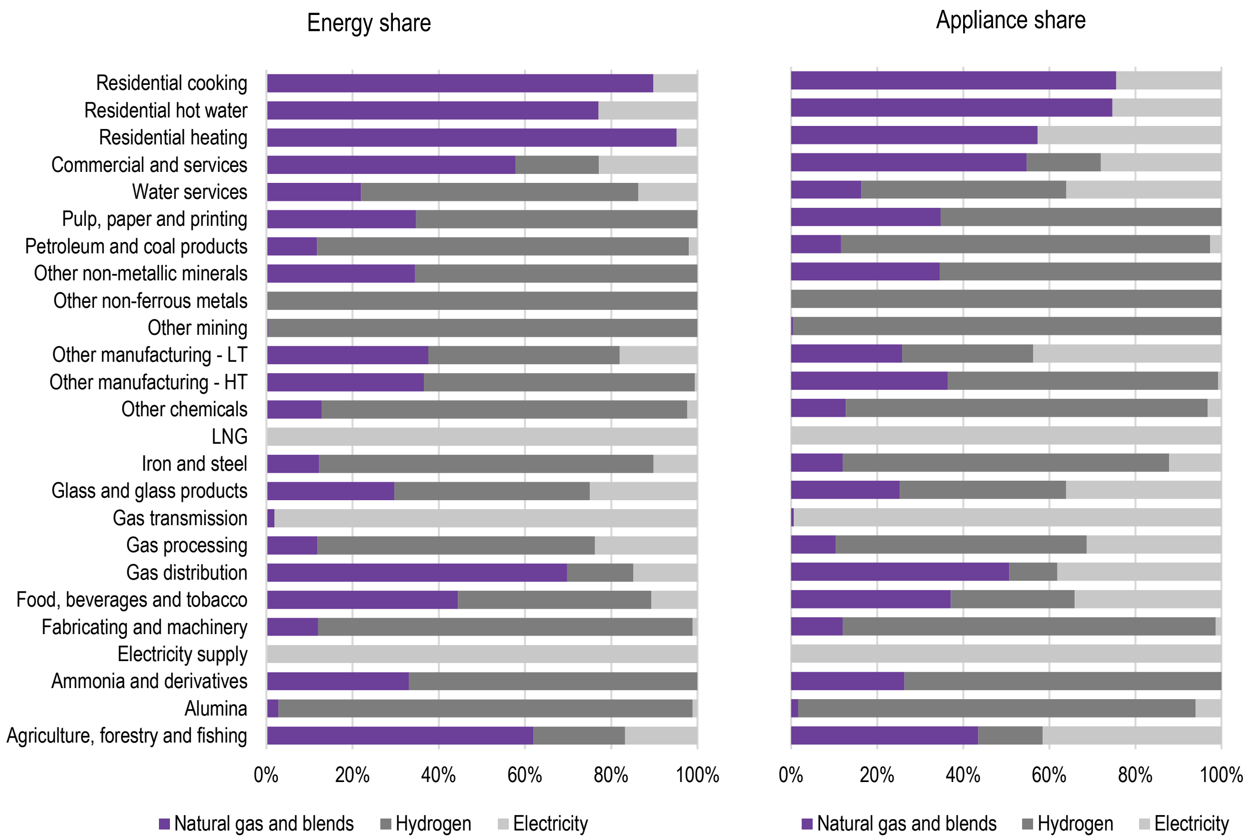
Source: Gas Transition Model

Figure E.9 Gaseous fuel share (%), by sector: High Renewable Gas sensitivity compared to Theoretical Efficient Policy scenario



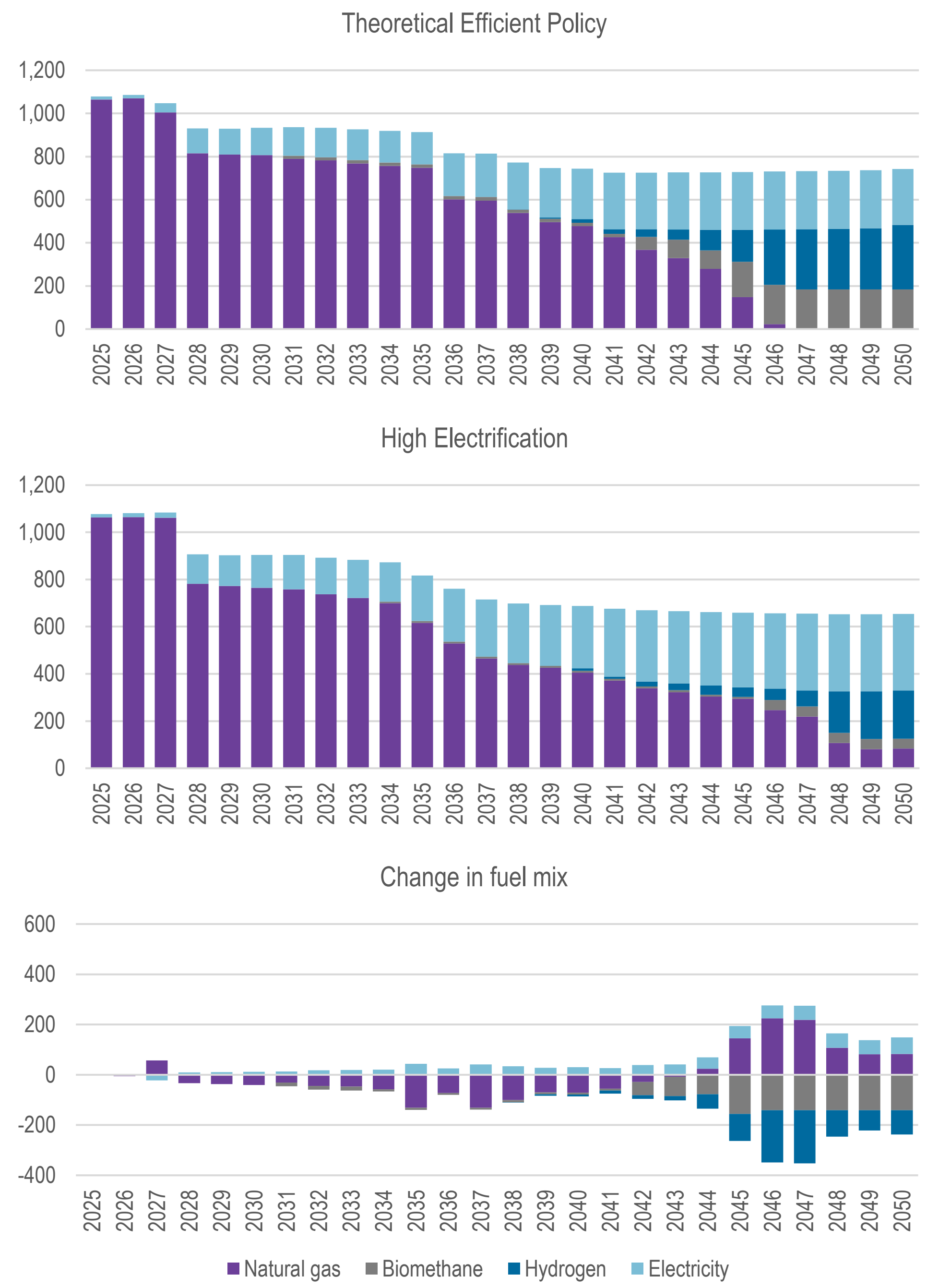
Source: Gas Transition Model

Figure E.10 Energy and appliance shares by sector and fuel type in 2050: High Renewable Gas sensitivity



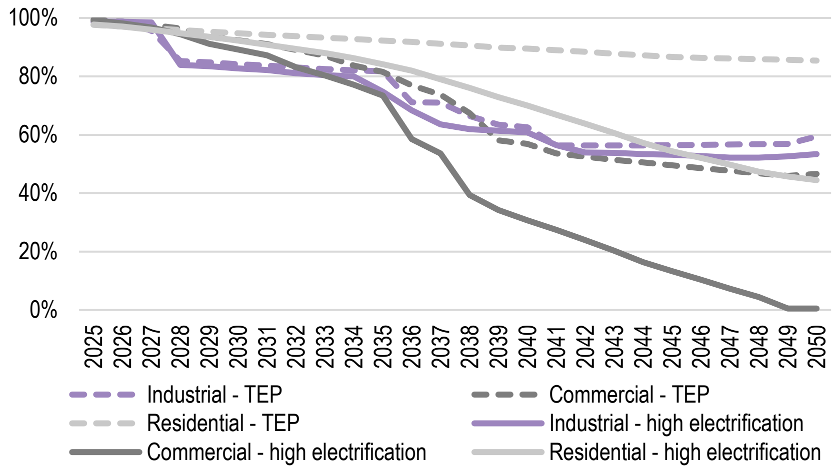
Source: Gas Transition Model

Figure E.11 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Electrification sensitivity, and change between Theoretical Efficient Policy scenario and High Electrification sensitivity



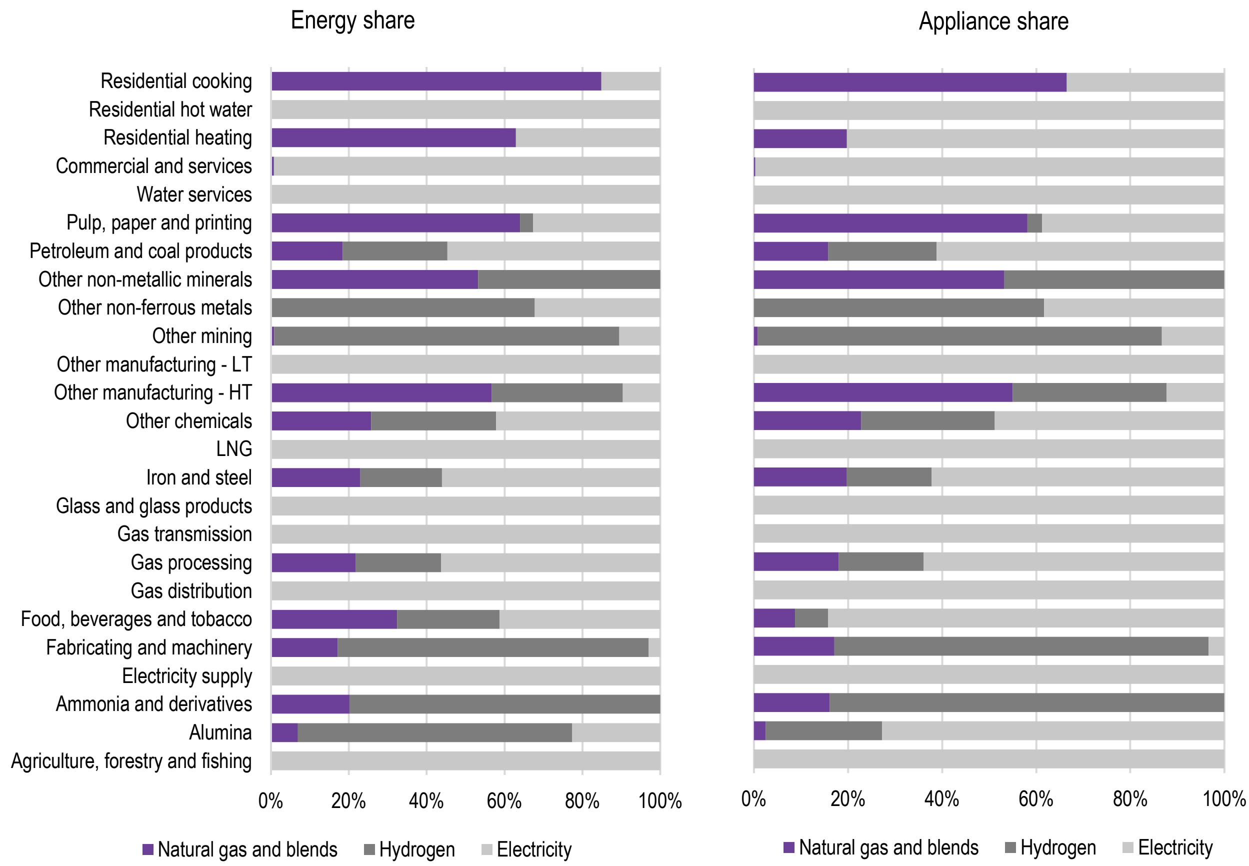
Source: Gas Transition Model

Figure E.12 Gaseous fuel share (%), by sector: High Electrification sensitivity compared to Theoretical Efficient Policy scenario



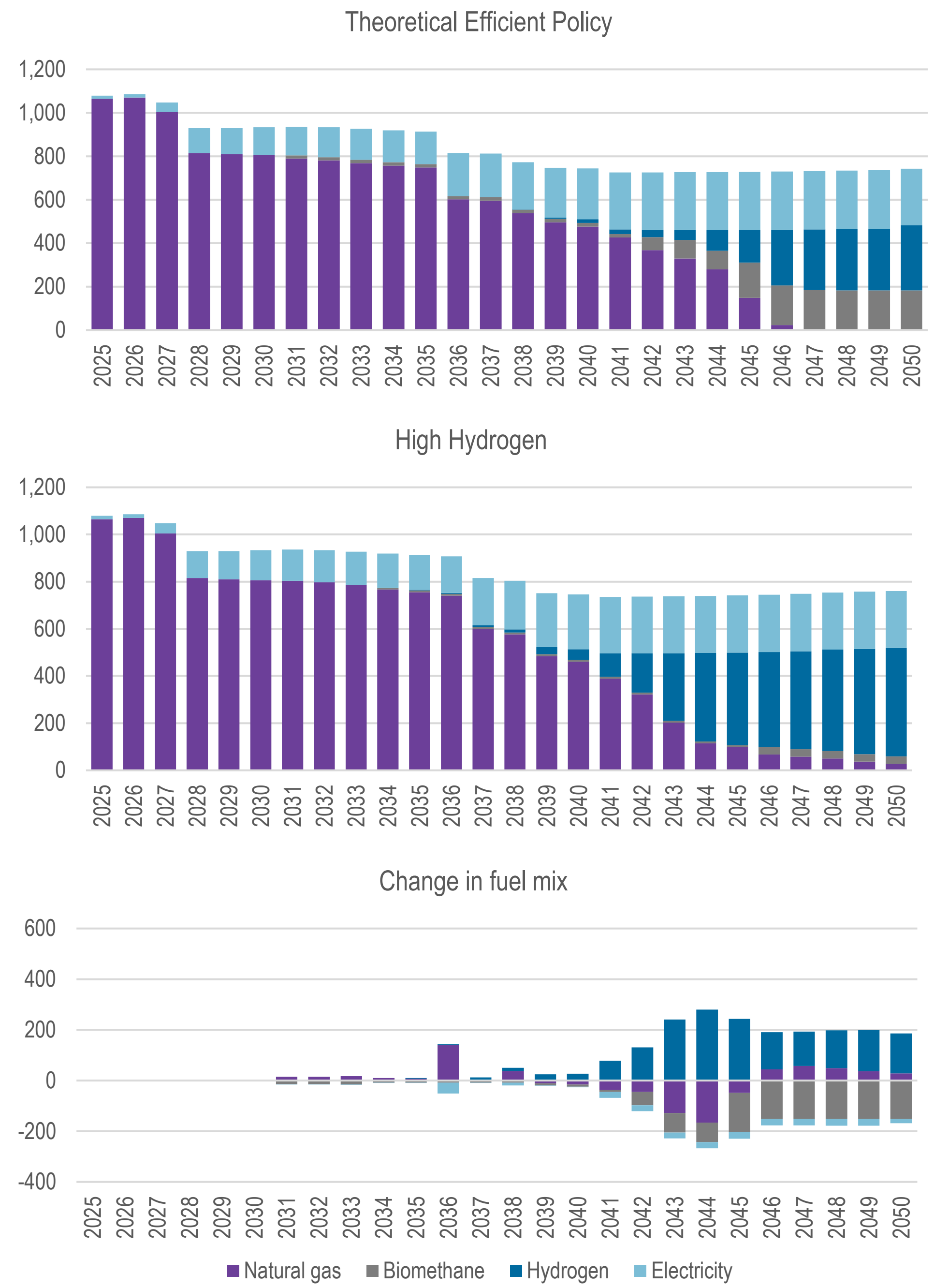
Source: Gas Transition Model

Figure E.13 Energy and appliance shares by sector and fuel type in 2050: High Electrification sensitivity



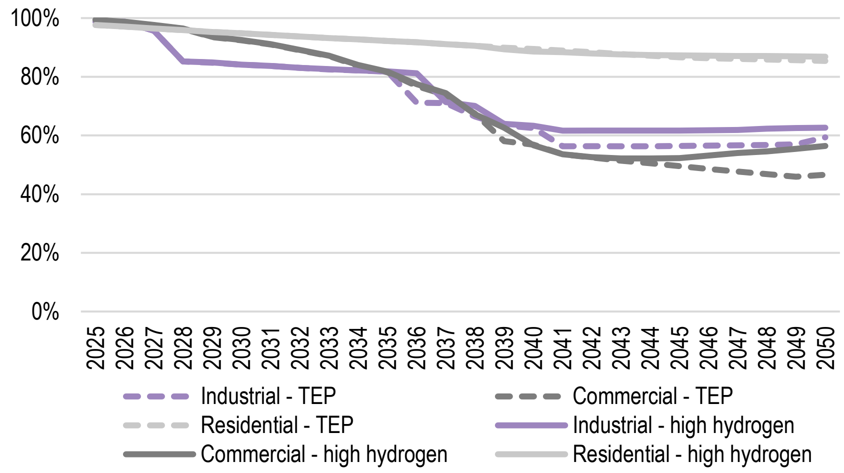
Source: Gas Transition Model

Figure E.14 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Hydrogen sensitivity, and change between Theoretical Efficient Policy scenario and High Hydrogen sensitivity



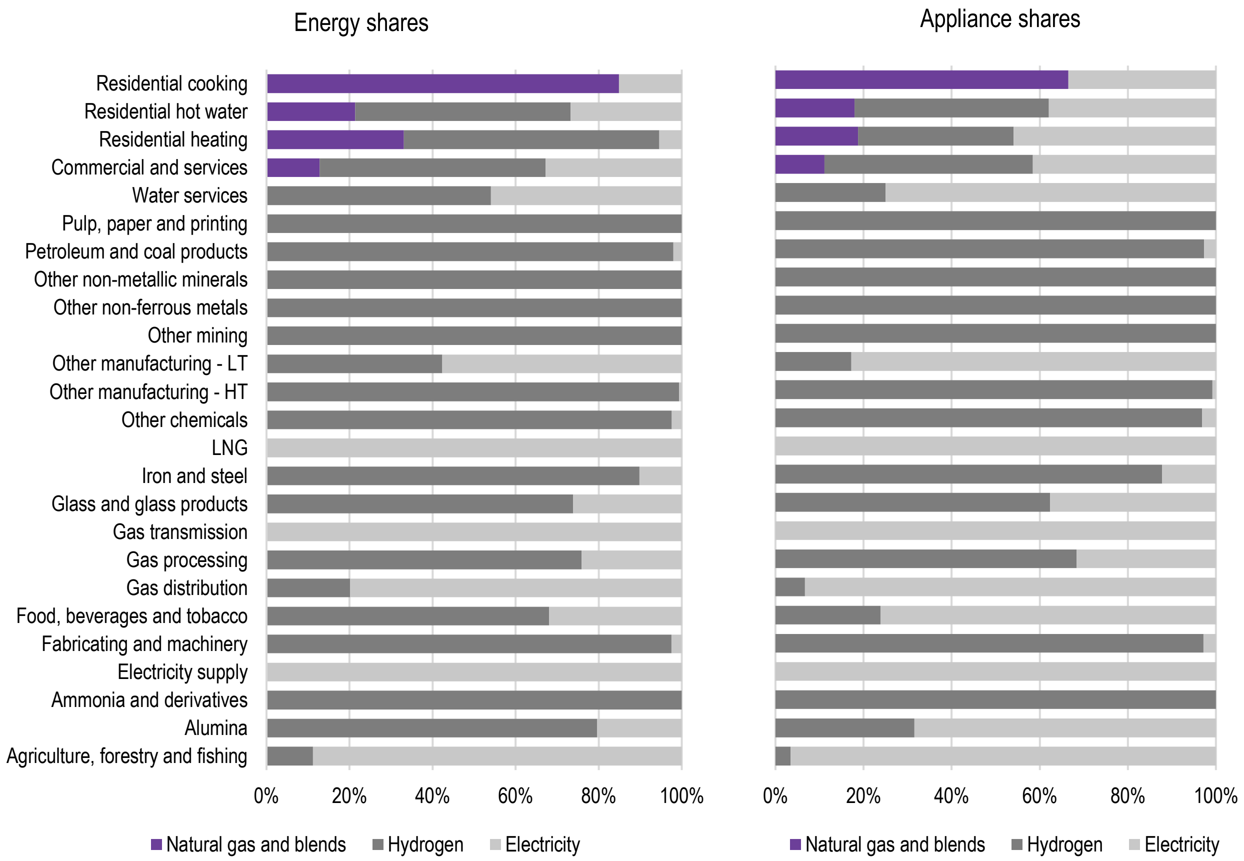
Source: Gas Transition Model

Figure E.15 Gaseous fuel share (%), by sector: High Hydrogen sensitivity compared to Theoretical Efficient Policy scenario



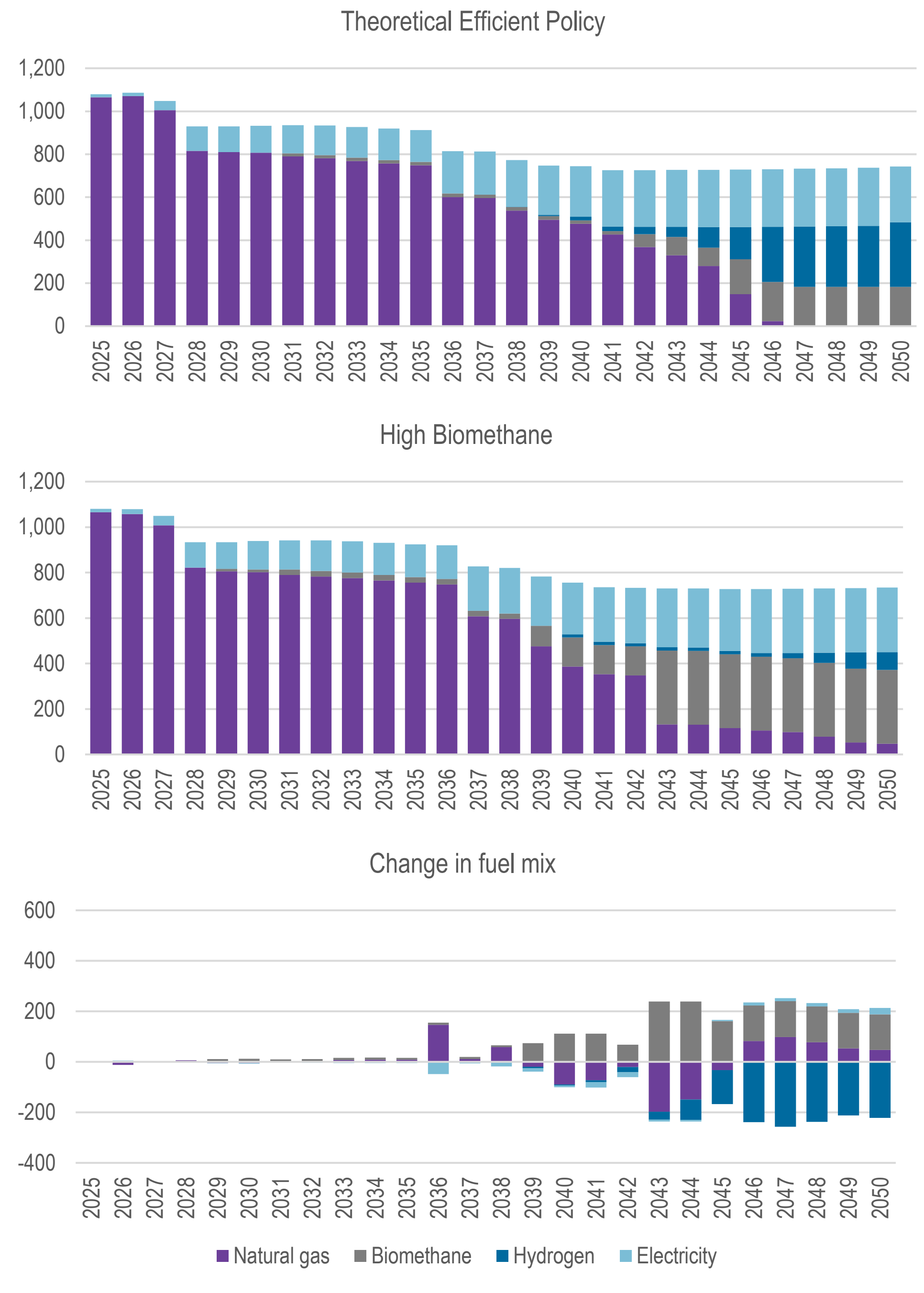
Source: Gas Transition Model

Figure E.16 Energy and appliance shares by sector and fuel type in 2050: High Hydrogen sensitivity



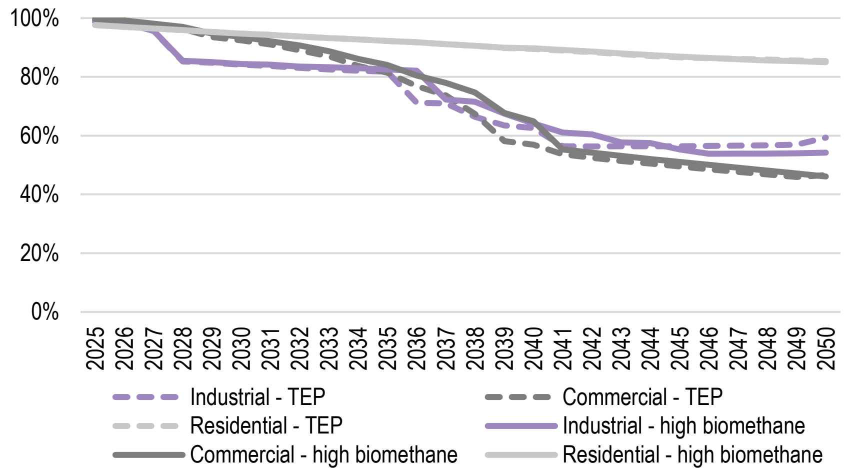
Source: Gas Transition Model

Figure E.17 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Biomethane sensitivity, and change between Theoretical Efficient Policy scenario and High Biomethane sensitivity



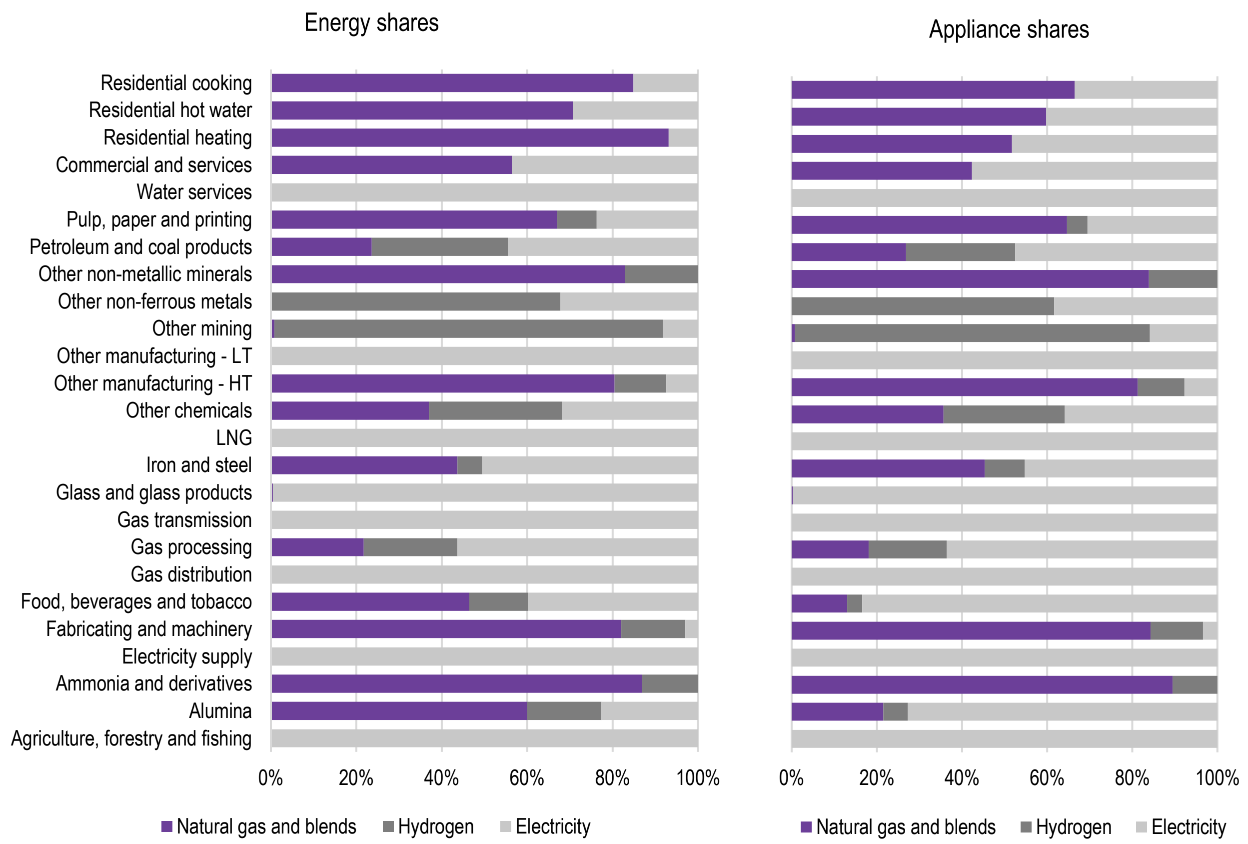
Source: Gas Transition Model

Figure E.18 Gaseous fuel share (%), by sector: High Biomethane sensitivity compared to Theoretical Efficient Policy scenario



Source: Gas Transition Model

Figure E.19 Energy and appliance shares by sector and fuel type in 2050: High Biomethane sensitivity



Source: Gas Transition Model

Overview of Tasman Global

F

Tasman Global is a dynamic, global CGE model that has been developed by ACIL Allen for the purpose of undertaking economic impact analysis at the regional, state, national and global level.

A CGE model captures the interlinkages between the markets of all commodities and factors, taking into account resource constraints, to find a simultaneous equilibrium in all markets. A global CGE model extends this interdependence of the markets across world regions and finds simultaneous equilibrium globally. A dynamic model adds onto this the interconnection of equilibrium economies across time periods. For example, investments made today are going to determine the capital stocks of tomorrow and hence future equilibrium outcomes depend on today's equilibrium outcome, and so on.

A dynamic global CGE model, such as *Tasman Global*, has the capability of addressing total, sectoral, spatial and temporal efficiency of resource allocation as it connects markets globally and over time. Being a recursively dynamic model, however, its ability to address temporal issues is limited. In particular, *Tasman Global* cannot typically address issues requiring partial or perfect foresight. However, as documented in Jakeman et al (2001), it is possible to introduce partial or perfect foresight in certain markets using algorithmic approaches.[40] Notwithstanding this, the model does have the capability to project the economic impacts over time of given changes in policies, tastes and technologies in any region of the world economy on all sectors and agents of all regions of the world economy.

Tasman Global was developed from the 2001 version of the Global Trade and Environment Model (GTEM) developed by ABARE (Pant 2007)[41] and has been evolving ever since. In turn, GTEM was developed out of the MEGABARE model,[42] which contained significant advancements over the Global Trade Analysis Project (GTAP) model of that time.[43]

F.1 A dynamic model

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before an economic disturbance and one following). A dynamic model such as *Tasman Global* is beneficial

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[40] Jakeman, G., Heyhoe, E., Pant, H., Woffenden, K. and Fisher, B.S. (2001). *The Kyoto Protocol: economic impacts under the terms of the Bonn agreement*. ABARE paper presented to the International Petroleum Industry Environmental Conservation Association conference, 'Long Term Carbon and Energy Management - Issues and Approaches', Cambridge, Massachusetts, 15-16 October.

[41] Pant, H.M. (2007), *GTEM: Global Trade and Environment Model*, ABARE Technical Report, Canberra, June.

[42] Hanslow, K. & Hinchy, M. (1996). *The MEGABARE model: interim documentation*. Canberra: ABARE.

[43] Hertel, T. (1997). *Global Trade Analysis: modelling and applications.* Cambridge University Press, Cambridge.

when analysing issues for which both the timing of and the adjustment path that economies follow are relevant in the analysis.

F.2 The database

A key advantage of *Tasman Global* is the level of detail in the database underpinning the model. The database is derived from the GTAP database.[44] This database is a fully documented, publicly available global data base which contains complete bilateral trade information, transport and protection linkages among regions for all GTAP commodities. It is the most detailed database of its type in the world.

Tasman Global builds on the GTAP database by adding the following important features:

— a detailed population and labour market database

— detailed technology representation within key industries (such as electricity generation and iron and steel production)

— disaggregation of a range of major commodities including iron ore, bauxite, alumina, primary aluminium, brown coal, black coal and LNG

— the ability to repatriate labour and capital income

— explicit representation of the states and territories of Australia

— the capacity to represent multiple regions within states and territories of Australia explicitly.

Nominally, version 10.1 of the *Tasman Global* database divides the world economy into 153 regions (145 international regions plus the 8 states and territories of Australia) although in reality the regions are frequently disaggregated further. ACIL Allen regularly models Australian or international projects or policies at the regional level including at the or at the state/territory/provincial level for various countries.

The *Tasman Global* database also contains a wealth of sectoral detail currently identifying up to 76 industries (Table F.1). The foundation of this information is the input-output tables that underpin the database. The input-output tables account for the distribution of industry production to satisfy industry and final demands.

Industry demands, so-called intermediate usage, are the demands from each industry for inputs. For example, electricity is an input into the production of communications. In other words, the communications industry uses electricity as an intermediate input.

Final demands are those made by households, governments, investors and foreigners (export demand). These final demands, as the name suggests, represent the demand for finished goods and services. To continue the example, electricity is used by households – their consumption of electricity is a final demand.

Each sector in the economy is typically assumed to produce one commodity, although in *Tasman Global*, the electricity, transport and iron and steel sectors are modelled using a 'technology bundle' approach. With this approach, different known production methods are used to generate a homogeneous output for the 'technology bundle' industry. For example, electricity can be generated using brown coal, black coal, petroleum, base load gas, peak load gas, nuclear, hydro, geothermal, biomass, wind, solar or other renewable based technologies – each of which has its own cost structure.

[44] Aguiar, A., Chepeliev, M., Corong, E., McDougall, R., & van der Mensbrugghe, D. (2019). The GTAP Data Base: Version 10. *Journal of Global Economic Analysis*, 4(1), 1-27. Retrieved from https://www.jgea.org/ojs/index.php/jgea/article/view/77.

The other key feature of the database is that the cost structure of each industry is also represented in detail. Each industry purchases intermediate inputs (from domestic and imported sources) primary factors (labour, capital, land and natural resources) as well as paying taxes or receiving subsidies.

Table F.1 Standard sectors in the Tasman Global CGE model

no	Name	no	Name
1	Paddy rice	39	Diesel (incl. nonconventional diesel)
2	Wheat	40	Other petroleum, coal products
3	Cereal grains nec	41	Hydrogen
4	Vegetables, fruit, nuts	42	Chemical, rubber, plastic products
5	Oil seeds	43	Iron ore
6	Sugar cane, sugar beet	44	Bauxite
7	Plant- based fibres	45	Mineral products nec
8	Crops nec	46	Ferrous metals
9	Bovine cattle, sheep, goats, horses	47	Alumina
10	Pigs	48	Primary aluminium
11	Animal products nec	49	Metals nec
12	Raw milk	50	Metal products
13	Wool, silk worm cocoons	51	Motor vehicle and parts
14	Forestry	52	Transport equipment nec
15	Fishing	53	Electronic equipment
16	Brown coal	54	Machinery and equipment nec
17	Black coal	55	Manufactures nec
18	Oil	56	Electricity generation
19	LNG	57	Electricity transmission and distribution
20	Other natural gas	58	Gas manufacture, distribution
21	Minerals nec	59	Water
22	Bovine meat products	60	Construction
23	Pig meat products	61	Trade
24	Meat products nec	62	Road transport
25	Vegetables oils and fats	63	Rail and pipeline transport
26	Dairy products	64	Water transport
27	Processed rice	65	Air transport
28	Sugar	66	Transport nec
29	Food products nec	67	Warehousing and support activities
30	Wine	68	Communication
31	Beer	69	Financial services nec
32	Spirits and RTDs	70	Insurance
33	Other beverages and tobacco products	71	Business services nec
34	Textiles	72	Recreational and other services
35	Wearing apparel	73	Public Administration and Defence
36	Leather products	74	Education
37	Wood products	75	Human health and social work activities
38	Paper products, publishing	76	Dwellings

Note: nec = not elsewhere classified.

Source: ACIL Allen

F.3 Model structure

Given its heritage, the structure of the *Tasman Global* model closely follows that of the GTAP and GTEM models and interested readers are encouraged to refer to the documentation of these models for more detail.[45] In summary:

- The model divides the world into a variety of regions and international waters.
  - Each region is fully represented with its own 'bottom-up' social accounting matrix and could be a local community, an LGA, state, country or a group of countries. The number of regions in a given simulation depends on the database aggregation. Each region consists of households, a government with a tax system, production sectors, investors, traders and finance brokers.
  - 'International waters' are a hypothetical region in which global traders operate and use international shipping services to ship goods from one region to the other. It also houses an international finance 'clearing house' that pools global savings and allocates the fund to investors located in every region.
  - Each region has a 'regional household'[46] that collects all factor payments, taxes, net foreign borrowings, net repatriation of factor incomes due to foreign ownership and any net income from trading of emission permits.
- The income of the regional household is allocated across private consumption, government consumption and savings according to a Cobb-Douglas utility function, which, in practice, means that the share of income going to each component is assumed to remain constant in nominal terms.
- Private consumption of each commodity is determined by maximising utility subject to a Constant Difference of Elasticities (CDE) function which includes both price and income elasticities.
- Government consumption of each commodity is determined by maximising utility subject to a Cobb-Douglas utility function.
- Each region has *n* production sectors, each producing single products using various production functions where they aim to maximise profits (or minimise costs) and take all prices as given. The nature of the production functions chosen in the model means that producers exhibit constant returns to scale.
  - In general, each producer supplies consumption goods by combining an aggregate energy-primary factor bundle with other intermediate inputs and according to a Leontief production function (which in practice means that the quantity shares remain in fixed proportions). Within the aggregate energy-primary factor bundle, the individual energy commodities and primary factors are combined using a nested Constant Elasticity of Substitution (CES) production function, in which energy and primary factor aggregates substitute according to a CES function with the individual energy commodities and individual primary factors substituting with their respective aggregates according to further CES production functions.
  - Exceptions to the above include the electricity generation, iron and steel and road transport sectors. These sectors employ the 'technology bundle' approach developed by ABARE[47] in which non-homogenous technologies are employed to produce a homogenous output with the choice of technology governed by minimising costs according to a modified Constant Ratios of Elasticities of Substitution, Homothetic (CRESH) production function. For example, electricity may be generated from a variety of

[45] Namely Hertel, T. (1997). Op. cit. and Pant, H.M. (2007). Op. cit., respectively.

[46] The term "regional household" was devised for the GTAP model. In essence it is an agent that aggregates all incomes attributable to the residents of a given region before distributing the funds to the various types of regional consumption (including savings).

[47] Hanslow, K. & Hinchy, M. (1996). Op. cit.

technologies (including brown coal, black coal, gas, nuclear, hydro, solar etc.), iron and steel may be produced from blast furnace or electric arc technologies while road transport services may be supplied using a range of different vehicle technologies. The 'modified-CRESH' function differs from the traditional CRESH function by also imposing the condition that the quantity units are homogenous.

— There are four primary factors (land, labour, mobile capital and fixed capital). While labour and mobile capital are used by all production sectors, land is only used by agricultural sectors while fixed capital is typically employed in industries with natural resources (such as fishing, forestry and mining) or in selected industries built by ACIL Allen.
  — Land supply in each region is typically assumed to remain fixed through time with the allocation of land between sectors occurring to maximise returns subject to a Constant Elasticity of Transformation (CET) utility function.
  — Mobile capital accumulates as a result of net investment. It is implicitly assumed in *Tasman Global* that it takes one year for capital to be installed. Hence, supply of capital in the current period depends on the last year's capital stock and investments made during the previous year.
  — Labour supply in each year is determined by endogenous changes in population, given participation rates and a given unemployment rate. In policy scenarios, the supply of labour is positively influenced by movements in the real wage rate governed by the elasticity of supply. For countries where sub-regions have been specified (such as Australia), migration between regions is induced by changes in relative real wages with the constraint that net interregional migration equals zero. For regions where the labour market has been disaggregated to include occupations, there is limited substitution allowed between occupations by individuals supplying labour (according to a CET utility function) and by firms demanding labour (according to a CES production function) based on movements in relative real wages.
  — The supply of fixed capital is given for each sector in each region.

  The model has the option for these assumptions to be changed at the time of model application if alternative factor supply behaviours are considered more relevant.

— It is assumed that labour (by occupation) and mobile capital are fully mobile across production sectors implying that, in equilibrium, wage rates (by occupation) and rental rates on capital are equalised across all sectors within each region. To a lesser extent, labour and capital are mobile between regions through international financial investment and migration, but this sort of mobility is sluggish and does not equalise rates of return across regions.

— For most international regions, for each consumer (private, government, industries and the local investment sector), consumption goods can be sourced either from domestic or imported sources. In any country that has disaggregated regions (such as Australia), consumption goods can also be sourced from other intrastate or interstate regions. In all cases, the source of non-domestically produced consumption goods is determined by minimising costs subject to a CRESH utility function. Like most other CGE models, a CES demand function is used to model the relative demand for domestically produced commodities versus non-domestically produced commodities. The elasticities chosen for the CES and CRESH demand functions mean that consumers in each region have a higher preference for domestically produced commodities than non-domestic commodities and a higher preference for intrastate- or interstate-produced commodities than foreign commodities.

— The capital account in *Tasman Global* is open. Domestic savers in each region purchase 'bonds' in the global financial market through local 'brokers' while investors in each region sell bonds to the global financial market to raise investible funds. A flexible global interest rate clears the global financial market.

— It is assumed that regions may differ in their risk characteristics and policy configurations. As a result, rates of return on money invested in physical capital may differ between regions and therefore may be different from the global cost of funds. Any difference between the local rates of return on capital and the global cost of borrowing is treated as the result of the existence of a risk premium and policy imperfections in the international capital market. It is maintained that the equilibrium allocation of investment requires the equalisation of changes in (as opposed to the absolute levels of) rates of return over the base year rates of return.

— Any excess of investment over domestic savings in a given region causes an increase in the net debt of that region. It is assumed that debtors service the debt at the interest rate that clears the global financial market. Similarly, regions that are net savers gives rise to interest receipts from the global financial market at the same interest rate.

— Investment in each region is used by the regional investor to purchase a suite of intermediate goods according to a Leontief production function to construct capital stock with the regional investor cost minimising by choosing between domestic, interstate and imported sources of each intermediate good via the CRESH production function. The regional cost of creating new capital stock versus the local rates of return on mobile capital is what determines the regional rate of return on new investment.

— In equilibrium, exports of a good from one region to the rest of world are equal to the import demand for that good in the remaining regions. Together with the merchandise trade balance, the net payments on foreign debt add up to the current account balance. *Tasman Global* does not require that the current account be in balance every year. It allows the capital account to move in a compensatory direction to maintain the balance of payments. The exchange rate provides the flexibility to keep the balance of payments in balance.

— Detailed bilateral transport margins for every commodity are specified in the starting database. By default, the bilateral transport mode shares are assumed to be constant, with the supply of international transportation services by each region solved by a cost-minimising international trader according to a Cobb-Douglas demand function.

— Emissions of six anthropogenic greenhouse gases (namely, carbon dioxide, methane, nitrous oxide, HFCs, PFCs and SF_6) associated with economic activity are tracked in the model. Almost all sources and sectors are represented; emissions from agricultural residues and land-use change and forestry activities are not explicitly modelled but can be accounted for externally. Prices can be applied to emissions which are converted to industry-specific production taxes or commodity-specific sales taxes that impact on demand. Abatement technologies similar to those adopted in a report released by the Commonwealth Government (2008) are available and emission quotas can be set globally or by region along with allocation schemes that enable emissions to be traded between regions.[48]

More detail regarding specific elements of the model structure is discussed in the following sections.

F.4 Population growth and labour supply

Population growth is an important determinant of economic growth through the supply of labour and the demand for final goods and services. Population growth for each region represented in the *Tasman Global* database is projected using ACIL Allen's in-house demographic model. The demographic model projects how the population in each region grows and how age and gender composition changes over time and is an important tool for determining the changes in regional labour supply and total population over the projected period.

For each of region, the model projects the changes in age-specific birth, mortality and net migration rates by gender for 101 age cohorts (0-99 and 100+). The demographic model also projects

[48] Australian Government (2008), *Australia's Low Pollution Future: the economics of climate change mitigation*, Australian Government, Canberra.

changes in participation rates by gender by age for each region, and, when combined with the age and gender composition of the population, endogenously projects the future supply of labour in each region. Changes in life expectancy are a function of income per person as well as assumed technical progress on lowering mortality rates for a given income (for example, reducing malaria-related mortality through better medicines, education, governance etc.). Participation rates are a function of life expectancy as well as expected changes in higher education rates, fertility rates and changes in the work force as a share of the total population.

Labour supply is derived from the combination of the projected regional population by age by gender and regional participation rates by age by gender. Over the projected period labour supply in most developed economies is projected to grow slower than total population because of ageing population effects.

For the Australian states and territories, the projected aggregate labour supply from ACIL Allen's demographic module is used as the base level potential workforce for the detailed Australian labour market module, which is described in the next section.

F.5 The Australian labour market

Tasman Global has a detailed representation of the Australian labour market which has been designed to capture:

- different occupations
- changes to participation rates (or average hours worked) due to changes in real wages
- changes to unemployment rates due to changes in labour demand
- limited substitution between occupations by the firms demanding labour and by the individuals supplying labour, and
- limited labour mobility between states and regions within each state.

Tasman Global recognises 97 different occupations within Australia – although the exact number of occupations depends on the aggregation. The firms that hire labour are provided with some limited scope to change between these 97 labour types as the relative real wage between them changes. Similarly, the individuals supplying labour have a limited ability to change occupations in response to the changing relative real wage between occupations. Finally, as the real wage for a given occupation rises in one state relative to other states, workers are given some ability to respond by shifting their location. The model produces results at the 97 3-digit Australian New Zealand Standard Classification of Occupations (ANZSCO) level which are presented in Table F.2.

The labour market structure of *Tasman Global* is thus designed to capture the reality of labour markets in Australia, where supply and demand at the occupational level do adjust, but within limits.

Labour supply in *Tasman Global* is presented as a three-stage process:

1. labour makes itself available to the workforce based on movements in the real wage and the unemployment rate
2. labour chooses between occupations in a state based on relative real wages within the state
3. labour of a given occupation chooses in which state to locate based on movements in the relative real wage for that occupation between states.

By default, *Tasman Global*, like all CGE models, assumes that markets clear. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model).

Table F.2 Occupations in the Tasman Global database, ANZSCO 3-digit level (minor groups)

ANZSCO code, Description	ANZSCO code, Description	ANZSCO code, Description
1. MANAGERS 111 Chief Executives, General Managers and Legislators 121 Farmers and Farm Managers 131 Advertising and Sales Managers 132 Business Administration Managers 133 Construction, Distribution and Production Managers 134 Education, Health and Welfare Services Managers 135 ICT Managers 139 Miscellaneous Specialist Managers 141 Accommodation and Hospitality Managers 142 Retail Managers 149 Miscellaneous Hospitality, Retail and Service Managers **2. PROFESSIONALS** 211 Arts Professionals 212 Media Professionals 221 Accountants, Auditors and Company Secretaries 222 Financial Brokers and Dealers, and Investment Advisers 223 Human Resource and Training Professionals 224 Information and Organisation Professionals 225 Sales, Marketing and Public Relations Professionals 231 Air and Marine Transport Professionals 232 Architects, Designers, Planners and Surveyors 233 Engineering Professionals 234 Natural and Physical Science Professionals 241 School Teachers 242 Tertiary Education Teachers 249 Miscellaneous Education Professionals 251 Health Diagnostic and Promotion Professionals 252 Health Therapy Professionals 253 Medical Practitioners 254 Midwifery and Nursing Professionals 261 Business and Systems Analysts, and Programmers 262 Database and Systems Administrators, and ICT Security Specialists 263 ICT Network and Support Professionals 271 Legal Professionals 272 Social and Welfare Professionals	**3. TECHNICIANS & TRADES WORKERS** 311 Agricultural, Medical and Science Technicians 312 Building and Engineering Technicians 313 ICT and Telecommunications Technicians 321 Automotive Electricians and Mechanics 322 Fabrication Engineering Trades Workers 323 Mechanical Engineering Trades Workers 324 Panel beaters, and Vehicle Body Builders, Trimmers and Painters 331 Bricklayers, and Carpenters and Joiners 332 Floor Finishers and Painting Trades Workers 333 Glaziers, Plasterers and Tilers 334 Plumbers 341 Electricians 342 Electronics and Telecommunications Trades Workers 351 Food Trades Workers 361 Animal Attendants and Trainers, and Shearers 362 Horticultural Trades Workers 391 Hairdressers 392 Printing Trades Workers 393 Textile, Clothing and Footwear Trades Workers 394 Wood Trades Workers 399 Miscellaneous Technicians and Trades Workers **4. COMMUNITY & PERSONAL SERVICE** 411 Health and Welfare Support Workers 421 Child Carers 422 Education Aides 423 Personal Carers and Assistants 431 Hospitality Workers 441 Defence Force Members, Fire Fighters and Police 442 Prison and Security Officers 451 Personal Service and Travel Workers 452 Sports and Fitness Workers	**5. CLERICAL & ADMINISTRATIVE** 511 Contract, Program and Project Administrators 512 Office and Practice Managers 521 Personal Assistants and Secretaries 531 General Clerks 532 Keyboard Operators 541 Call or Contact Centre Information Clerks 542 Receptionists 551 Accounting Clerks and Bookkeepers 552 Financial and Insurance Clerks 561 Clerical and Office Support Workers 591 Logistics Clerks 599 Miscellaneous Clerical and Administrative Workers **6. SALES WORKERS** 611 Insurance Agents and Sales Representatives 612 Real Estate Sales Agents 621 Sales Assistants and Salespersons 631 Checkout Operators and Office Cashiers 639 Miscellaneous Sales Support Workers **7. MACHINERY OPERATORS & DRIVERS** 711 Machine Operators 712 Stationary Plant Operators 721 Mobile Plant Operators 731 Automobile, Bus and Rail Drivers 732 Delivery Drivers 733 Truck Drivers 741 Store persons **8. LABOURERS** 811 Cleaners and Laundry Workers 821 Construction and Mining Labourers 831 Food Process Workers 832 Packers and Product Assemblers 839 Miscellaneous Factory Process Workers 841 Farm, Forestry and Garden Workers 851 Food Preparation Assistants 891 Freight Handlers and Shelf Fillers 899 Miscellaneous Labourers

Source: ABS (2009), ANZSCO – Australian and New Zealand Standard Classifications Of Occupations, First edition, Revision 1, ABS catalogue no. 1220.0.

The *Tasman Global* database includes a detailed representation of the Australian labour market that has been designed to capture the supply and demand for different skills and occupations by industry. To achieve this, the Australian workforce is characterised by detailed supply and demand matrices.

On the supply side, the Australian population is characterised by a five-dimensional matrix consisting of:

— 7 post-school qualification levels
— 12 main qualification fields of highest educational attainment
— 97 occupations
— 101 age groups (namely 0 to 99 and 100+)
— 2 genders.

The data for this matrix is measured in persons and was sourced from the ABS 2011 Census. As the skills elements of the database and model structure have not been used for this project, it will be ignored in this discussion.

The 97 occupations are those specified at the 3-digit level (or Minor Groups) under the ANZSCO (see Table F.2).

On the demand side, each industry demands a particular mix of occupations. This matrix is specified in units of FTE jobs where an FTE employee works an average of 37.5 hours per week. Consistent with the labour supply matrix, the data for FTE jobs by occupation by industry was also sourced from the ABS 2011 Census and updated using the latest labour force statistics.

Matching the demand and supply side matrices means that there is the implicit assumption that the average hours per worker are constant, but it is noted that mathematically changes in participation rates have the same effect as changes in average hours worked.

F.6 Labour market model structure

In the model, the underlying growth of each industry in the Australian economy results in a growth in demand for a particular set of skills and occupations. In contrast, the supply of each set of skills and occupations in a given year is primarily driven by the underlying demographics of the resident population. This creates a market for each skill by occupation that (unless specified otherwise) needs to clear at the start and end of each time period.[49] The labour markets clear by a combination of different prices (i.e. wages) for each labour type and by allowing a range of demand and supply substitution possibilities, including:

— changes in firms' demand for labour driven by changes in the underlying production technology
  – for technology bundle industries (electricity, iron and steel and road transportation) this occurs due to changes between explicitly identified alternative technologies
  – for non-technology bundle industries this includes substitution between factors (such as labour for capital) or energy for factors
— changes to participation rates (or average hours worked) due to changes in real wages
— changes in the occupations of a person due to changes in relative real wages
— substitution between occupations by the firms demanding labour due to changes in the relative costs
— changes to unemployment rates due to changes in labour demand, and
— limited labour mobility between states due to changes in relative real wages.

All of the labour supply substitution functions are modified-CET functions in which people supply their skills, occupation and rates of participation as a positive function of relative wages. However,

[49] For example, at the start and end of each week for this analysis. *Tasman Global* can be run with different steps in time, such as quarterly or bi-annually in which case the markets would clear at the start and end of these time points.

unlike a standard CET (or CES) function, the functions are 'modified' to enforce an additional constraint that the number of people is maintained before and after substitution.[50]

Although technically solved simultaneously, the labour market in *Tasman Global* can be thought of as a 5-stage process:

— labour makes itself available to the workforce based on movements in the real wage (that is, it actively participates with a certain number of average hours worked per week)
— the age, gender and occupations of the underlying population combined with the participation rate by gender by age implies a given supply of labour (the potentially available workforce)
— a portion of the potentially available workforce is unemployed, implying a given available labour force
— labour chooses to move between occupations based on relative real wages
— industries alter their demands for labour as a whole and for specific occupations based on the relative cost of labour to other inputs and the relative cost of each occupation.

By default, *Tasman Global*, like all CGE models, assumes that markets clear at the start and end of each period. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model). In principle, (subject to zero starting values) people of any age and gender can move between any of the 97 occupations while industries can produce their output with any mix of occupations. However, in practice the combination of the initial database, the functional forms, low elasticities and moderate changes in relative prices for skills, occupations etc. means that there is only low to moderate change induced by these functions. The changes are sufficient to clear the markets, but not enough to radically change the structure of the workforce in the timeframe of this analysis.

Factor-factor substitution elasticities in non-technology bundle industries are industry specific and are the same as those specified in the GTAP database[51], while the fuel-factor and technology bundle elasticities are the same as those specified in GTEM.[52] The detailed labour market elasticities are ACIL Allen assumptions, previously calibrated in the context of the model framework to replicate the historical change in the observed Australian labour market over a five year period[53]. The unemployment rate function in the policy scenarios is a non-linear function of the change in the labour demand relative to the base case with the elasticity being a function of the unemployment rate (that is, the lower the unemployment rate the lower the elasticity and the higher the unemployment rate the higher the elasticity).

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[50] As discussed in Dixon et al (1997), a standard CES/CET function is defined in terms of *effective units*. Quantitatively this means that, when substituting between, say, X_1 and X_2 to form a total quantity X using a CET function a simple summation generally does not actually equal X. Use of these functions is common practice in CGE models when substituting between substantially different units (such as labour versus capital or imported versus domestic services) but was not deemed appropriate when tracking the physical number of people. Such 'modified' functions have long been employed in the technology bundles of *Tasman Global* and GTEM. The Productivity Commission have proposed alternatives to the standard CES to overcome similar and other weaknesses when applied to internationally traded commodities. See Dixon, P.B., Parmenter, B., Sutton, J., & Vincent, D. (1997), *ORANI: A Multisectoral Model of the Australian Economy*, Amsterdam: North Holland.

[51] Narayanan et al. (2012).

[52] Pant, H.M. (2007), GTEM: *Global Trade and Environment Model*, ABARE Technical Report, Canberra, June.

[53] This method is a common way of calibrating the economic relationships assumed in CGE models to those observed in the economy. See for example Dixon, P.B. and Rimmer, M.T. (2002), *Dynamic General Equilibrium Modelling for Forecasting and Policy*. Contributions to Economic Analysis 256, Amsterdam: North Holland.

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APGA Submission

Electricity and Energy Sector Plan Consultation

26 April 2024

Contents

List of Figures

List of Tables

Executive Summary

The Electricity and Energy Sector Plan (EESP) Discussion Paper is clear in its framing – Australia needs alternative low carbon fuels to achieve its emission reduction goals. Alternative low carbon fuels such as renewable gases and renewable liquid fuels are a critical part of the renewable energy ecosystem. Policy support for these new forms of renewable energy has been insufficient across the past decade and this must be addressed as a matter of urgency if Australia is to meet its climate ambition.

The Australian Pipelines and Gas Association (APGA) supports the intent of the EESP to explore policy support for alternative low carbon fuels. Decarbonising existing fuel supply ensures all energy customers can decarbonise and is key to a future made in Australia. Gas power generation (GPG) will also play a vital role in firming renewable generation on the pathway net zero electricity supply.

When considering policy support, the Federal Government can learn from the policies which have worked to enable electricity decarbonisation. Certification and NGER recognition, target setting and contract for difference schemes have driven the energy transition to date and provide an excellent basis for its acceleration through gas and liquid fuels and GPG support.

Decarbonising gas and liquid fuel supply

Decarbonising gas and liquid fuels is critical for the economy. Gas accounts for 24% of all end-use energy consumption in Australia and is a critical input to Australian industry, mining and manufacturing.

Low-cost gas transport and storage infrastructure and low-cost gas appliances are part of the reason customers choose natural gas today. These low-cost advantages are also available to the renewable gas supply chain as it develops:

- Existing gas infrastructure costs less than electricity infrastructure, can deliver biomethane today, and can deliver 100% hydrogen with minimal additional cost[1].
- New renewable gas transport and storage infrastructure cost less than new electricity transport infrastructure and mature electricity storage options[1].
- Biomethane and hydrogen appliances cost less than their electric equivalents[1].

Some gas customers will have no option other than to decarbonise via renewable gas. Economic analysis by ACIL Allen indicates a minimum of 210PJpa of renewable gas is required to decarbonise industrial gas customers alone. More than this will be required to enable future expansion of Australian manufacturing and the production of green export products.

The policy focus areas identified for liquid fuels in Section 4.7 of the consultation paper can also be applied to decarbonising gas supply. The table below maps these policy focus areas to the gas supply chain. Consideration of renewable gas policy opportunities within this framework shows that in some regards, policy change to enable renewable gases is already underway. However, further policy support to decarbonise our gaseous fuel mix is required.

[1] See Section 1.1 of this submission for further details.

Table E1. Renewable gas policy focus areas and associated policy actions

Policy focus areas	1. Decarbonise our gaseous fuel mix	2. Reduce fossil gas demand	3. Ensure gas security and reliability	4. Manage supply chain vulnerabilities
Reason:	Driving renewable gases supports decarbonisation efforts and de-risks gas supply through diversification	Improving energy efficiency and promoting behavioural change reduces emissions and gas demand	Leveraging existing gas security and reliability of supply legislation will ensure climate and energy objectives are met through the transition	Existing mechanisms to address gas supply chain disruptions ensures government and industry can quickly respond to emerging gas supply chain risks
Renewable Gas Policy Action:	- An NGER market-based accounting method for gas emissions - A National Renewable gas target as part of the Future Gas Strategy (FGS) - Federal contracts for difference for renewable gas supply	- Increase gas appliance efficiency floor via existing NEPS process [UNDERWAY[2]]	- Expand existing gas security and reliability of supply legislation to cover renewable gases [COMPLETED[2]]	- Expand existing mechanisms to address gas supply chain disruptions to renewable gases [COMPLETED[2]]

Gas enables net zero electricity in Australia

Today's gas supply chain helps keep electricity prices low and reliability and security high. It does so by fuelling GPG and taking much of Australia's seasonally variable energy load off the electricity grid – most of Australia's winter heating is powered by gas. Gas can continue to support electricity reliability and security as both energy systems decarbonise together. However, policy support is required.

The Draft 2024 ISP clearly sets out the role of GPG in a decarbonised National Electricity Market:

> *As Australia's coal-fired generators retire after decades of service, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation (GPG) is the lowest cost way to supply electricity to homes and businesses.*[3]

Despite this, GPG is excluded from the Capacity Investment Scheme (CIS). This impedes the investment in GPG needed to secure the lowest cost pathway to 82% renewable electricity supply according to AEMO.

GPG support aside, policy support to enable renewable gas supply will support a decarbonising gas system, in turn reducing the load on a future net zero NEM.

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[2] See Section 1.3 of this submission for further details.

[3] AEMO, 2024, *Draft 2024 Integrated Systems Plan*, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/draft-2024-isp.pdf

Policy recommendations

APGA recommends the Department undertake modelling on the least cost pathway to gas use decarbonisation in Australia to inform renewable gas policy. Based upon industry analysis and AEMO recommendations relating to GPG, APGA proposes four policy recommendations across the immediate and medium term.

Immediate term policy recommendations

Policy action APGA recommends the EESP identifies for immediate action:

NGER market-based method for gas emissions accounting
GreenPower renewable gas certificates are being issued today, but NGER does not recognise these. Recognising GreenPower and future renewable gas certificates in NGER emissions accounting is critical to unlocking tens of petajoules of renewable gas production projects reaching FID in the near term.

GPG support via the CIS or analogous support mechanism
Extend the CIS to include GPG or develop a similar scheme to provide the long-term investment signals necessary to support investment in GPG capacity.

Medium term policy recommendations

Policy action APGA recommends the EESP identifies for medium term action:

A national Renewable Gas Target
Targeting the least cost pathway to net zero gas sets national gas decarbonisation ambition and strong industrial reliance on renewable gas makes a national RGT no-regrets policy.

Contracts for Difference for renewable gas supply
Renewable gas certification and recognition in NGER is the first step in starting a renewable gas industry today. The Hydrogen Headstart program is an excellent start but more must be done to ensure availability of large volumes of renewable gas including biomethane. Renewable gas Contract for Difference schemes could be used to ensure the cost of biomethane does not exceed the cost of natural gas for consumers today.

To discuss any of the details within this submission further, please contact APGA's National Policy Manager, Jordan McCollum, on +61 422 057 856 or jmccollum@apga.org.au.

About

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure, connecting natural and renewable gas production to demand centres in cities and other locations across Australia. Offering a wide range of services to gas users, retailers and producers, APGA members ensure the safe and reliable delivery of 28 per cent of the end-use energy consumed in Australia and are at the forefront of Australia's renewable gas industry, helping achieve net-zero as quickly and affordably as possible.

APGA supports a net zero emission future for Australia by 2050[4]. Renewable gases represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. As set out in Gas Vision 2050[5], APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC[6], which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy to homes, businesses, and industry throughout Australia.

[4] APGA, *Climate Statement*, available at: https://www.apga.org.au/apga-climate-statement
[5] APGA, 2020, *Gas Vision 2050*, https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[6] Future Fuels CRC: https://www.futurefuelscrc.com/

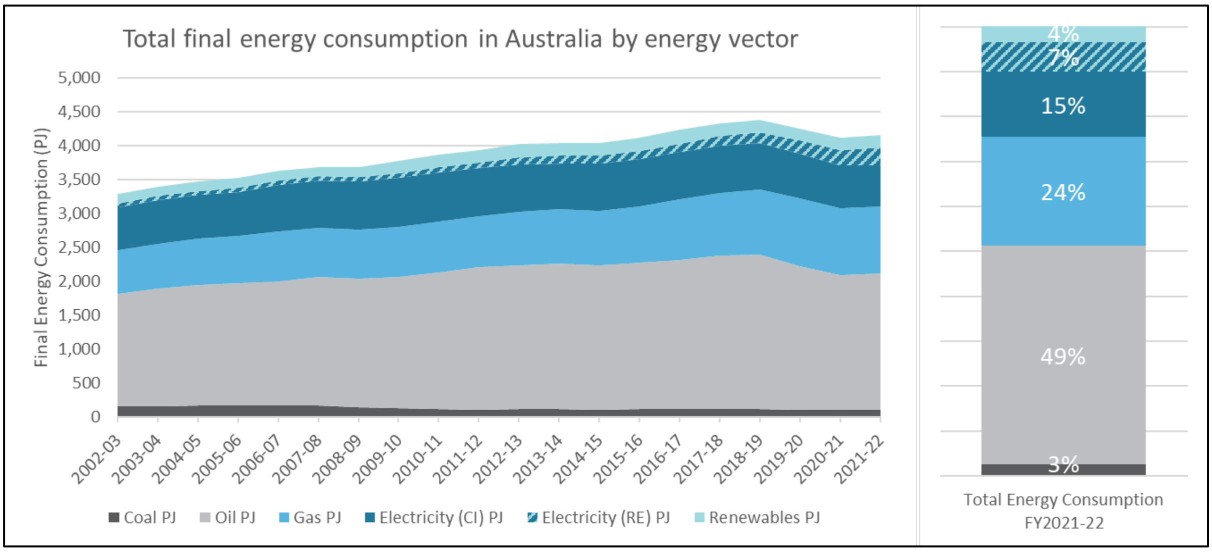
1 Decarbonising gas and liquid fuel supply

The EESP Discussion Paper takes Australia forward in its energy decarbonisation journey by committing an entire section to alternative low carbon fuels. Doing so highlights the need to decarbonise gas and liquid fuel supply chains. While both energy types are on their own decarbonisation journeys, similarities between the two mean that learnings from the decarbonisation of one can inform how best to decarbonise the other.

Over 75% of Australia's energy demand is consumed directly as fossil fuels[7] (Figure 1). Many of these direct fuel consuming energy customers are unable to electrify their energy demand – and a majority of these are the industrial energy customers upon which the Australian economy relies[8]. Gas and liquid fuel supply have renewable alternatives that must be deployed to achieve net zero:

- Natural gas has renewable gas alternatives such as biomethane and hydrogen.
- Liquid fuels have renewable liquid fuel alternatives such as bioethanol and renewable diesel.

Figure 1: Total final energy consumption in Australia by energy vector[9]



Accelerating the decarbonisation of existing gas and liquid fuel energy supply chains via alternative low carbon fuels will ensure these energy customers remain part of the Australian economy. They can continue to mine our resources, process our materials, make our products, and provide the jobs and economic activity that keeps the Australian economy vibrant and successful. Section 1.1 shows that the ability to use the lower cost infrastructure and appliances to transport, store and use fuels can help reduce the cost of an otherwise electricity – only energy transition.

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[7] DCCEEW, 2023, *Australian Energy Update 2023*, https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Update%202023_0.pdf

[8] Grattan Institute, 2021, *Towards net zero: Practical policies for reducing industrial emissions*, https://grattan.edu.au/wp-content/uploads/2021/08/Towards-net-zero-Practical-policies-to-reduce-industrial-emissions-Grattan-report.pdf

[9] DCCEEW, 2023, *Australian Energy Update 2023*.

Robust renewable fuels supply chains support a more secure and reliable energy system in a net zero future[10]. This makes renewable fuels essential to underpinning a future made in Australia. Secure and reliable carbon neutral energy of all forms will be required to re-align Australia's economy towards carbon neutral advanced manufacturing. Without a competitive supply of renewable fuels, Australia risks significant carbon leakage as industry chooses to relocate rather than decarbonise.

Beyond achieving net zero for today's gas customers, putting gas supply on its own decarbonisation journey also enables broader decarbonisation in the immediate term. Once gas is on a pathway to net zero, existing coal and liquid fuel customers can achieve immediate short-term emission reductions by transitioning to natural gas today, knowing natural gas will transition to renewable gas tomorrow.

This makes coal and liquid fuel emissions reduction cheaper and easier in the near term, accelerating decarbonisation in the decade to 2035. An example of this can be seen in BlueScope, Rio Tinto and BHP pursuing Direct Reduced Iron (DRI) technologies to replace coal supply in the short term with natural gas, and in the long term with hydrogen[11] (Figure 2). BHP is also transitioning from diesel to gas powered generation to firm variable renewable generation[12]. The opportunity to more rapidly decarbonise beyond today's gas customers makes renewable gases a priority within the EESP.

Figure 2: Excerpt from BlueScope 2023 Sustainability Report

Iron and steelmaking transformation

BlueScope's indicative decarbonisation pathway has been updated to reflect our refreshed assessment of technology developments in DRI, using natural gas as a transitional step to green hydrogen to produce lower emissions steel. This assessment was informed by our concept study with Rio Tinto to explore DRI and its application to Australia's Pilbara hematite ores in conjunction with Electric Smelting Furnaces[1](ESF), known as 'Melters'. The study is now complete and the next stage of activity will include trials and a potential pilot program.

Further development of the use of hematite ores in a DRI-ESF process would unlock opportunities for the steel sector and the minerals sector as part of the transition to lower emissions iron and steelmaking, given their abundant availability, compared to higher grade ores typically required for the DRI process.

[10] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context* available at https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/pipelines_vs_powerlines_-_a_technoeconomic_analysis_in_the_australian_context.pdf

[11] Bluescope, 2023, *Sustainability Report FY2023,* https://www.bluescope.com/content/dam/bluescope/corporate/bluescope-com/sustainability/documents/2023_BlueScope_Report_Sustainability_Report.pdf; Fuller K, 2024, 'BlueScope, Rio Tinto and BHP join forces on plan for low carbon steel future', in *ABC News Illawarra*, https://www.abc.net.au/news/2024-02-09/green-steel-push-bluescope-bhp-rio-tinto-join-forces-carbon-plan/103447174

[12] BHP, 2023, *Operational decarbonisation*, https://www.bhp.com/-/media/documents/media/reports-and-presentations/2023/230621_operationaldecarbonisationinvestorbriefing.pdf

1.1 The advantage of gas supply chains

All natural and renewable gas supply chains benefit from the advantages of gas infrastructure and appliances. The simple, flexible nature of pipeline infrastructure makes it a cost-effective way to not only transport energy, but store energy within transmission infrastructure. As a result, natural gas remains lower cost for customers to use today in comparison with other options – even when piped thousands of kilometres across the country.

Similarly, appliances that use natural or renewable gases are cheaper than their alternatives. This lower upfront cost can make up for their energy efficiency which is inherently lower than heat pumps. Higher energy consumption through lower cost appliances can lead to lower cost of energy and appliances combined[13].

These advantages means that renewable gases can not only serve those gas customers with no other decarbonisation choice, but they can do so at a cost competitive with renewable electricity[13]. To understand the cost of decarbonisation for energy customers through alternative low carbon fuels, it is necessary to consider the cost effectiveness of energy transport, storage and appliances alongside the cost effectiveness of energy production.

1.1.1 Existing gas infrastructure

Direct comparison of like-for-like gas and electricity infrastructure demonstrates that gas infrastructure consistently costs less when providing equal or higher supply capacity. This is why gas infrastructure draws lower revenues from customers.

Table 1 and Table 2 below demonstrate comparisons of the regulated asset bases (RABs) of comparable gas and electricity infrastructure in Victoria and the ACT.

Table 1: Costs and deliveries of Victoria's energy infrastructure[14]

Transmission and Distribution Infrastructure	Regulated Asset Base ($m)	Actual Annual Revenues ($m)	Actual Energy Delivered (GWh)	Max Demand Capacity (MW)
Electricity	17,329	2,825	41,480	8,684
Gas	5,631	774	64,722	23,250

[13] Boston Consulting Group, 2023, *The role of gas infrastructure in Australia's energy transition*, https://39713956.fs1.hubspotusercontent-na1.net/hubfs/39713956/The-Role-of-Gas-Infrastrcuture-in-Australia-s-Energy-Transition.pdf
[14] APGA, 2021, *Submission: Victorian Gas Substitution Roadmap Consultation Paper*, https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/210816_apga_submission_to_the_victorian_gas_substitution_roadmap_consultation_paper.pdf

Table 2: Relative cost of energy delivery for gas and electricity distribution in the ACT[15]

Energy distribution networks	Regulated asset base ($m)	Actual annual revenues ($m)	Actual energy delivered (GWh)	Average cost to deliver a GWh ($)
Electricity	981	140	2,851	49,106
Gas	377	67	2,201	30,436

In Victoria, the RAB of gas transmission and distribution infrastructure is a third of the size of that of electricity infrastructure, but delivers a third more energy, and can support peak demand 60% higher. Relevant to customer interests, gas infrastructure also generates only 27% of the revenue of electricity, which is related both to the capital cost of the infrastructure and ongoing operational expenditure. Similarly, ACT gas infrastructure delivers 80% of the capacity of electricity infrastructure at 40% of the cost.

Analysis by the ARENA-funded Australia Hydrogen Centre further shows that the cost of converting gas infrastructure to deliver 100% hydrogen comes at a fraction of gas asset RAB. Analysis on South Australian and Victorian gas distribution networks shows that conversion of the gas network and all gas appliances to 100% hydrogen would increase distribution network stay-in-business capital expenditure to 2050 by 11-12% in present value terms[16]. This small cost of conversion indicates that today's low cost of gas infrastructure will be retained when delivering renewable gases, even hydrogen, through existing gas infrastructure.

1.1.2 New gas infrastructure

Where new energy transport and storage infrastructure is required, pipeline infrastructure is a cost competitive option. This has been shown through recent pipeline and powerline infrastructure projects:

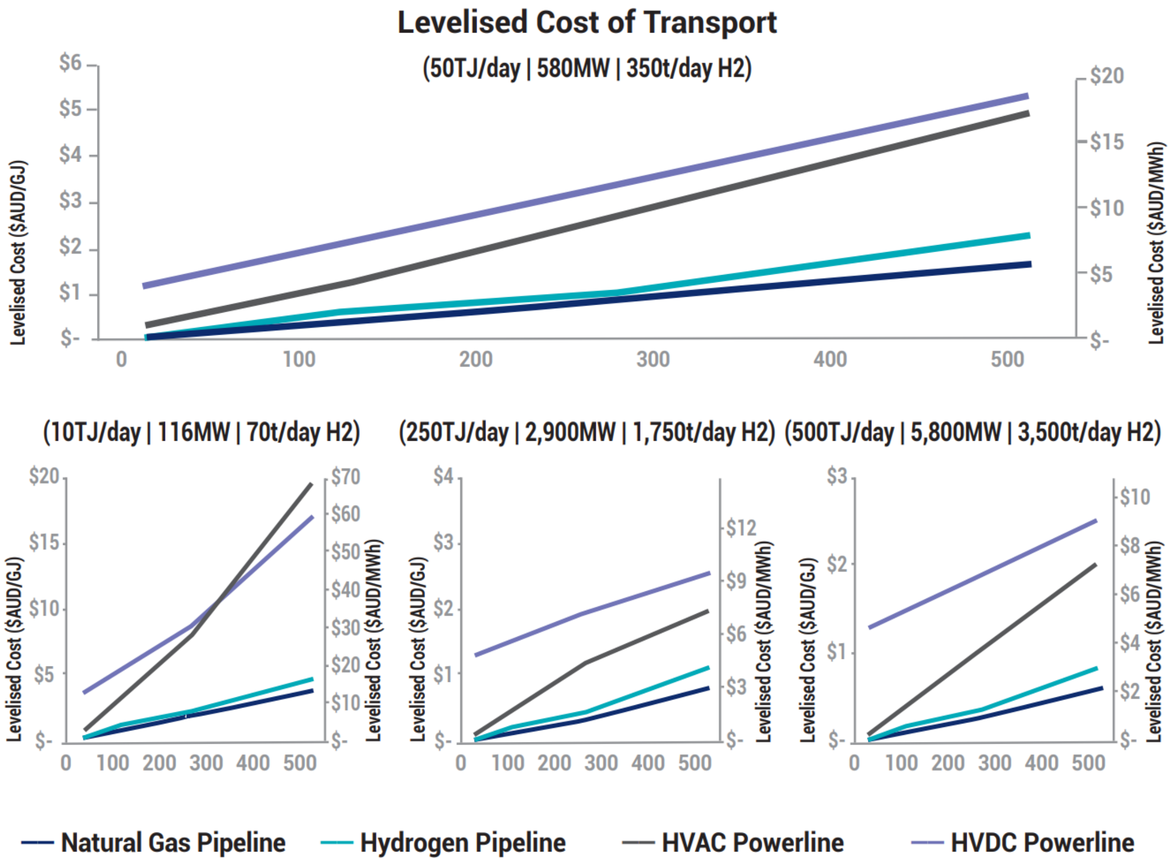
- APA's 50km Western Outer Ring Main pipeline was completed in 2024 for approximately $185 million, or $3.7 million per kilometre. This project was in an urban environment, significantly adding to cost.
- APA's $560km Northern Gas Interconnect was completed in 2023 for a cost of $821,000 per kilometre.
- AGIG's 440km Tanami Natural Gas Pipeline, completed in 2019, cost $346 million or $786,000 per kilometre.

[15] APGA, 2023, *Submission: Regulating for the prevention of new fossil fuel gas network connections*, https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/230420_apga_submission_-_act_gas_connections.pdf
[16] Australian Hydrogen Centre, 2023, *100% Hydrogen Distribution Networks: Victoria Feasibility Study*, https://arena.gov.au/assets/2023/09/AHC-100-Hydrogen-Distribution-Networks-Victoria-Feasibility-Study.pdf; Australian Hydrogen Centre, 2023, *100% Hydrogen Distribution Networks: South Australia Feasibility Study*, https://arena.gov.au/assets/2023/09/AHC-100-Hydrogen-Distribution-Networks-South-Australia-Feasibility-Study.pdf

- The 360km HumeLink overhead transmission powerline project is expected to cost approximately $4.8 billion, or $13.3 million per kilometre.
- The proposed 400km Victoria – New South Wales Interconnector West overhead transmission project is expected to cost approximately $3.3 billion, or $8.25 million per kilometre. There are numerous reports that this cost will increase.

GPA Engineering's *Pipelines vs Powerlines* report provides further details on this relationship[17]. Both gas and hydrogen transmission pipelines consistently cost less to deliver the same quantity of energy across the same distance in comparison to electricity transmission powerlines. An example of this relationship can be seen in Figure 3, outlining the cost of energy transport for a range of energy capacity scenarios over 500km. This outcome has since been supported by academic research within the Future Fuels CRC.

Figure 3: Levelised cost of energy transport via pipelines and powerlines[18]

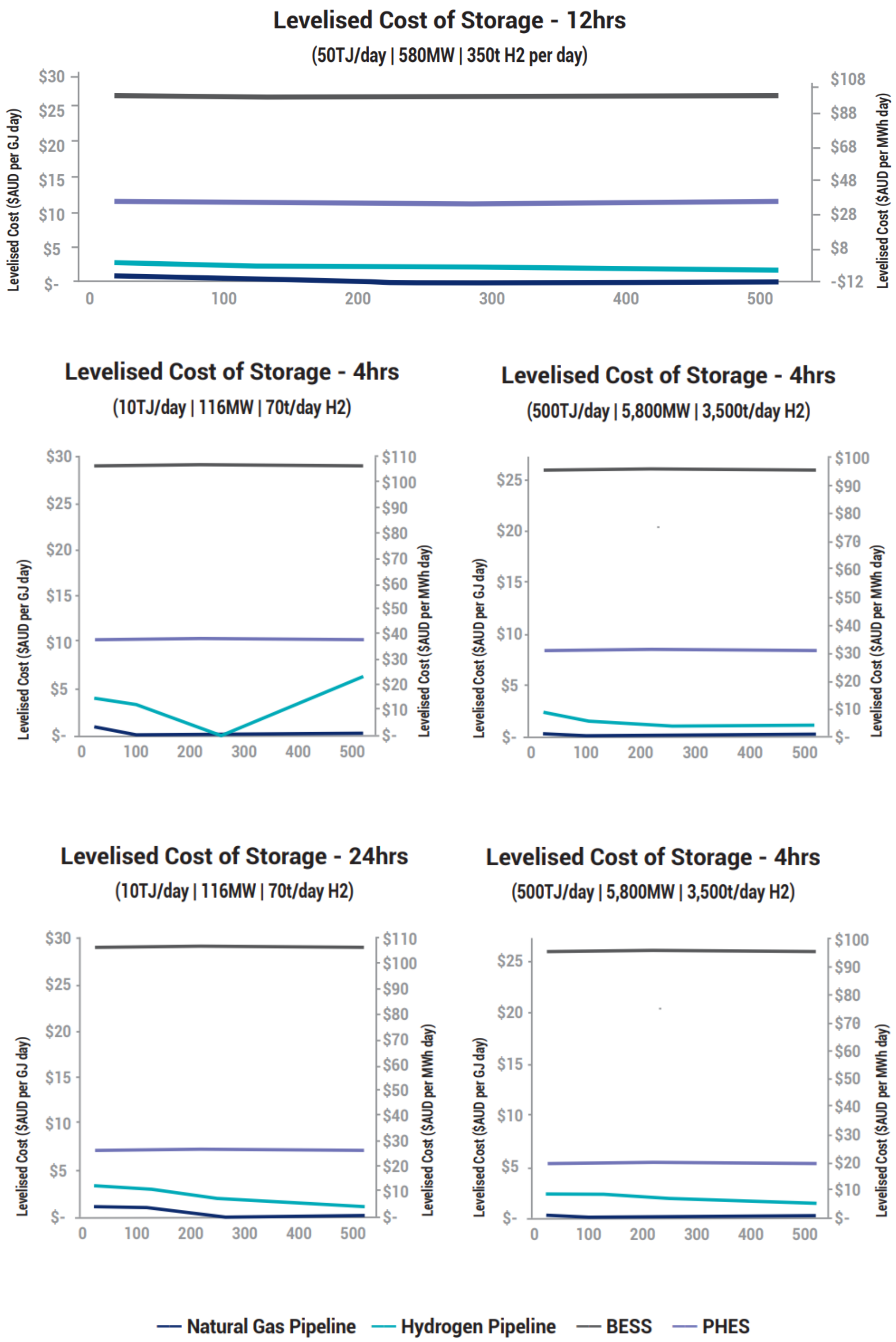


The economic benefits of new pipeline infrastructure extend beyond transport. GPA Engineering's research also examined the levelised cost of energy storage between pipelines and battery (BESS) and pumped hydro (PHES) energy storage solutions, finding that energy storage in pipelines can be hundreds of times cheaper than energy storage in utility scale batteries or pumped hydro (Figure 4). GPA Engineering found that energy

[17] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.
[18] Ibid.

storage in hydrogen pipelines can be 2-to-36 times cheaper than energy storage in utility scale batteries or pumped hydro, excluding the instances in which it is essentially free.

Figure 4: Levelised cost of energy storage via pipeline linepack, BESS and PHES



1.1.3 Gas and hydrogen appliances

The technical simplicity of combusting gas makes gas and hydrogen appliances a cost-effective option in the majority of applications gas is used for today. Collating appliance cost assumptions for its economic analysis, ACIL Allen identified (Figure 5) that gas or hydrogen appliances were the equal or lowest cost appliance option for over three quarters of applications gas use used for today[19].

Considering the cost of decarbonising gas use, both energy cost and appliance cost needs to be taken into account. Focusing on only appliance cost or energy cost could lead to inaccurate conclusions being made about the least cost decarbonisation pathway.

Figure 5: Appliance capital cost and operating life assumptions[20]

Activity (by size)	Capital cost unit basis	Capital cost: Natural gas appliance	Capital cost: Electrical appliance	Capital cost: Hydrogen appliance	Appliance life (years): Gaseous fuels appliance	Appliance life (years): Electrical appliance
Low temperature heat	$\$m/MW_{th}$	0.5	1.3	0.65	20	15
High temperature heat (small)	$\$m/MW_{th}$	0.4	0.4	0.5	25	25
High temperature heat (medium)	$\$m/MW_{th}$	0.3	0.3	0.4	25	25
Metal reheat (small)	$\$m/MW_{th}$	0.5	1.7	0.7	20	15
Metal reheat (medium)	$\$m/MW_{th}$	0.3	1.5	0.4	20	15
Compression (medium)	$m/MW	6.4	7.8	6.4	25	25
Compression (large)	$m/MW	3.5	4.3	3.5	25	25
Glass making	$\$m/MW_{th}$	1.5	1.5	1.6	20	20
Calcining (medium)	$\$m/MW_{th}$	1.5	N/A	1.6	30	30
Calcining (large)	$\$m/MW_{th}$	1.5	N/A	1.6	30	30
Digestion	$\$m/MW_{th}$	0.3	1.7	0.4	20	15
Ammonia synthesis	$m/ktpa (capacity)	1.9	N/A	1.5	25	25
Urea	$m/ktpa (capacity)	2.7	N/A	0.8	25	25
LNG power generation	$m/MW	1.5	0.2	N/A	25	40
Commercial cooking	$\$m/MW_{th}$	0.2	0.3	0.3	20	15
Commercial hot water	$\$m/MW_{th}$	0.8	1.3	0.9	15	15
Commercial space heating	$\$m/MW_{th}$	0.5	0.8	0.5	20	15
Residential cooking - existing	$000/ appliance	2.0	2.7	2.2	20	15
Residential hot water - existing	$000/ appliance	3.2	2.9 (resistive) 5.4 (heat pump)	3.6	15	15

[19] See Attachment 1

[20] See Attachment 1; note there is more appliance cost detail in Attachment 1 then shown in this document.

1.2 Economic analysis of gas use decarbonisation

To assist gas customers to decarbonise, APGA and Energy Networks Australia (ENA) commissioned ACIL Allen to undertake economic analysis of gas use decarbonisation. A copy of the study is attached to this submission and APGA invites further conversation on this study and its implications. This section will explore analysis outcomes for the following topics:

- Renewable gas supply for gas customers which have no option to electrify
- Gas use decarbonisation at lowest overall cost
- Policy to deliver gas use decarbonisation at lowest overall cost.

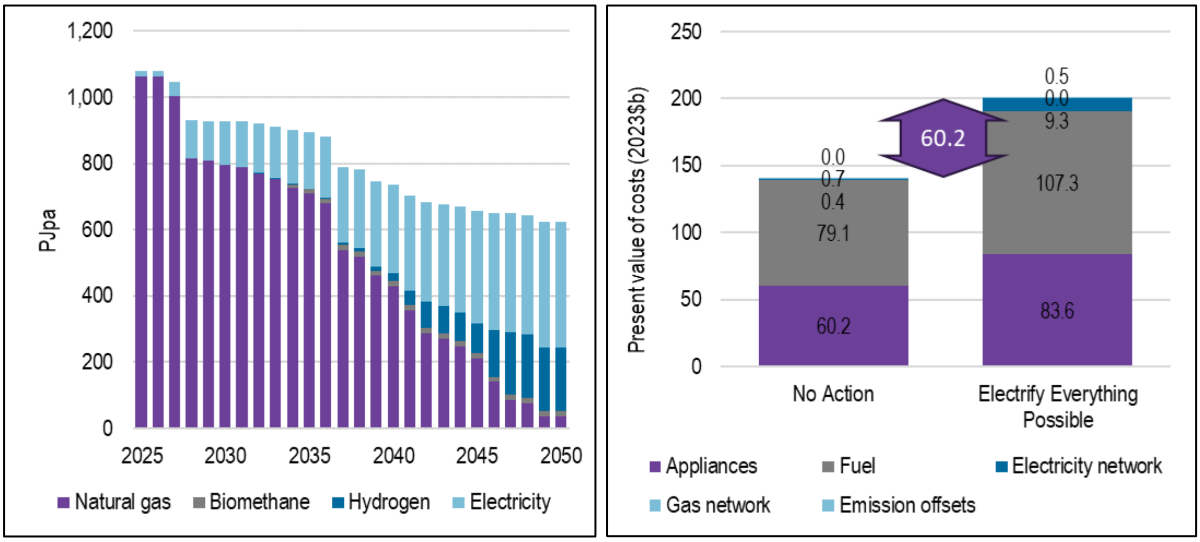
Beyond considering these results, APGA strongly recommends that the Department replicates the modelling approaches seen within this study to assess policy options to deliver gas use decarbonisation at lowest overall cost.

1.2.1 Renewable gas supply for gas customers which cannot electrify

The analysis considered the least cost pathway to decarbonise gas use, while reserving renewable gases for those who cannot electrify. In this Electrify Everything Possible (EEP) scenario, all domestic gas customers which could electrify – i.e. have an electric appliance option – were required to electrify in order to decarbonise. The least cost decarbonisation trajectory was calculated in line with a net zero carbon budget.

Figure 6 below shows that the result is a steady electrification of gas demand over the window to 2050, with 210PJpa worth of renewable gases being required decarbonise customers unable to electrify.

Figure 6: EEP scenario – energy supply breakdown and cost comparison[21]



[21] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, commissioned by APGA and ENA.

This demonstrates that a combination of renewable gas and renewable electricity is needed to decarbonise gas demand in Australia.

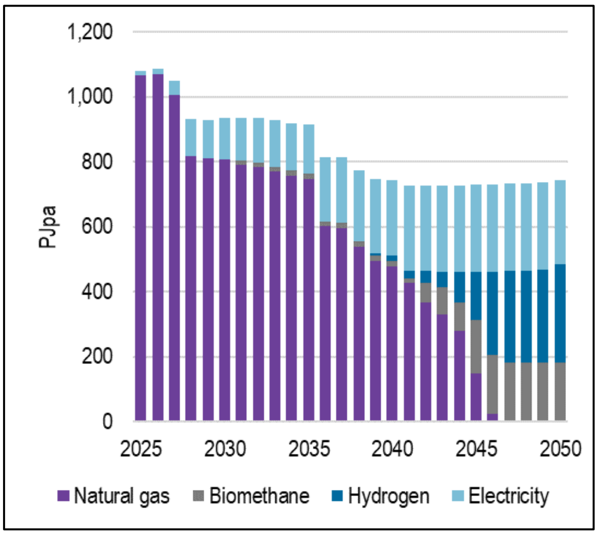
Unsurprisingly, this analysis also confirms that gas use decarbonisation will cost customers and the economy more than maintaining the carbon intensive status quo. Continuing to supply gas customers with natural gas through 2050 will require additional production and appliance replacement investments of around $140bn ($2023) through to 2050. Alternately, electrifying everything possible and supplying renewable gases to remaining gas customers is calculated to cost an additional $60.2bn ($2023), resulting in an average cost of abatement of around $165/tCO²e.

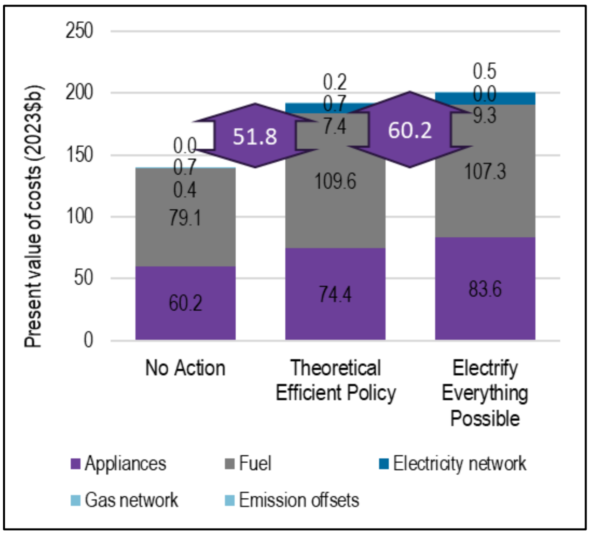
1.2.2 Gas use decarbonisation at lowest total cost

Public sentiment analysis indicates that the majority of Australian energy consumers are sensitive to the costs of decarbonisation[22]. Australian business representatives share this sentiment[23]. While the above EEP scenario requires customers electrify if they can, ACIL Allen also modelled the prospect that renewable gases could be a lower cost option for some customers.

Figure 7 shows the result of the Theoretically Efficient Policy (TEP) scenario, in which decarbonisation was guided by only the cost of energy and appliances and the same net zero carbon budget.

Figure 7: TEP scenario – energy supply breakdown and cost comparison[24]





These two charts show that without the requirement to electrify everything possible, the model selects renewable gas options in many applications. The lowest cost outcome was

[22] RedBridge, 2024, *EnergyShift Australia*, commissioned by APGA, https://apga.org.au/research-and-other-reports/energyshift-australia

[23] Victorian Chamber of Commerce and Industry, 2024, *Gas: a burning issue*, https://www.victorianchamber.com.au/news/gas-a-burning-issue

[24] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, commissioned by APGA and ENA.

delivered using around 480PJpa of renewable gases and 260PJpa of renewable electricity in 2050.

This scenario reduces the additional cost to decarbonise by 14% to $51.8bn ($2023). Important to note is that the ratio of energy and appliance costs differ in this scenario – lower appliance costs in this scenario indicate a lesser burden being put on customers to finance the energy transition through their own, typically higher cost capital.

This outcome accords with the principles of market economics, where providing more options to achieve an outcome often results in lower costs overall. However, the implication is profound for the energy transition. Comparing the EEP and TEP scenarios indicates:

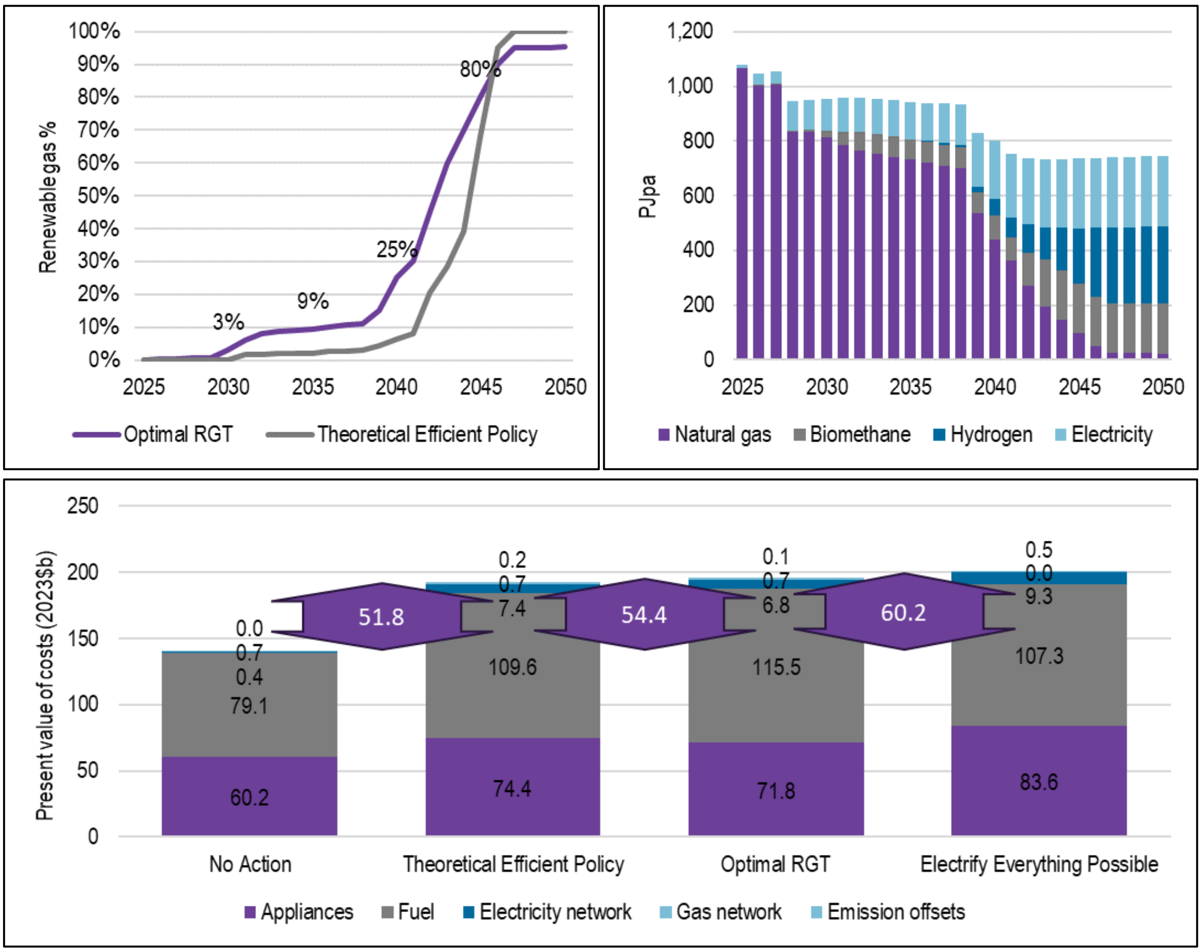
1. Not allowing customers to choose the decarbonisation solution which suits their unique circumstances will increase the cost of the transition.
2. There are gas customers which physically can electrify but could decarbonise through renewable gas purchases for lower cost.
3. Policy supporting renewable gas production is critical to delivering gas use decarbonisation at least cost, rather than at any cost.

1.2.3 Policy to deliver the least cost gas use decarbonisation pathway

While the TEP scenario demonstrates the least cost transition pathway for gas use decarbonisation, it does not represent practical policy solution to implement. Instead, it reflects a pathway achieved through perfect foresight and timing of investments. The TEP is equivalent to introducing a carbon trading scheme with unlimited banking and borrowing.

The Optimal Renewable Gas Target (RGT) was designed to deliver a practically implementable policy and based on past successful Australian energy policy (Figure 8). The intent of this scenario is to set targets of renewable gas as a percent of total gas demand between 2030 and 2050, which marginally brings forward renewable gas production, brings forward cost reduction learnings and flattens development costs in the 2040s.

Figure 8: Optimal RGT – RGT trajectory, energy supply breakdown and cost comparison[25]



The charts in Figure 8 show that by marginally bringing forward renewable gas supply, the Optimal RGT scenario secures gas use decarbonisation in line with the TEP scenario, while marginally increasing costs. Importantly, every gas customer for which it is lower cost to electrify is still able to choose to electrify under the Optimal RGT scenario.

The Optimal RGT scenario is not burdened with the same restrictions that increase cost in the EEP scenario. This scenario maintains the ability for customers to choose which decarbonisation option best suits their unique circumstances, and so reduces the cost of transition. The Optimal RGT scenario also results in lower appliance cost. This means that less of the capital cost burden of the transition falls on consumers.

1.2.4 Importance of economic efficiency when decarbonising gas

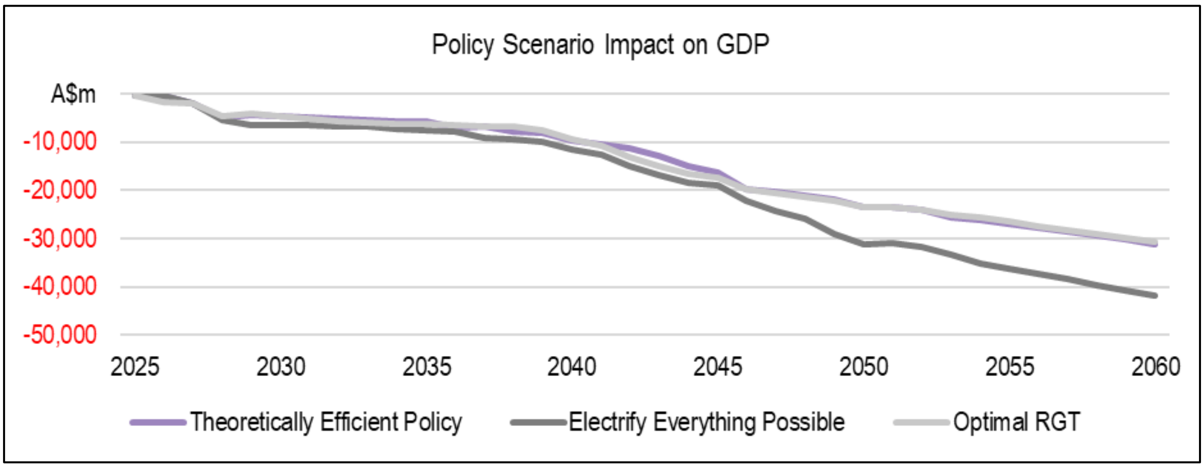
All gas use decarbonisation cases considered in ACIL Allen modelling have a higher resource cost compared to simply continuing to use natural gas. The differences in these higher costs is important when considering the impact of the transition on Gross Domestic Product (GDP).

[25] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, commissioned by APGA and ENA.

When considering gas decarbonisation at a macroeconomic level, the higher cost of the EEP scenario is amplified. Relative to the least cost TEP scenario, the EEP scenario is 11 times more costly to GDP (-$33bn in $2023) than the Optimal RGT scenario (-$3bn in $2023) (Figure 9). This highlights the importance of economically efficient energy policy as any inefficiencies at the microeconomic level are amplified at the macroeconomic level.

Figure 9: Impacts of gas decarbonisation policy choices on GDP

Scenario	Emissions (2025-2060)	Present value of resource cost (2020-2060)	Abatement cost	Change in real economic output (GDP) relative to No Action scenario (2020-2060)	Change in GDP relative to Theoretical Efficient Policy scenario (2020-2060)
	Mt CO_2-e	$b	$/tonne CO_2-e	$b	$b
No Action	1,591	$140			
Theoretical Efficient Policy	724	$192	$143	-$121	$0
Electrify Everything Possible	729	$201	$165	-$154	-$33
Optimal RGT	722	$195	$150	-$124	-$3



1.3 Policy support for gas use decarbonisation

The policy focus areas identified for decarbonising liquid fuels in Section 4.7 of the Discussion Paper can be applied to decarbonising gas supply. Each of the four areas are equally applicable to the renewable gas transition as the renewable liquid fuel transition. Table 3 below maps these policy focus areas to the gas supply chain, including policy actions proposed by APGA.

APGA recommends that the EEPS take the same approach to policy focus areas to enable renewable gases.

Table 3: Renewable gas policy focus areas and associated policy actions

Policy focus areas	1. Decarbonise our gaseous fuel mix	2. Reduce fossil gas demand	3. Ensure gas security and reliability	4. Manage supply chain vulnerabilities
Reason:	Driving renewable gases supports decarbonisation efforts and de-risks gas supply through diversification	Improving energy efficiency and promoting behavioural change reduces emissions and gas demand	Leveraging existing gas security and reliability of supply legislation will ensure climate and energy objectives are met through the transition	Existing mechanisms to address gas supply chain disruptions ensures government and industry can quickly respond to emerging gas supply chain risks
Renewable Gas Policy Action:	- NGER market-based accounting method for gas emissions - A national Renewable gas target in the FGS - Federal contracts for difference for renewable gas	- Increase gas appliance efficiency floor via existing NEPS process [UNDERWAY[26]]	- Expand existing gas security and reliability of supply legislation to cover renewable gases [COMPLETED[27],[28]]	- Expand existing mechanisms to address gas supply chain disruptions to renewable gases [COMPLETED[27,29]]

In some regards, the decarbonisation of gas supply is ahead of liquid fuels. Amendments passed in 2023 extended the National Gas Law (NGL) to renewable gases, extending recent supply security and reliability reforms to renewable gas supply. This ensures that gas security and reliability is maintained and supply chain vulnerabilities are managed. The recently published National Energy Performance Strategy (NEPS) includes consideration of gas appliance efficiency which will support reducing fossil-based gas demand. Decarbonising Australia's gas supply is the logical next step.

[26] DCCEEW, 2024, *National Energy Performance Strategy*, https://www.dcceew.gov.au/energy/strategies-and-frameworks/national-energy-performance-strategy
[27] DCCEEW, 2023, *Extending the national gas regulatory framework to hydrogen and renewable gases*, https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/extending-national-gas-regulatory-framework-hydrogen-and-renewable-gases
[28] AEMO, 2023, *East Coast Gas Reforms*, https://aemo.com.au/en/initiatives/major-programs/east-coast-gas-reforms
[29] Including through the National Gas Emergency Response Advisory Committee; see AEMO, 2024, *National role*, https://www.aemo.com.au/energy-systems/gas/emergency-management/national-role

1.3.1 Policy support to decarbonise our gaseous fuel mix

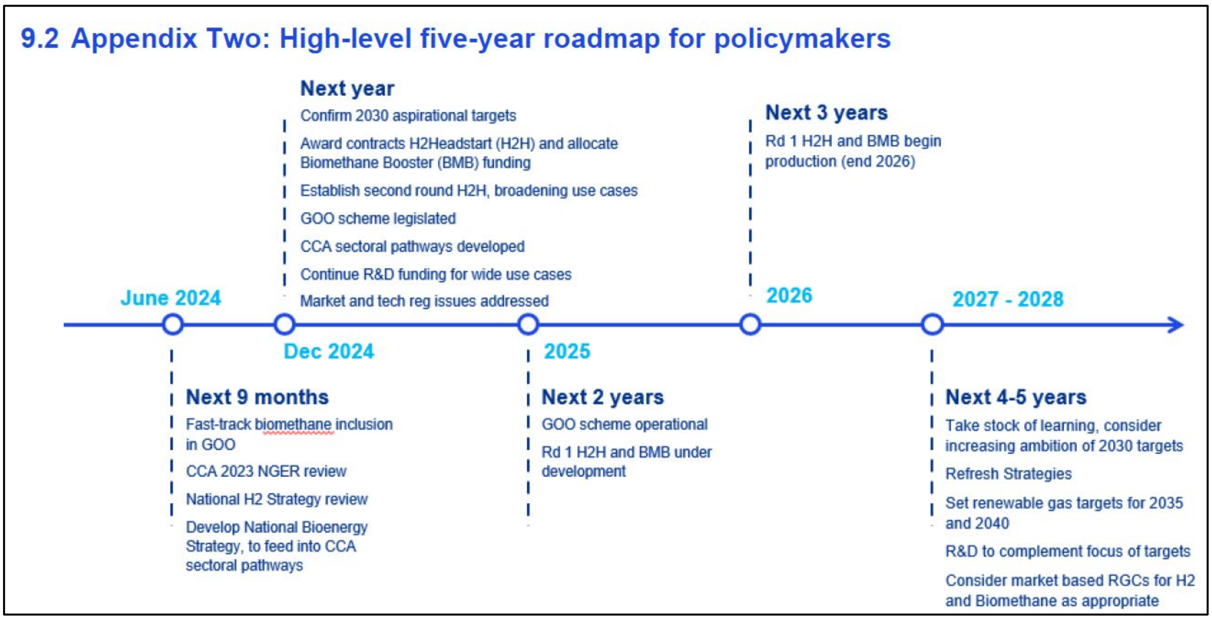
Analysis by KPMG of policy mechanisms supports the economic analysis of ACIL Allen by identifying past successful policy mechanisms which are appropriate to apply to the renewable gas challenge (Figure 10).

APGA identifies three policy mechanisms as being key to enable renewable gas to decarbonise gas use in Australia:

1. Immediate: Enabling renewable gas markets via NGER recognition of renewable gas certificates;
2. Medium term: Sending an investment signal through the introduction of an aspirational national Renewable Gas Target within Australia's emission targets; and
3. Longer term: Avoiding increased energy costs while ensuring targets are met through federally-funded contracts for difference (CfD) schemes targeting renewable gas costs above the cost of natural gas.

At a minimum, APGA recommends the Federal Government undertake modelling to inform its policy development, which considers least cost gas use decarbonisation similar to the ACIL Allen analysis.

Figure 10: KPMG High-level five-year roadmap for policymakers[30]



1.3.1.1 NGER recognition of renewable gas certificates

Renewable gases do cost more than natural gas. To justify paying a higher price, wholesale gas customers must be able to gain additional value beyond energy supply alone when purchasing renewable gas. The additional value which renewable gases can provide is through emissions reduction: the energy is provided at less than 1% of the scope 1

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[30] KPMG, 2023, *Renewable gas: policy options to support Australia's decarbonisation journey*, https://www.energynetworks.com.au/resources/reports/kpmg-report-policy-options-to-support-australias-decarbonisation-journey

emissions of natural gas. For customers to gain access to this value, the NGER Measurement Determination needs to be updated to include a market-based method for accounting for Scope 1 gas emissions.

This is not a new idea. Introduction of a market-based method for Scope 1 gas emissions was recommended by the Climate Change Authority in its December 2023 NGER review report[31]. Such a method already exists for scope 2 emissions accounting for renewable electricity certificates. Renewable gas industry and customers have been requesting this relatively simple policy change for some time – a change which is key to Safeguard Mechanism Facilities being able decarbonise through renewable gas supply.

A market-based method for gas could recognise the surrender of renewable gas certificates issued by Australian state or Federal governments, departments, or agencies. The GreenPower Renewable Gas Certification pilot is already producing Renewable Gas Guarantee of Origin (RGGO) certificates. This scheme could form a basis for design before the Federal Guarantee of Origin (GO) Scheme is finalised, or as an alternative to the GO Scheme.

Design for certificates beyond the GO Scheme is important. Currently, the design of the GO Scheme makes it impossible to integrate with Australia's facilitated gas markets[32]. Additionally, the GO Scheme does not consider biomethane -Australia's lowest cost renewable gas option. The GreenPower scheme does not have these issues.

1.3.1.2 A National Renewable Gas Target (RGT)

It is difficult to see how 2035 targets can be set without understanding the extent to which natural gas use will be decarbonised in the next decade. This makes a renewable gas target an essential input to 2035 economy wide target.

Setting ambitious decarbonisation targets has been a key policy mechanism used by Australian state and Federal governments. While the impact of the Renewable Energy Target (RET) on renewable electricity production makes it Australia's most successful target, more recent schemes indicate the value of simple, aspirational targets in framing renewable energy investment opportunities. As is the case with Australia's 82% by 2030 renewable electricity target, aspirational targets can also leverage government funding to drive public investment – as seen through the Capacity Investment Scheme.

Target Pathway
Through the *Optimal RGT* scenario, ACIL Allen identifies a National RGT pathway that secures a least cost gas use decarbonisation pathway. A National RGT design could be made simple yet agile by setting renewable gas quantity targets every five years, based on a

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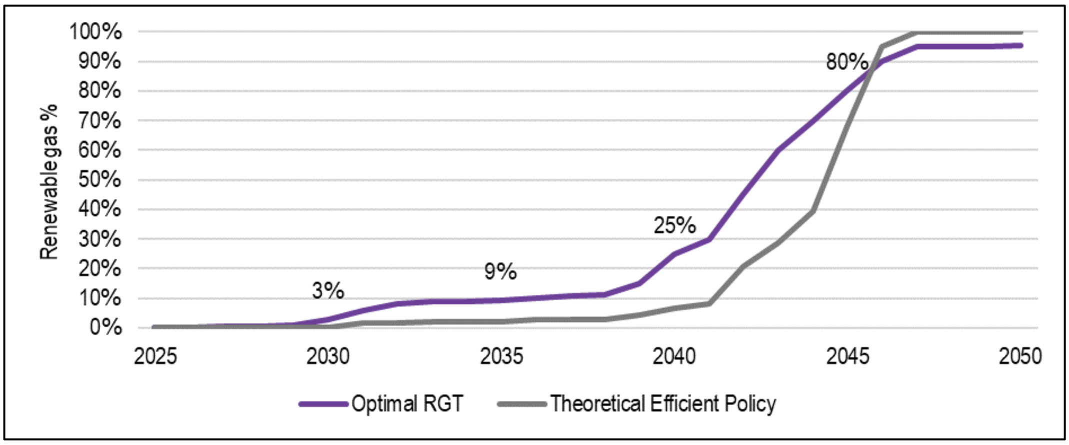
[31] Climate Change Authority, 2023, *2023 Review of the National Greenhouse and Energy Reporting Legislation*, https://www.climatechangeauthority.gov.au/sites/default/files/documents/2023-12/2023%20NGER%20Review%20-%20for%20publication.pdf
[32] APGA, 2023, *Submission: Guarantee of Origin Scheme Accounting*, https://apga.org.au/submissions/guarantee-of-origin-scheme-emissions-accounting; APGA, 2023, *Submission: Guarantee of Origin Scheme Design*, https://apga.org.au/submissions/guarantee-of-origin-scheme-design; APGA, 2023, *Submission: Australia's Guarantee of Origin Scheme*, https://apga.org.au/submissions/australias-guarantee-of-origin-scheme

desired renewable gas percentage of total gas supply (Figure 11). As seen through the RET, regular percentage-based quantity setting ensures that targets remain relevant to Australia's changing energy needs, avoiding over- or under-ambition.

Figure 11: Optimal RGT – Renewable gas target as a percentage of all gas consumption



Value of a National Target over state-based targets
ACIL Allen's renewable gas supply availability and cost findings demonstrate that not all states are equally abundant in renewable gas supply opportunities. However, both the operation of the east coast gas market and ACIL Allen's modelling shows that gases – including renewable gases – can be moved cheaply and efficiently between states. This is in part due to Australia's world class gas transmission pipeline infrastructure which transports gas across the country today.

This indicates that a National RGT can secure lower decarbonisation costs, compared to a state-by-state approach. This is a key reason why ACIL Allen's analyses and the Victorian Government's analyses differ – when only considering renewable gas supply *from* Victoria, the opportunity for renewable gas in Victoria looks much poorer than shown in national modelling.

1.3.1.3 Federally funded contracts for difference

All forms of gas decarbonisation cost more than remaining on natural gas. This must be addressed through the transition as decarbonisation will have cost implications across the economy. It is important that this fact does not prevent the first renewable gas production projects from reaching FID.

Federally-funded CfD, pinned to wholesale natural gas prices, could ensure renewable gas production projects are guaranteed the revenue they need to achieve FID while addressing the cost-of-living concern of potentially higher gas prices. This scheme would be consistent with the intent of the Made in Australia Act and could mirror other such schemes including the Capacity Investment Scheme.

2 Gas enables net zero electricity in Australia

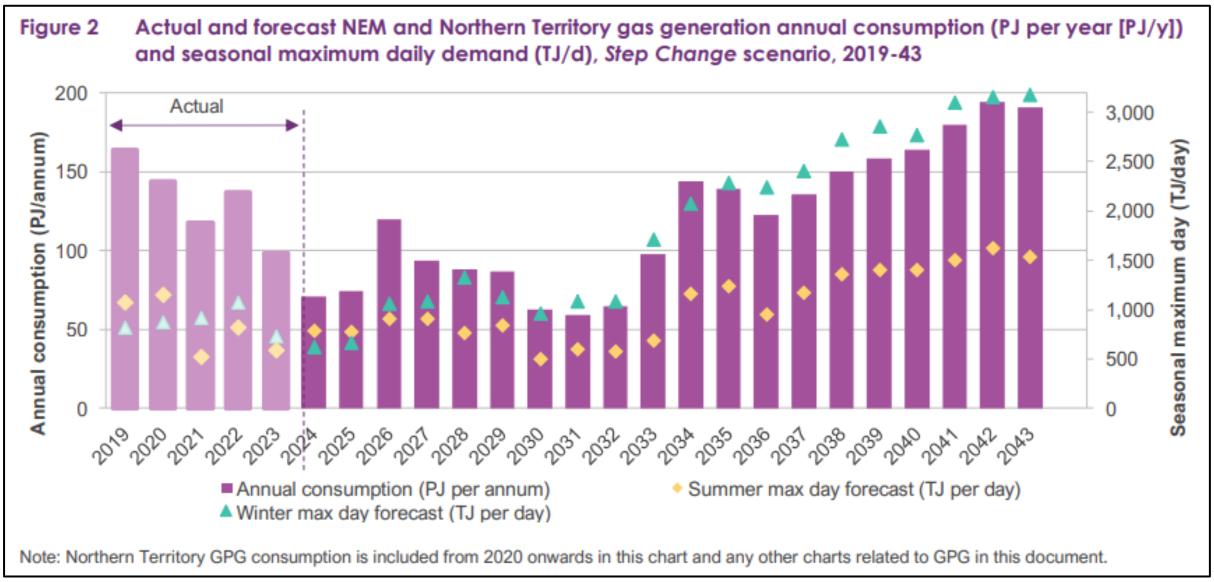
Today's gas supply chain helps keep electricity prices low and reliability and security high. This parallel energy supply chain does so directly by fuelling GPG, and indirectly by reducing electricity system load through supplying large volumes of energy to gas customers.

As Australia transitions towards net zero, a decarbonised gas supply chain can continue to perform this role. It can do so by firming variable renewable generation in a net zero NEM and reducing electricity system demand by supplying energy to those gas customers which need decarbonise via renewable gas for practical or economic reasons.

2.1 GPG helps Australia achieve net zero electricity

There is no doubt about the critical role that GPG plays in achieving net zero electricity in Australia. AEMO analysis shows over 4.4x the GPG capacity used in 2023 is required to supply winter peak demand in the 2040's in line with their net zero consistent Step Change scenario[33] (Figure 12). Analysis by Frontier Economics indicates that a net zero NEM can be achieved at least cost through 93% variable renewable generation and 7% GPG[34]. Frontier Economics also determined that GPG has whole of system cost (WESC) equal to or less than solar in a paper considering the impracticalities of levelised cost analysis in the transition to electricity systems with increasing levels of variable generation[35].

Figure 12: AEMO Gas Statement of Opportunities GPG Forecast



[33] AEMO, 2024, *2024 Gas Statement of Opportunities*, https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf
[34] Frontier Economics, 2021, *Potential for Gas-Powered Generation to support renewables*, commissioned by APGA, https://apga.org.au/research-and-other-reports/potential-for-gas-powered-generation-to-support-renewables
[35] Frontier Economics, 2021, *The role of gas in the transition to net-zero power generation*, commissioned by the Australian Gas Industry Trust and Jemena, https://apga.org.au/research-and-other-reports/the-role-of-gas-in-the-transition-to-net-zero-generation

Public sentiment analysis indicates that the majority of Australian energy consumers are sensitive to the costs of decarbonisation [36]. While it is technically possible to firm the NEM without GPG, it will be necessary to achieving net zero at least cost.

Importantly, GPG doesn't have to remain carbon intensive. Biomethane is 100% compatible with GPG today, and projects including the South Australian Hydrogen Jobs Plan Power Plant Project are on their way to Australian-first demonstrations of 100% renewable GPG. GPG remains a competitive firming option even with renewable gas prices as high as $50/GJ[37].

Without GPG, the NEM falls back on using the next most readily available generation source – coal fired generation. The fact that it is GPG being squeezed out of the NEM while coal generation remains competitive indicates the challenge of achieving lower emissions within the electricity market. Government policy is required to ensuring sufficient competitive GPG is brought online in time for the 2030s in order to avoid more circumstances in which state governments need to underwrite continued coal fired generation that is otherwise ready for retirement[38].

2.1.1 Policy support to ensure GPG investment

Despite this widely recognised and critical role, GPG has been omitted from the Capacity Investment Scheme (CIS). This creates an imbalance in investment incentives against GPG, which puts achieving a net zero NEM at risk. This is because this imbalance in investment incentives risks:

a) Driving investors in existing GPG out of the market; and
b) Deterring potential investors away from investing in the additional GPG the country needs to achieve net zero at least cost.

Including GPG into the CIS would be the simplest way to address this imbalance. Otherwise, a separate targeted scheme is required to ensure the necessary GPG capacity is delivered in time. This scheme could be designed to target delivery of the capacity requirements identified by AEMO's GSOO and/or ISP in the years before they are required.

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[36] RedBridge, 2024, *EnergyShift Australia*, commissioned by APGA, https://apga.org.au/research-and-other-reports/energyshift-australia

[37] Gilmore J, Nelson T, Nolan T, *Firming technologies to reach 100% renewable energy production in Australia's National Electricity Market (NEM)*, https://www.energy.gov.au/sites/default/files/2022-02/Iberdrola%20Australia%20Response%20to%20Capacity%20Mechanism%20Project%20Initiation%20Paper%20-%20Attachment%201.pdf

[38] NSW Office of Energy and Climate Change, 2023, *Electricity Supply and Reliability Check Up: NSW Government Response*, https://www.energy.nsw.gov.au/sites/default/files/2023-09/Electricity_Supply_and_Reliability_CheckUp_NSW_Government_Response_September_2023.pdf; Office of the Premier of Victoria, 2023, *Agreement Secures Transition For Loy Yang A*, https://www.premier.vic.gov.au/agreement-secures-transition-loy-yang

2.2 Decarbonising gas supply takes pressure off a net zero NEM

A big part of achieving net zero electricity and ensuring reliability and security of supply is the scale of uplift required across the coming decades. The scale of change to the Australian electricity system is unprecedented. If there are options to reduce the strain on this system while still achieving a net zero outcome, other important outcomes including energy equity, reliability and security can be more easily achieved.

There is an opportunity for the resilience of a net zero NEM to be optimised by considering:

- Alternative energy infrastructure; and
- Reducing overall demand.

Alternative energy infrastructure

- The NEM is already the longest electricity transmission system in the world. Keeping costs low while maintaining reliability and security of supply, all while increasing variable generation and demand, will be a key challenge of the transition.
- More electricity storage and transmission powerlines will also increase the cost of the NEM, increasing bill costs. Any option to optimise energy infrastructure costs should be taken.
- The hydrogen supply chain can help optimise the electricity supply chain as energy transport and storage using hydrogen pipelines is cheaper than electric alternatives.

Reducing overall demand

- Today, gas and electricity systems share domestic energy demand at a ratio of 20% electricity and 24% gas.
- While many gas customers will electrify, other gas customers will need to stay on the gas system as it decarbonises for practical or economic reasons.
- If continuing to consume energy from a next zero gas supply chain is the right choice for particular gas customers, then this reduces the load – and hence the reliability and security of supply challenge – on a future net zero NEM.

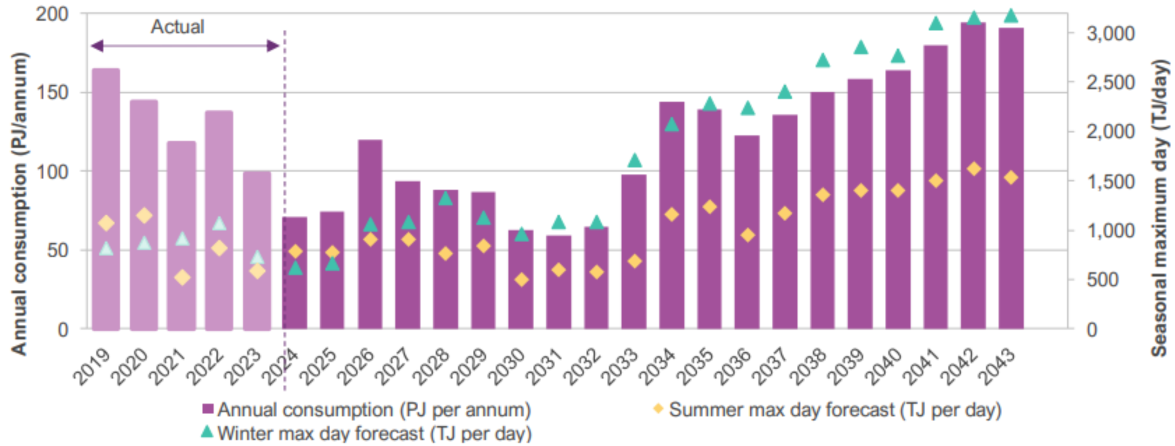
2.2.1 Policy to decarbonise gas supply

The same policy options proposed to decarbonise gas supply will enable a steadily decarbonising gas supply chain to take pressure off a net zero NEM. This demonstrates the value of Australian maintaining parallel and complimentary renewable electricity and renewable gas supply chains in a net zero future. With both supply chains able to firm supply and optimise demand of the other, Australian energy consumers can be the recipients of an optimised net zero energy system able to cater to each consumers unique energy needs.

3 APGA Responses to consultation questions

Consultation question	APGA response
Mobilising investment to transform energy 1. What actions are needed to attract the required large scale private capital and household investment in the energy transformation, with or without government intervention?	<u>Market-based method for Scope 1 emissions of gas combustion accounting under NGER</u> A market-based method is a key immediate action the Australian Government could take to mobilise investment in support of the transition. This would create a commercial proposition for the development of alternative low carbon fuels. • The CCA recommended this action in its 2023 NGER Review report[39]. • A market-based emissions accounting method is needed to create the commercial proposition for purchasing alternative low carbon fuels such as renewable gases. ○ NGER permits recognition of renewable gases in infrastructure, but only where there is a direct connection between a single producer and single customer. • If customers cannot reduce emissions by purchasing renewable gas, then there is no commercial proposition to purchase renewable gas at above natural gas prices. • Without a market-based method, procuring renewable gas supplied via common user infrastructure does not reduce a gas customer's accounted emissions under NGER. • Common user gas infrastructure is the cheapest way to transport and firm wholesale volumes of renewable gas due to low infrastructure cost and economies of scale[40]. • Without a market-based method, state-based renewable gas targets such as the NSW Renewable Fuels Scheme will result in gas customers being levied to subsidise the decarbonisation of others[41]. This is worse for NSW Safeguard Mechanism Facilities which would need to pay for decarbonisation under both the Safeguard Mechanism and the Renewable Fuels Scheme. A market-based method would resolve these conflicts.

[39] Climate Change Authority, 2023, *2023 Review of the National Greenhouse and Energy Reporting Legislation*.
[40] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.
[41] APGA, 2024, *Submission: Renewable Fuels Scheme Rule 1*, https://apga.org.au/submissions/renewable-fuels-scheme-rule-1-consultation; APGA, 2023, *Submission: NSW Renewable Fuels Scheme Expansion*, https://apga.org.au/submissions/nsw-renewable-fuels-scheme-expansion; APGA, 2023, *Submission: NSW Renewable Fuels Scheme*, https://apga.org.au/submissions/nsw-renewable-fuels-scheme

Consultation question	APGA response
	• A market-based method needs a viable certificate scheme – Renewable Gas Certificates being issued today under the GreenPower Renewable Gas Guarantee of Origin program could be used in market-based method design. • Note that current Guarantee of Origin (GO) certificate accounting design makes it impossible to use when supplying hydrogen via existing gas infrastructure[42].
Enabling electrification for a smooth transition 2. What actions are required to ensure Australia's energy systems can enable increased electrification, while maintaining equity, reliability and security?	<u>Enable 82% renewable energy target through Gas Power Generation (GPG)</u> • It is widely recognised that GPG can provide a firming role in an 82% renewable NEM, including AEMO analysis which shows by the 2040s, to supply winter peak demand the NEM will need 4.4x the GPG capacity required during 2023 [43]. **Figure 2 Actual and forecast NEM and Northern Territory gas generation annual consumption (PJ per year [PJ/y]) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2019-43**  Note: Northern Territory GPG consumption is included from 2020 onwards in this chart and any other charts related to GPG in this document.

[42] APGA, 2023, *Submission: Guarantee of Origin Scheme Accounting*; APGA, 2023, *Submission: Guarantee of Origin Scheme Design*; APGA, 2023, *Submission: Australia's Guarantee of Origin Scheme*
[43] AEMO, 2024, *2024 Gas Statement of Opportunities*

Consultation question	APGA response
	• The exclusion of GPG in the Capacity Investment Scheme reduces the incentive for investment in existing or new GPG. • This puts at risk the investment in GPG capacity identified by AEMO as being required to firm the NEM from the mid 2030s onward. • To maintain reliability and security of supply in the NEM, policy support is required to maintain investment in GPG. <u>Maintain grid reliability and security by optimising between powerlines and pipelines</u> • Australian and international analysis concludes that energy transport and storage by pipeline, including hydrogen pipeline, costs less than energy transport by powerline and energy storage via battery energy storage or pumped hydro44. • Gas infrastructure underpins the flexible operation of GPG today, enabling GPG to provide its firming capacity role. Renewable gas infrastructure has the opportunity to provide the same role. • Pipelines also have higher reliability, lower bushfire risk and greater social licence related to electricity transmission powerlines. <u>Maintain equity, reliability and security by enabling customers to choose lower cost options</u> • One of the challenges of maintain equity, reliability and security as Australia electrifies is the scale of the task at hand – more customers electrifying means more money needing to be spent on renewable generation, electricity transmission, electricity storage, and in turn, grid reliability and security mechanisms. • The lowest cost decarbonisation option for some energy customers will be an alternative low emission fuel such as renewable gas or renewable liquid fuel.

[44] Oxford Institute for Energy Studies, 2023, *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/11/ET27-Hydrogen-pipelines-vs.-HVDC-lines_HG_AP_2.pdf; GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.

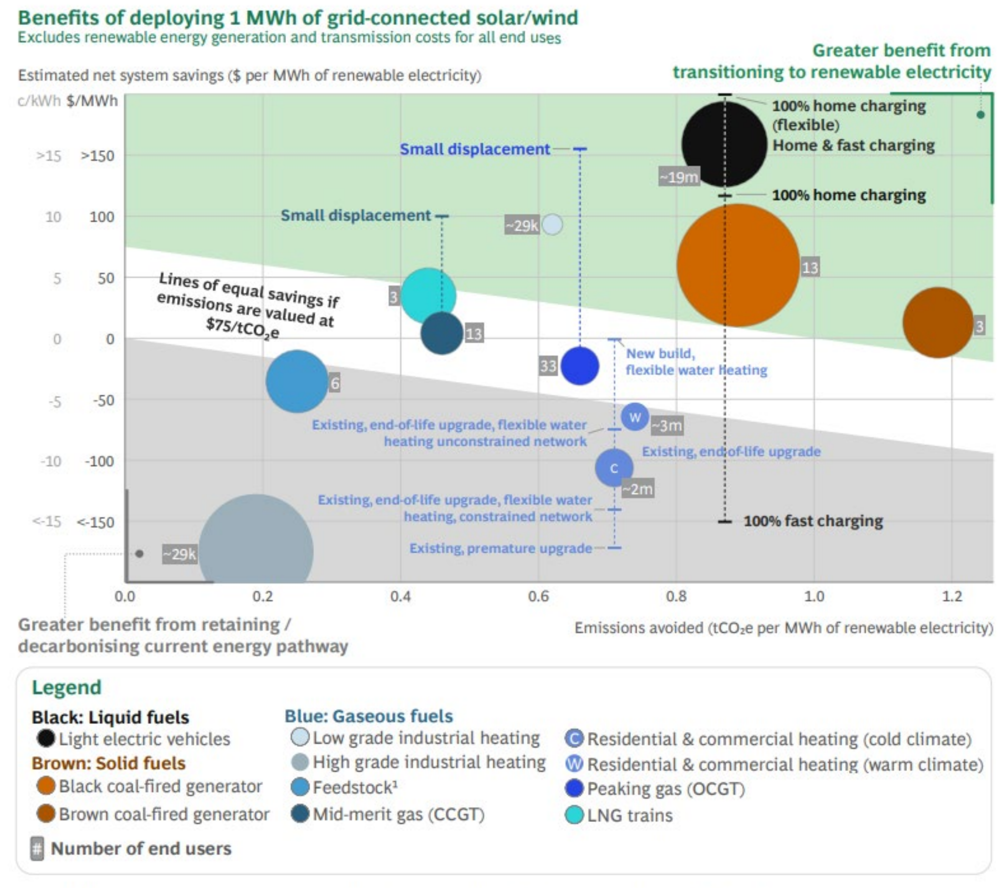
Consultation question	APGA response
	• Creating policy to ensure customers which can decarbonise for lower cost are able to choose their lowest cost option will avoid unnecessary load being placed on the electricity system as it experiences the growing pains of the coming decades. • Customers being able to choose their lowest cost decarbonisation option also supports equity throughout the transition.

<table>
<tr>
<td>3. What insights do you have on the pace, scale and location of electrification, and how to embed this in system planning?

4. How can electrification efforts be sequenced to align with expansion of electricity generation and network capacity?</td>
<td><u>Analysis by Boston Consulting Group (BCG) considers staging of electrification[45]:</u>

• BCG analysis considered the benefits of deploying each MWh of grid-connected solar/wind:

Exhibit 6: Grid-connected renewable electricity will have the greatest impact if first used to displace coal generation and liquid fuels

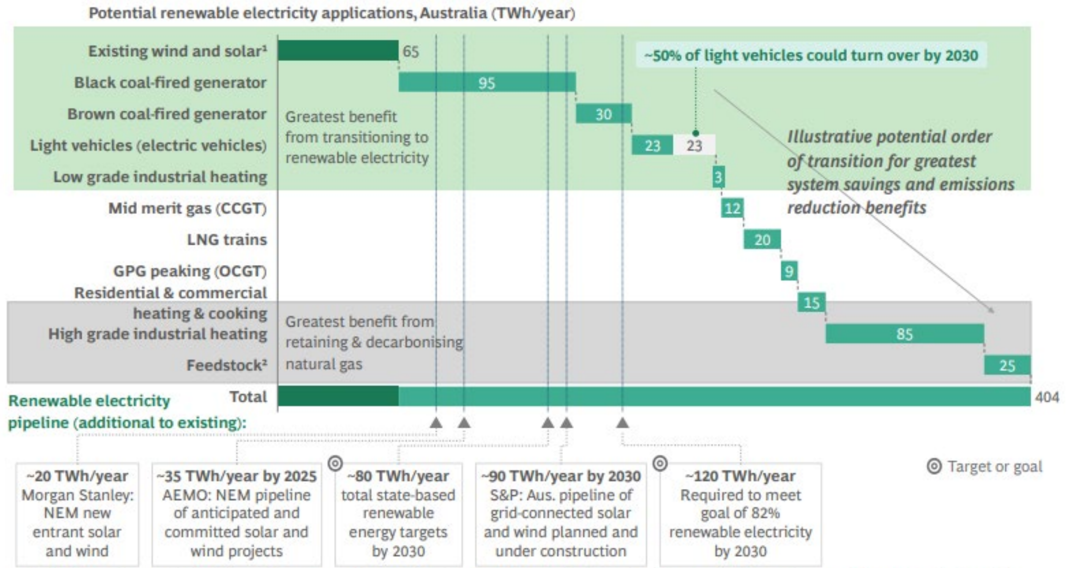


Note: Bubble size represents total annual volume of renewable electricity required to meet demand</td>
</tr>
</table>

- This analysis was then used by BCG to consider end uses which could be prioritised to transition to renewable electricity based on system benefits analysis:

Exhibit 7: In the transition, natural gas can serve critical end uses that are hard and expensive to electrify

End uses could be prioritised to transition to renewable electricity based on system benefits analysis in Exhibit 6

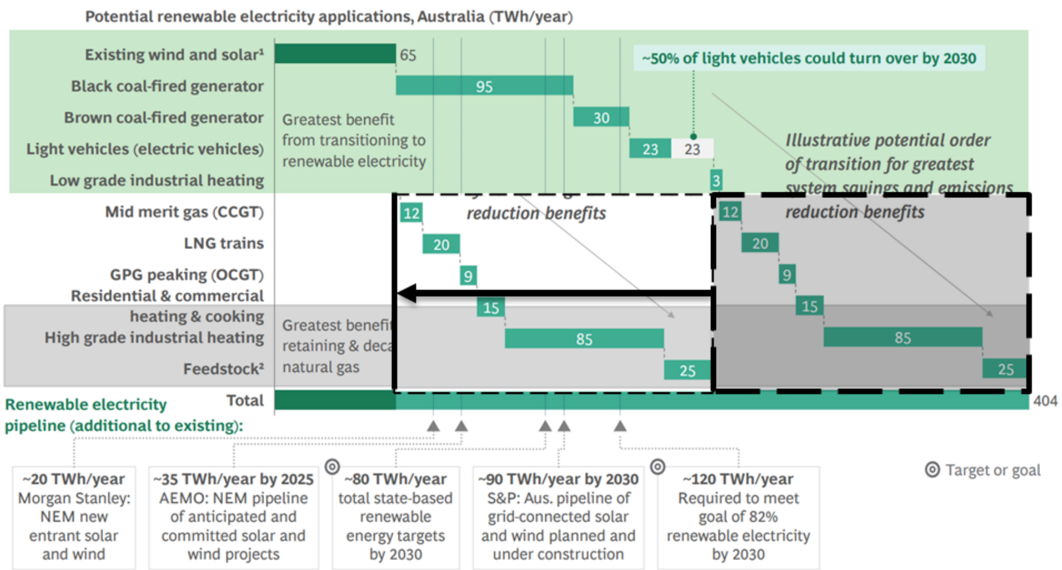


1. Includes onshore wind, utility scale solar, rooftop solar 2. Methane gas substituted with green hydrogen from grid-connected electricity
Source: Morgan Stanley Research, NEM new entrant plant estimate; AEMO, NEM Generation Information (Feb 2023); S&P Capital IQ, World Electric Power Plants Data Base; DCCEEW, Annual Climate Change Statement 2022; BCG analysis

- The energy end uses in the white and grey sections are energy uses which could be decarbonised for equal or lesser cost through renewable gas or liquid fuel uptake.
- This indicates that the energy transition can be accelerated for equal or lesser cost by enabling alternative low carbon fuels such as renewable gas and biomethane.

Exhibit 7: In the transition, natural gas can serve critical end uses that are hard and expensive to electrify

End uses could be prioritised to transition to renewable electricity based on system benefits analysis in Exhibit 6



1. Includes onshore wind, utility scale solar, rooftop solar 2. Methane gas substituted with green hydrogen from grid-connected electricity
Source: Morgan Stanley Research, NEM new entrant plant estimate; AEMO, NEM Generation Information (Feb 2023); S&P Capital IQ, World Electric Power Plants Data Base; DCCEEW, Annual Climate Change Statement 2022; BCG analysis

Consultation question	APGA response
Growing alternative low carbon fuels 3. What policy settings and certainty are required to support a fair, equitable and orderly transition for the decarbonisation of both natural gas and liquid fuels?	<u>An NGER Market-Based Method for gas emissions accounting supports decarbonisation certainty and an orderly transition</u> • Renewable gases cost more than natural gas, but for many current gas customers renewable gases will be the only or the least cost decarbonisation option . • A market-based method is required for gas customers to have the emissions reduction from procuring renewable gas recognised in NGER accounting. • Members of APGA and Bioenergy Australia indicate there are tens of petajoules per annum of identified renewable gas projects which are awaiting a commercial basis upon which to reach FID. • A market-based method creates this basis by connecting emissions reduction to renewable gas procurement. <u>A Renewable Gas Target (RGT) creates certainty and supports a fair and equitable transition</u> • An RGT demonstrates to industry and the Australian public that the Australian government is committed to decarbonising gas supply. • This certainty will reduce investment risk for renewable gas production, allowing for more renewable gas projects to reach FID. • An RGT also provides a purpose for government initiatives in support of renewable gas to target – a government funding aimed at achieving a target is more politically justifiable than a government funding alone. • ACIL Allen analysis indicates that an RGT of 3% by 2030 and 9% by 2035 is sufficient to develop a renewable gas industry in time to achieve net zero gas supply by 2050. <u>Federal renewable gas Contracts for Difference (CfD) supports a fair and equitable transition</u> • A challenge of enabling renewable gases is that they are simultaneously more expensive than natural gas and can be a gas customer’s only or least cost decarbonisation option.

<table>
<tr><th>Consultation question</th><th>APGA response</th></tr>
<tr><td></td><td>Government support in the form of CfD schemes can target CfD values based on ensuring that renewable gases are sold at the same price as natural gas.
Tying government support to a guarantee of no increase in energy prices addresses cost-of-living impact risks while the scheme is in place
A CfD scheme sufficient tied to natural gas price targeting a 3% RGT by 2030 would ensure no cost of living impacts while enabling renewable gas production to develop.</td></tr>
<tr><td>4. What actions are required to establish low carbon fuel industries in Australia, including enabling supply and demand, and what are the most prospective production pathways?</td><td><u>See answers to Questions 1 and 3 above considering policy required to establish renewable gas low carbon fuel industries in Australia.</u>

<u>Biomethane and hydrogen are the most prospective renewable gas production pathways</u>
ACIL Allen analysis shows that a combination of hydrogen and biomethane are used alongside electrification to decarbonise gas use at least cost.
Biomethane represents low hanging fruit being more economically viable than hydrogen in the immediate term, while hydrogen plays a large role in the long term.
If hydrogen or biomethane constraints occur, modelling shows that the alternative renewable gas is the next best alternative. This is shown in modelling by constraining hydrogen or biomethane supply.
The low cost of energy transport and storage via hydrogen pipeline makes electrolysis collocated with renewable energy supply the most prospective hydrogen production pathway[46].
Transporting desalinated water to hydrogen production locations represents negligible increase in hydrogen cost[47].</td></tr>
</table>

[46] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.
[47] Nous Group, 2023, *Net Zero Australia Final Modelling Results*, https://www.netzeroaustralia.net.au/wp-content/uploads/2023/04/Net-Zero-Australia-final-results-launch-event-presentation-19-April-23.pdf

Consultation question	APGA response

5. Are the proposed policy focus areas for managing the liquid fuels transition (outlined in Section 4 of the discussion paper) the correct areas to focus on, and what is missing?	<u>Proposed policy focus areas for managing the liquid fuels transition are equally applicable to managing the gas transition</u>
	• As identified by the EEPS Discussion Paper, Australia needs decarbonised gas supply to achieve net zero as some gas customer have no other decarbonisation alternative.
	• This need sits alongside the need to firm the NEM via GPG and the opportunity for hydrogen to be used in transport decarbonisation.
	• The table below maps these policy focus areas to the gas supply chain including policy actions proposed by APGA to deliver upon each area.
	• In some regards, the decarbonisation of gas supply is ahead of liquid fuels.
	    ○ Amendments passed in 2023 extended the National Gas Law (NGL) to renewable gases, extending recent supply security and reliability reforms to renewable gas supply. This ensures that gas security and reliability is maintained and supply chain vulnerabilities are managed.
	    ○ The recently published National Energy Performance Strategy (NEPS) considers gas appliance efficiency which will support reducing fossil-based gas demand.
	• The remaining policy focus area, decarbonising Australia's gas supply mix, can be supported by the policy options identified under Question 5 above.

<table>
<tr><th>Consultation question</th><th>APGA response</th></tr>
<tr><td></td><td>
<table>
<tr><th>Policy focus areas</th><th>1. Decarbonise our gaseous fuel mix</th><th>2. Reduce fossil-based gas demand</th><th>3. Ensure gas security and reliability</th><th>4. Manage supply chain vulnerabilities</th></tr>
<tr><td>Reason:</td><td>Driving renewable gases supports decarbonisation efforts and de-risks gas supply through diversification</td><td>Improving energy efficiency and promoting behavioural change reduces emissions and gas demand</td><td>Leveraging existing gas security and reliability of supply legislation will ensure climate and energy objectives are met through the transition</td><td>Existing mechanisms to address gas supply chain disruptions ensures government and industry can quickly respond to emerging gas supply chain risks</td></tr>
<tr><td>Renewable Gas Policy Action:</td><td>- NGER recognition of renewable gas certificates
- Setting a national Renewable gas target in the FGS
- Federal contracts for difference for renewable gas supply</td><td>- Increase gas appliance efficiency floor via existing NEPS process [UNDERWAY[48]]</td><td>- Expand existing gas security and reliability of supply legislation to cover renewable gases [COMPLETED[49], [50]]</td><td>- Expand existing mechanisms to address gas supply chain disruptions to renewable gases [COMPLETED[49,51]]</td></tr>
</table>
<u>Policy options to ensure the decarbonisation of gas in Australia is fair, equitable and orderly.</u>
An NGER Market-Based Mechanism ensures fairness by enabling gas customers the ability to account for emissions reduction in line with the renewable gas paid for.
</td></tr>
</table>

48 DCCEEW, 2024, *National Energy Performance Strategy*.
49 DCCEEW, 2023, *Extending the national gas regulatory framework to hydrogen and renewable gases*.
50 AEMO, 2023, *East Coast Gas Reforms*.
51 Including through the National Gas Emergency Response Advisory Committee; see AEMO, 2024, *National role*, https://www.aemo.com.au/energy-systems/gas/emergency-management/national-role

Consultation question	APGA response
	- This includes instances where gas customers are required to pay for renewable gas certificates under legislation such as under the NSW Renewable Fuels Scheme and proposed Victorian and Western Australian renewable gas targets. - A national RGT promotes a fair, equitable and orderly transition. - Fair and equitable transition is enabled by an RGT as it would still allow customers to choose to electrify if this is the best option for the customer. No customer is forced to decarbonise via renewable gas if it is not the best option for their individual circumstances. Less gas customers results in RGT percentages being met more easily by reducing total gas demand. - An RGT promotes an orderly transition by bringing a moderate yet practical portion of renewable gas production forward, ensuring sufficient supply is available in time to be available for customers which required it. This also ensures that cost reducing lessons are learned earlier in the transition. - Government CfDs promote an equitable transition where they are used to keep renewable gas prices low, avoiding cost of living impacts.
Building Australia's clean energy workforce 6. What actions are required to ensure workforce requirements for the energy transformation are met, while supporting equitable outcomes?	<u>Australia's natural gas workforce is ready to deliver renewable gas today</u> - The Australian gas industry boasts a robust skilled workforce skilled in ensuring Australia's gas industry is one of the safest and most successful globally. - The skills to operate natural gas infrastructure are the skills required to operate renewable gas infrastructure. - The rapid development of the Queensland LNG industry demonstrates its ability to mobilise rapidly to deliver upon investment in gas production, transmission and export infrastructure. - Continued lack of government support for renewable gases risks leading to a brain drain on the gas industry – government support of renewable gases should influence more skilled workers staying and moving into the gas industry.

Consultation question	APGA response
Maximising outcomes for people and businesses 7. What actions are required to ensure better energy outcomes for people and businesses, and maximise their benefit from the energy transformation? 8. What social licence and circular economy aspects should be considered as part of the pathway for the energy transformation?	Hydrogen pipelines can derisk energy infrastructure social licence • Not only are gas, biomethane and hydrogen pipelines lower cost than HVAC and HVDC powerlines, but pipelines are inherently underground infrastructure[52]. • This means that there are less visual and practical impacts on landholders once pipelines are installed. • Third party impact and bushfire risks are also lower with buried pipelines compared to aboveground powerlines.
Other 9. What are other gaps in Australia's energy sector decarbonisation policy and what actions are required to address them?	Robust multi- sector energy modelling • ACIL Allen analysis demonstrates the value of modelling the opportunity for multiple energy vectors to decarbonise energy customers. • Modelling robustness including consideration of energy and appliance cost as well as cost ranges can uncover a wider range of cost-effective decarbonisation options. • Without analysis like this, Australia risks making the wrong renewable energy investment decisions, delaying the transition. • APGA recommends that the least cost decarbonisation pathway be modelled each sector of customers considering all physically possible renewable energy alternatives. • APGA understands that the CSIRO is proposing a Smart Energy Mission to pursue multi-sector modelling and recommends that this be prioritised by government.

[52] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context* available at https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/pipelines_vs_powerlines_-_a_technoeconomic_analysis_in_the_australian_context.pdf

Attachment 1: Renewable Gas Target – Delivering lower cost decarbonisation for gas customers and the Australian economy by ACIL Allen

13 December 2023

Submission: Agriculture and Land Sectoral Decarbonisation Plan

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure, connecting natural and renewable gas production to demand centres in cities and other locations across Australia. Offering a wide range of services to gas users, retailers and producers, APGA members ensure the safe and reliable delivery of 28 per cent of the end-use energy consumed in Australia and are at the forefront of Australia's renewable gas industry, helping achieve net-zero as quickly and affordably as possible.

APGA welcomes the opportunity to contribute the Department of Agriculture, Fisheries and Forestry consultation on the first sectoral decarbonisation plan, the Agriculture and Land Sectoral Plan. Australia has the opportunity to reach our national net zero target when all industry sectors work together towards this common goal. However, there is risk of misalignment on electricity and energy decarbonisation between individual sectoral plans.

APGA supports a net zero emission future for Australia by 2050,[1] Renewable gases represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. As set out in Gas Vision 2050,[2] APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC,[3] which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy to homes, businesses, and industry throughout Australia.

Risk of sectoral plan misalignment

The sectoral decarbonisation plans provide the opportunity to develop coordinated decarbonisation strategies for specific industries. In drafting these documents, the relevant departments should aim to address only the issues directly relevant to that industry sector, and in particular leave issues on decarbonising energy and electricity to that sectoral plan.

The consumption of electricity and energy can be decarbonised in two ways:

1. Changing the type of energy being used to a decarbonised or decarbonising type of energy – for example, electrifying diesel demand; or
2. Decarbonising the type of energy already being used – for example, using drop in renewable diesel.

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[1] APGA, *Climate Statement*, available at: https://www.apga.org.au/apga-climate-statement
[2] APGA, 2020, *Gas Vision 2050*, https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[3] Future Fuels CRC: https://www.futurefuelscrc.com/

The five sectoral plans which sit alongside the Electricity and Energy Sectoral Plan risk making uninformed decisions if they make electricity and energy decarbonisation decisions without the context of the Electricity and Energy Sectoral Plan.

Importantly, the Electricity and Energy Sectoral Plan has the opportunity to set all four energy supply chains – solid, liquid, gaseous and electric – on their own decarbonisation journeys. Understanding each of these energy decarbonisation pathways will be key to each other sectoral plan determining the most economically efficient approach to decarbonising their electricity and energy use.

In discussion with DAFF to date, the Agriculture and Land Sectoral Plan appropriately ringfences these issues by only addressing energy and fuel as it pertains to on-farm use. This leaves the conversation of whether existing fuel supply chains could be decarbonised, as well as whether there are multiple alternatives, to the Electricity and Energy sectoral plan. APGA recommends that this model be carried forward for the development of other sectoral plans, and that each plan loops back upon delivery of the Electricity and Energy plan to reconsider its approach to electricity and energy.

Renewable gases can contribute to decarbonisation

The agriculture sector has a unique opportunity to both decarbonise its own sector and provide the necessary feedstock to contribute to the decarbonisation of other sectors. APGA's interest in the Agriculture and Land Sectoral Plan focuses on two areas: increasing feedstocks for use creating biomethane and other renewable biogenic fuels, and on decarbonising on-farm machinery and practices using renewable gases. These areas will be addressed in the following section.

Opportunities for the agriculture sector to decarbonise using renewable gases

The consultation paper acknowledges some of the opportunities available to the agriculture sector to decarbonise using renewable gases.

Decarbonising farming practices

The production of ammonia for use in fertiliser (and other uses) is currently very energy intensive, and is a considerable source of global carbon emissions. Fertilisers produced using renewable gases, rather than fossil gases, offer immediate opportunities to decarbonise farming practices.

Major ammonia producers Incitec Pivot[4] and Yara[5] are transitioning to ammonia production from green hydrogen in Australia. There are also smaller scale, on-farm projects such as the Good Earth Green Hydrogen and Ammonia project[6] on the Keytah cotton station which will support the decarbonisation of the entire property. The project will produce ammonia for use at Keytah and green hydrogen to replace diesel used in regional transport.

[4] Incitec Pivot, 2023, *Green ammonia at Gibson Island*, https://www.incitecpivot.com.au/sustainability/projects/green-ammonia-at-gibson-island
[5] Engie, 2023, *Yuri Renewable Hydrogen to Ammonia Project*, https://engie.com.au/yuri
[6] ARENA, 2023, *Good Earth Green Hydrogen and Ammonia Project*, https://research.csiro.au/hyresource/good-earth-green-hydrogen-and-ammonia-project/

Decarbonising on-farm fuel use
Heavy vehicles and farm machinery are also large contributors to agricultural emissions. Currently, electrification is seen as the major avenue for decarbonising their energy use. Renewable gases should also be supported as a decarbonisation option which is not reliant on potentially challenging electricity or battery infrastructure.

Farm vehicles powered by green hydrogen fuel cells[7,8] and dual fuel technologies[9] are being brought to market and will soon be available in Australia. Biomethane produced from agricultural and other feedstock can also be compressed into a renewable version of CNG, which already powers millions of passenger vehicles worldwide and can be adapted for heavy vehicles and machinery.

Accessing renewable gas supply chains
Both biomethane and green hydrogen supply chains will be readily available for the agriculture industry, provided the right policy settings are in place. As biomethane is chemically indistinguishable from natural gas, existing gas transmission and distribution pipelines can provide access without any changes to the physical infrastructure.

Regional communities will be able to access hydrogen through local generation projects, such as the Good Earth Green Hydrogen and Ammonia projects, or from hydrogen pipelines. Generating renewable electricity, converting it to hydrogen and transporting it in pipelines is a process that may be cost competitive, and certainly much easier, than transporting this energy in transmission powerlines. Gas transmission pipelines are safer, more reliable, and with fewer environmental impacts than transmission powerlines, with fewer impacts on landholders. Ready access to these pipelines will provide opportunities for regional communities to decarbonise which may not be available through transmission powerlines.

Opportunities for the agriculture sector to contribute to broader decarbonisation

The agriculture sector has a unique opportunity both reduce its own emissions and contribute to broader decarbonisation in Australia through the production of biogenic fuels.

Biogenic fuels, including biomethane and bio-CNG, as well as biodiesel, are produced from organic matter and are carbon-neutral when used in place of fossil fuels. Bioenergy Australia's current assessment of biomethane potential in Australia is at least 350 PJ annually, which much of this from the agriculture sector.[10] This can be sourced both from direct production of feedstock, and also from organic agricultural waste. This provides a market for waste product and ultimately a circular economy for agricultural product.

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[7] Seneca ESG, 2023, *Kubota to roll out hydrogen-powered fuel cell tractors in 2025*, https://senecaesg.com/insights/kubota-to-roll-out-hydrogen-powered-fuel-cell-tractors-in-2025/
[8] JCB, 2023, *JCB: Building a hydrogen future*, https://www.jcb.com/en-au/campaigns/hydrogen
[9] Blue Fuel Solutions, 2023, *H_2 Dual Power*, https://h2dualpower.com/en
[10] ENEA Consulting, 2021, *Australia's Bioenergy Roadmap*, https://arena.gov.au/assets/2021/11/australia-bioenergy-roadmap-report.pdf

How this sectoral plan can support decarbonisation

Recommend support for renewable gas supply chains

APGA recommends that the Agricultural and Land Sectoral Plan not make recommendations about electricity and energy, until the recommendations of the Electricity and Energy Sectoral Plan are outlined.

The Agriculture and Land Sectoral Plan should recommend emplacing frameworks for developing renewable gas (specifically biomethane) supply chains. Ideally, this would support a renewable gas target or other mechanism which promotes gas use decarbonisation within the Electricity and Energy Sectoral Plan.

Green hydrogen[11] and biomethane[12] projects are already underway and actively decarbonising gas networks in Australia, supported by state and federal funding. But there are challenges to broader rollout of these technologies, some of which are specific to the agricultural sector. There is currently no widespread deployment of renewable gas, or national plan to achieve this. Ongoing, coordinated, nationally-led policy support for both the supply and demand side is required to provide the necessary signals for investment in the industry.

Whole-of-farm accounting

APGA recommends that the Sectoral Plan consider available carbon accounting methods for agriculture under the Emissions Reduction Fund and whether new or combined methods would be fit for purpose.

Emissions accounting for the agricultural sector is currently piecemeal and not streamlined. This was acknowledged in the *Report of the Expert Panel examining additional sources of low cost abatement*[13] (King Review) as a key limitation to optimising carbon abatement in the agricultural and other sectors. Following the King Review, the Federal Government appointed an independent panel to review the integrity of Australian Carbon Credit Units (ACCUs) under Australia's carbon crediting framework.

Recommendation 5 of the ACCU Review[14] proposes establishing a proponent-led method development pathway. Implementing this recommendation would allow for the development of a method that brings together and expands existing carbon accounting methods under a single "whole-of-farm-accounting" method. The Carbon Market Institute has proposed a

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[11] AGIG, 2023, *Hydrogen Park South Australia*, https://www.agig.com.au/hydrogen-park-south-australia

[12] Jemena, 2023, *Malabar Biomethane Injection Plant*, https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/

[13] Department of Industry, Science, Energy and Resources, 2020, *Report of the Expert Panel examining additional sources of low cost abatement*, https://www.dcceew.gov.au/sites/default/files/documents/expert-panel-report-examining-additional-sources-of-low-cost-abatement.pdf

[14] Department of Climate Change, Energy, the Environment and Water, 2022, Independent Review of Australian Carbon Credit Units Final Report, https://www.dcceew.gov.au/sites/default/files/documents/independent-review-accu-final-report.pdf

model for this, the Active Land Management & Agricultural Production (AL-MAP) method.[15] This method would combine multiple carbon sequestration or emission avoidant land management activities from vegetation and soil which sequester carbon or avoid emissions, under a single method.

The agriculture sector can also be supported through developing a method to recognise natural gas displacement by a wider range of zero emissions gases. Currently this is constrained to biomethane from a narrow range of feedstocks.

To discuss any of the above feedback further, please contact me on +61 422 057 856 or jmccollum@apga.org.au.

Yours sincerely,

JORDAN MCCOLLUM
National Policy Manager
Australian Pipelines and Gas Association

[15] Carbon Market Institute, 2021, *Blueprint for holistic approach to carbon farming – Active Land Management & Agricultural Production (AL-MAP) Method*, https://carbonmarketinstitute.org/app/uploads/2021/08/AL-MAP-Method-Blueprint_final.pdf

ACIL ALLEN

16 February 2024

Report to APGA and ENA

Renewable Gas Target

Delivering lower cost decarbonisation for gas customers and the Australian economy

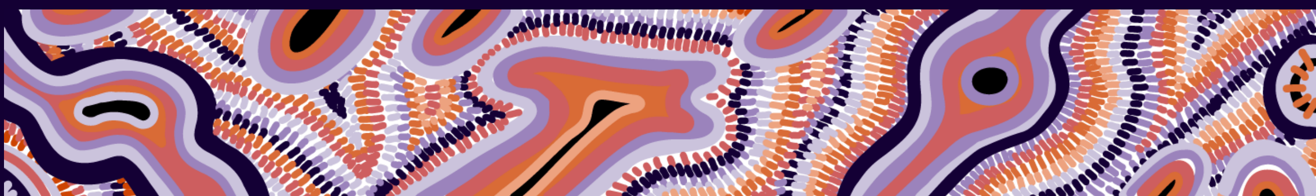
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

Key points

ACIL Allen was engaged by the Australian Pipelines and Gas Association Ltd (APGA) and Energy Networks Australia (ENA) to model the economic effects of a national Renewable Gas Target (RGT). To do this we developed a large-scale linear programming model that identifies the lowest cost way of achieving specified abatement objectives, while continuing to satisfy the underlying energy demand from today's gas using sectors.

Current policies influencing gas customer emissions are insufficient to reach net zero. Our modelling demonstrates that existing gas sector policies are insufficient to achieve net zero emissions for all gas customers – industrial, commercial and residential. It follows that additional policy action is needed to decarbonise this sector.

The most economically efficient pathway to net zero emissions for today's gas users involves a mix of renewable gas and renewable electricity. Theoretical least cost modelling shows that gas customer emissions can be reduced to net zero over the period 2025 to 2050 by switching to a fuel mix of two thirds renewable gases and one third electricity. This decarbonisation costs an average of $143/tonne CO_2-e and reflects possible outcomes under an efficient, broad-based carbon price. However, Australia's complicated history with carbon pricing means that this policy approach is not likely to be politically feasible for the foreseeable future, and so we have modelled other more practical policy options.

A Renewable Gas Target (RGT) could secure net zero gas emissions at a lower cost than a more electrification-focused approach. We modelled an Optimal RGT scenario that achieves the least cost net zero pathway while kick-starting renewable gas supply by 2030, and found that this approach would deliver an average abatement cost of $150/tonne CO_2-e compared to $165/tonne CO_2-e under a more electrification-focused approach (the Electrify Everything Possible scenario). Whole-of-economy modelling found that this saving represents an increase in Australia's gross domestic product in the order of $30 billion (in present value terms) over the transition.

Australia will need access to renewable gas as part of an efficient transition. Sensitivity analysis confirmed the significant role renewable gas is likely to play in decarbonising Australia's gas using sectors. Even when we changed assumptions to favour electrification, multiple hundreds of petajoules of renewable gas is needed, especially for feedstock use and for some very high temperature industrial processes. This result provides a high degree of confidence that policy-makers will need to implement mechanisms to develop renewable gas and ensure it is available for hard-to-electrify sectors in a timely manner. An RGT offers a viable and cost-effective approach to deliver these benefits.

Scenario	Emissions (2025-2060)	Present value of resource cost (2020-2060)	Abatement cost	Change in real economic output (GDP) relative to No Action scenario (2020-2060)	Change in GDP relative to Theoretical Efficient Policy scenario (2020-2060)
	Mt CO_2-e	$b	$/tonne CO_2-e	$b	$b
No Action	1,591	$140			
Theoretical Efficient Policy	724	$192	$143	-$121	$0
Electrify Everything Possible	729	$201	$165	-$154	-$33
Optimal RGT	722	$195	$150	-$124	-$3
Accelerated RGT	714	$202	$164	-$150	-$29

ACIL ALLEN

Contents

Contents

Contents

Contents

Contents

Tables

Contents

Executive summary

ACIL Allen has been engaged by the Australian Pipelines and Gas Association Ltd (APGA) and Energy Networks Australia (ENA) to model the economic effects of a national Renewable Gas Target (RGT).

Overview

Policy action is needed to decarbonise Australia's natural gas sector. In the absence of policy action, today's gas customers are projected to overwhelmingly stay on natural gas, and emissions from these users will continue to increase, producing over 1.5 Gt CO_2-e over the period 2025 to 2050. We estimate that a net zero-consistent gas sector emissions budget would be less than half of this volume of emissions, illustrating the significant abatement task facing the sector

Efficient emissions reduction is best achieved through a broad-based and technologically-neutral policy that provides equally strong incentives across all emissions sources and abatement actions. ACIL Allen has modelled a Theoretical Efficient Policy scenario that decarbonises the gas industry in line with achieving net zero by 2050 as might occur under a theoretically optimal policy such as a broad-based carbon price. Under this scenario gas customer emissions are reduced to net zero over the period 2025 to 2050, achieving cumulative abatement of 867 Mt CO_2-e at an average abatement cost of $143/tonne CO_2-e. Renewable gas contributes about two-thirds of the long-term energy needs of today's gas users, with electricity providing the remaining third.

However, Australia's complicated history with carbon pricing means that implementing an optimal policy approach consistent with the Theoretical Efficient Policy scenario is not likely to be politically feasible for the foreseeable future. Instead, other more practical policy approaches are needed to decarbonise the gas sector. The policy action required goes beyond existing gas sector emissions policies– such as the national Safeguard Mechanism for large gas users, and the Victorian and ACT bans on new residential gas connections – which are insufficient to reach net zero by 2050.

We have modelled alternate policy frameworks for a net zero consistent pathway for the gas sector, including an electrification-focused approach and a Renewable Gas Target (RGT) that supports the progressive replacement of natural gas with renewable gases, principally green hydrogen and biomethane (Box ES 1).

Our modelling shows that an RGT can reduce emissions to net zero by 2050 at a lower cost of abatement than an electrification-focused approach ($150/tonne CO_2-e under the Optimal RGT scenario compared to $165/tonne CO_2-e under the Electrify Everything Possible scenario).

When translated to the whole economy, adopting an RGT rather than an electrification-focused approach to decarbonisation of the gas sector will increase Australia's gross domestic product in the order of $30 billion (in present value terms) over the transition.

Box ES 1 What is renewable gas

Renewable gases are gaseous fuels that can largely or entirely substitute for existing uses of natural gas in today's energy system. This analysis focuses on two main types of renewable gas: biomethane (where biogas is produced through anaerobic digestion of biomass and purified to become primarily methane) and green hydrogen (hydrogen produced from electrolysis using renewable electricity).

This analysis does not consider hydrogen produced from natural gas or coal, or naturally-occuring hydrogen.

Even when decarbonisation is accelerated as under the Accelerated RGT scenario, costs are marginally lower per unit than an electrification-focused approach ($162/tonne CO_2-e, compared to $165/tonne CO_2-e).

Scenario	Emissions (2025-2060)	Present value of resource cost (2025-2060)	Abatement cost	Change in real economic output (GDP) relative to No Action (2025-2060)	Change in GDP relative to Theoretical Efficient Policy (2025-2060)
	Mt CO_2-e	$b	$/tonne CO_2-e	$b	$b
No Action	1,591	$140			
Theoretical Efficient Policy	724	$192	$143	-$121	$0
Electrify Everything Possible	729	$201	$165	-$154	-$33
Optimal RGT	722	$195	$150	-$124	-$3
Accelerated RGT	714	$202	$164	-$150	-$29

Under all scenarios, Australia will need access to renewable gas as part of an efficient transition. Even under an electrification-focused approach, renewable gas is needed for feedstock use and for some very high temperature industrial processes. Policy support is needed to develop these energy options and ensure they are available for hard-to-electrify sectors in a timely manner. Developing renewable gas will also reduce the risk of relying too heavily on electrification to decarbonise the gas sector. The transition within the electricity industry is already showing signs of slippage and cost escalation, and additional incremental demand from electrification of gas loads will only add to these pressures and make achieving renewable energy targets in electricity more difficult.

Policy-makers should support an RGT to develop a broader range of technology options and support today's gas users to choose the best option for them as cost trends become clear. This flexible approach will avoid locking in poor choices based on early trends or assumptions.

In the RGT scenarios, the modelling imposes a trajectory for renewable gas in the form of a constraint on the minimum amount of renewable gas development and consumption. It does not however model the specifics of a policy mechanism required to bring this about. Such a mechanism could take several forms including:

— a certificate-based market mechanism (arguably the most efficient) similar in nature to the Renewable Energy Target for electricity

— a direct contracting type scheme similar to the recently announced Capacity Investment Scheme or Hydrogen Headstart Program.

Irrespective of the policy mechanism to be employed, some form of policy support is likely to be needed to create the necessary investment environment for renewable gas.

Modelling the transition of gas customers to net zero

To analyse the effects of an RGT we developed a Gas Transition Model (GTM) to provide insights into potential cost pathways to decarbonise Australia's existing gas using sectors. The model uses a large-scale linear program to identify the lowest cost way of achieving specified abatement objectives, while continuing to satisfy the underlying energy demand from today's gas using sectors.

We have used the GTM to model five core scenarios:

— A **No Action scenario** in which no emissions constraint applies to the sector. This scenario is utilised solely to calculate the relative cost of abatement for the other scenarios.

— A **Theoretical Efficient Policy scenario** which imposes a gas sector emissions constraint consistent with a national pathway to net zero emissions by 2050 and allows the model to identify the lowest cost way to achieve this outcome.

— An **Electrify Everything Possible scenario**, which assumes an overall emissions constraint consistent with a national pathway to net zero emissions by 2050, but restricts uptake of renewable gas options other than for activities where electrification is not possible or proven (such as feedstock and some very high temperature processes.

— An **Optimal RGT scenario**, which translates the outcomes of the Theoretical Efficient Policy scenario into a set of renewable gas targets that the model must achieve. This scenario effectively translates the generalised emissions reduction constraint from the Theoretical Efficient Policy scenario into a specific policy mechanism that can be implemented in practice. In this scenario we also slightly accelerate the uptake of renewable gas, to reflect a more gradual and realistic ramp-up of renewable gas industry capacity.

— An **Accelerated RGT scenario**, which includes an accelerated ramp-up of the renewable gas industry to more rapidly decarbonise the stationary energy sector and de-risk the development of the renewable gas sector. This accelerated adoption of renewable gas could be desirable if policy-makers wish to reduce the risk that renewable gas adoption will be hampered by logistical constraints, recognise the potential for renewable gases to underpin emerging export industries such as green hydrogen, green ammonia or green iron, or seek to hedge against potential difficulties in achieving abatement in other sectors of the economy.

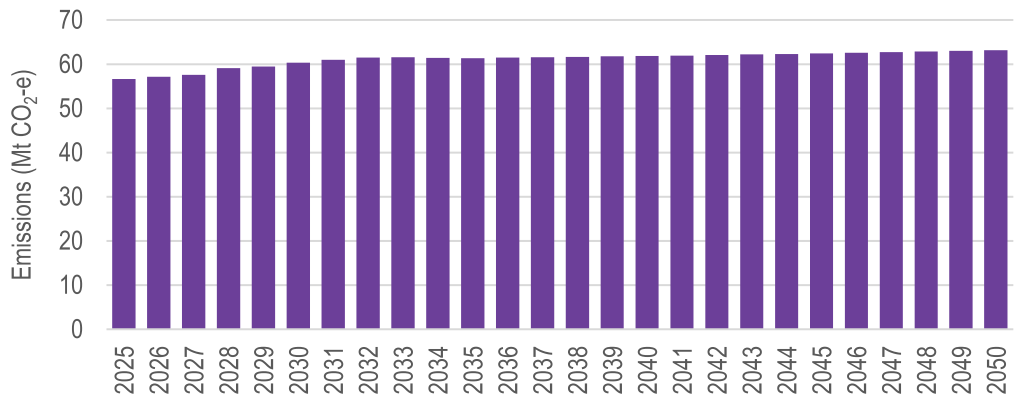
The GTM uses a range of assumptions including wholesale energy costs for electricity, natural gas, hydrogen and biomethane, and appliance capital cost, efficiency and operating life assumptions across a range of customer classes. As with any such long-term projections, there is a degree of uncertainty and the modelled results reflect the particular set of assumptions as detailed in the report. Given this uncertainty, both higher and lower cost outcomes are possible for each key variable, and different assumptions may deliver larger or smaller roles for renewable gas in the gas sector transition.

Key outcomes

Policy is needed to decarbonise the gas sector

The No Action scenario demonstrates that policy action is needed to decarbonise the sector. In the absence of policy action, today's gas customers overwhelmingly stay on natural gas, and emissions from these users continues to increase (Figure ES 1), albeit slowly, producing over 1.5 Gt CO_2-e over the period 2025 to 2050 inclusive. This cumulative volume of emissions is more than double the volume of the gas sector emissions budget we model as being consistent with achieving net zero emissions by 2050.

Figure ES 1 No Action scenario emissions (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

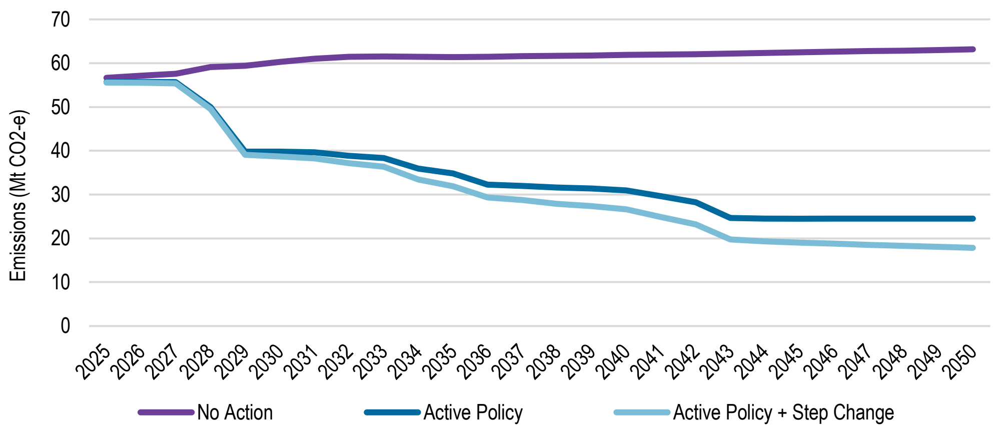
To further understand likely emissions outcomes under current policy, we also modelled sensitivities to capture the effect of current and potential policies:

— an Active Policy sensitivity that includes the effects of the national Safeguard Mechanism for large gas users, and the Victorian and ACT bans on new residential gas connections

— an Active Policy + Step Change sensitivity that incorporates the policies above as well as further residential and commercial sector electrification, consistent with the levels assumed under AEMO's Step Change scenario in the 2023 Gas Statement of Opportunities.

While emissions do reduce under these sensitivities, the modelled policies are not sufficient to achieve net zero by 2050. The Active Policy sensitivity results in emissions leveling off at around 24 Mt CO_2-e per year, while under the Active Policy + Step Change sensitivity annual emissions reduce to around 18 Mt CO_2-e over the same timeframe.

Figure ES 2 Emissions: Active Policy and Active Policy + Step Change sensitivities vs No Action scenario (Mt CO_2-e)

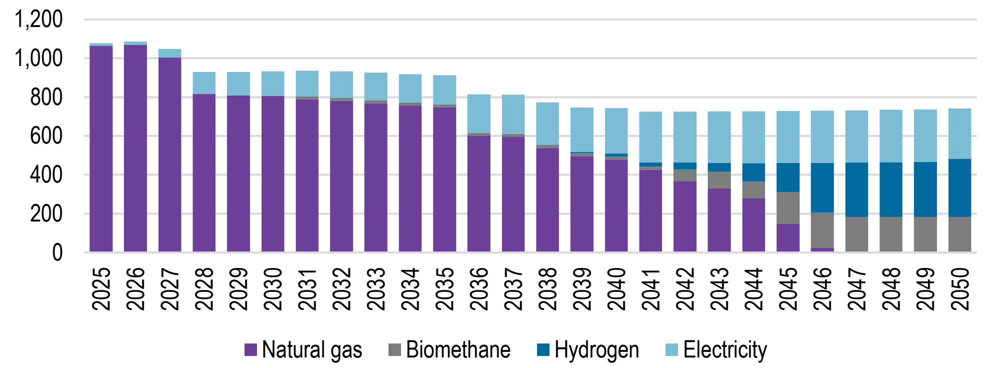


Source: ACIL Allen Gas Transition Model

Renewable gases play a key long-term role in decarbonising gas using sectors

The Theoretical Efficient Policy scenario projects a significant role for renewable gases in decarbonising Australia's gas-using sectors. While most of the early decarbonisation chosen by the model is through electrification, such as electrifying liquefaction compressors in the LNG industry, renewable gases play a larger overall role in serving the long-term energy needs of existing gas users. Approximately two-thirds of the long-run energy needs of today's gas-using sectors are met using renewable gases, and the remaining third is met with electricity (Figure ES 3).

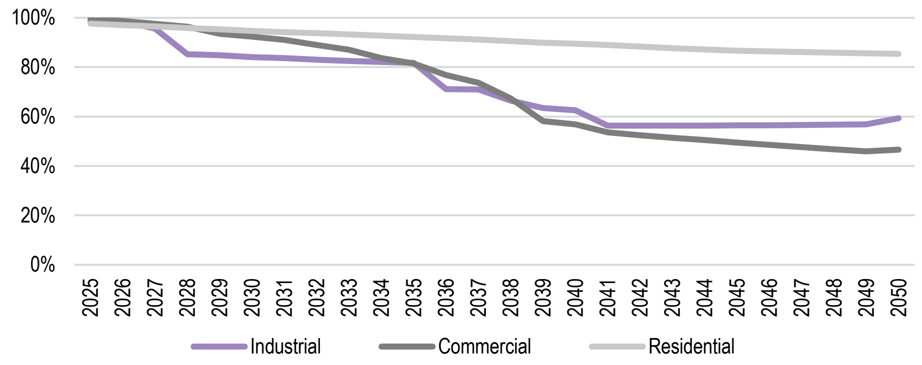
Figure ES 3 Theoretical Efficient Policy scenario fuel mix (PJ)



Source: ACIL Allen Gas Transition Model

Gaseous fuels and electricity both play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector (Figure ES 4).

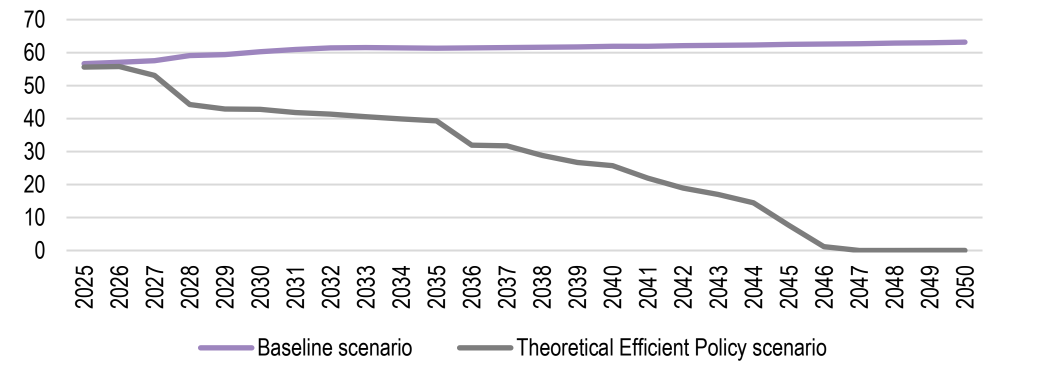
Figure ES 4 Theoretical Efficient Policy scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

The combined effect of electrification and investment into renewable gases rapidly reduces emissions from the gas sector, consistent with Australia's net zero objective (Figure ES 5).

Figure ES 5 Emissions: Theoretical Efficient Policy scenario relative to No Action scenario (Mt CO_2-e)

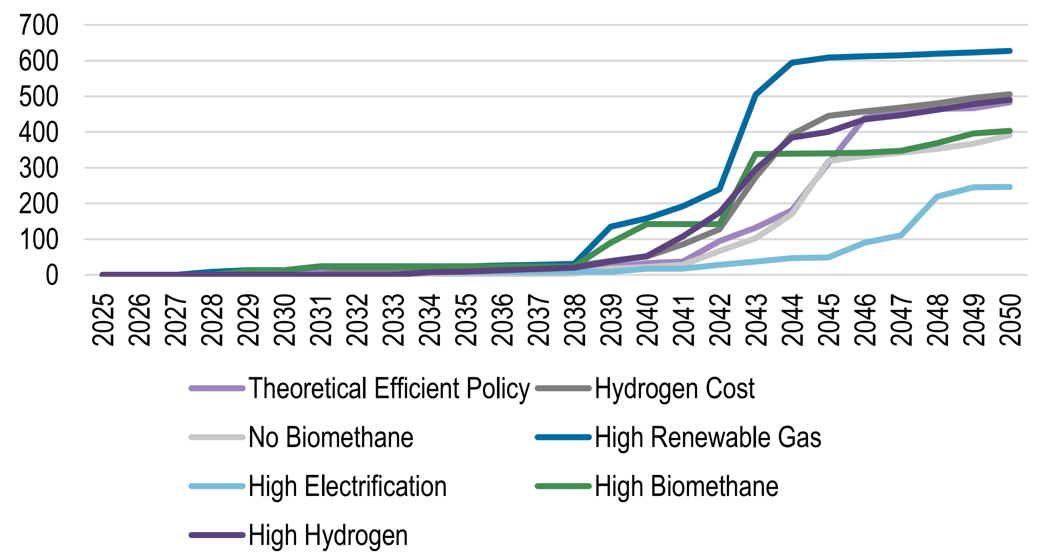


Source: ACIL Allen Gas Transition Model

The important role of renewable gas in decarbonising Australia's gas using sectors was confirmed through sensitivity analysis which varied cost assumptions from those in the Theoretical Efficient Policy scenario. This tests outcomes if technology cost trends vary from those assumed in the core modelling.

Figure ES 6 shows the level of renewable gas production under the Theoretical Efficient Policy scenario and sensitivities. This analysis shows that about 250 PJ of renewable gas is needed by 2050 if cost trends move favourably for electrification (the High Electrification sensitivity), while all other sensitivities involve significantly more renewable gas development. While the variation in results show that the precise timing and scale of renewable gas development is uncertain, policy-makers can still have a high degree of confidence that policies will be needed to support the development of a sizable renewable gas industry capable of supplying multiple hundreds of petajoules by 2050.

Figure ES 6 Renewable gas volumes (PJ): Theoretical Efficient Policy scenario compared to sensitivities



Source: ACIL Allen Gas Transition Model

While this scenario represents a decarbonisation pathway that might occur under a theoretically perfectly efficient policy such as a broad-based carbon price, and highlights that both renewable gas and electrification contribute to decarbonising today's natural gas users, Australia's complicated history with carbon pricing means that implementing policy consistent with this scenario is not likely to be politically feasible for the foreseeable future. Therefore we also examined additional scenarios that explore practical policy approaches to decarbonise the sector.

A balanced approach involving both renewable gas and electrification reduces cost

To compare the costs and benefits of potential practical policy approaches, we compared three further policy scenarios (described above):

— an Electrify Everything Possible scenario

— an Optimal RGT scenario

— an Accelerated RGT scenario.

The modelling demonstrated that restricting use of renewable gas and favouring electrification under the Electrify Everything Possible scenario increases the overall cost of the transition, relative to the use of a renewable gas target under the Optimal RGT scenario (Figure ES 7). Reflecting the lower overall cost, the Optimal RGT scenario achieves emissions at a lower per unit cost: \$150/tonne CO_2-e on average instead of \$165/tonne CO_2-e under the Electrify Everything Possible scenario.

An electrification-focused policy approach also changes the type of costs incurred during the transition. Compared to the theoretically efficient policy approach or an RGT-based approach, an electrification-focused approach requires customers to spend more capital upfront on changing appliances, in return for lower operating costs. While this is not significant within the modelling, where users do not face barriers in raising capital to change appliances, in practice some users may find it difficult to raise the capital in a timely fashion to electrify, creating an additional level of risk to the transition relative to more balanced approaches that use more renewable gas.

An important benefit of an RGT relative to an electrification-focused policy approach is that an RGT supports customers to choose either renewable gas or electrification depending on their particular circumstances. By requiring gas customers to consider the relative costs of using electricity and decarbonised gaseous fuels, an RGT creates an incentive for customers to electrify where the economics of this are suitable, while creating incentives for customers to purchase decarbonised gases when electrification is not suitable.

While the Optimal RGT scenario has slightly higher abatement cost than the Theoretical Efficient Policy scenario, it represents a practically achievable path to developing the renewable gas industry to support the decarbonisation of today's gas users. The Optimal RGT scenario brings forward renewable gas development relative to the theoretically optimal path identified in the Theoretical Efficient Policy scenario, which would have a number of real world benefits that are not captured within an optimisation modelling framework that predicts outcomes with perfect foresight. For example, bringing forward renewable gas development can:

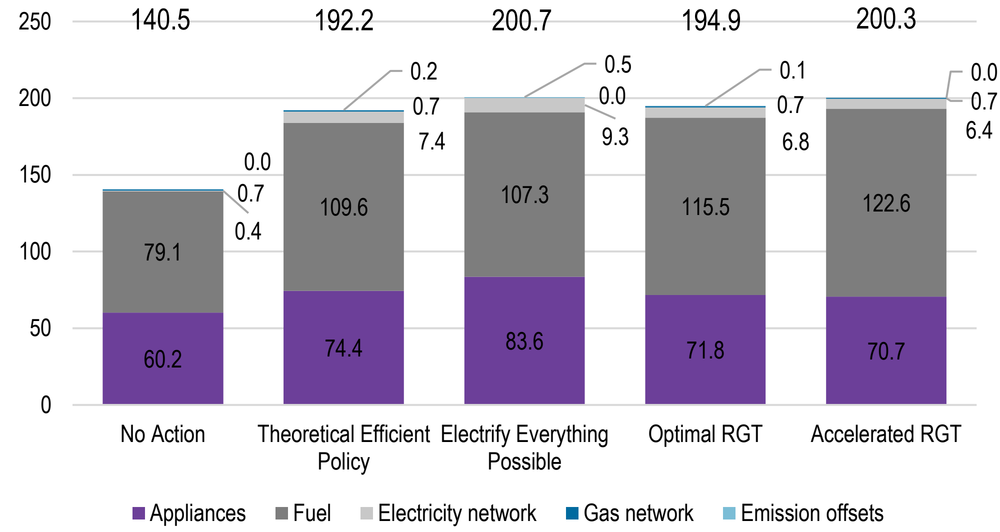
— develop industry capability and skills more gradually, rather than relying on a potentially unrealistically rapid ramp up in investment and production as is modelled in the Theoretical Efficient Policy scenario

— reduce the risk that projects will be delayed or supply chain constraints may not support extremely rapid ramping of production (as has been seen, for example, in ramping renewable electricity generation capacity in recent years).

— build confidence of gas users to choose renewable gas by demonstrating its technical feasibility and real-world economics of renewable gas will be important to, which in turn may allow users to wait for this technology to be deployed at scale rather than rushing to solutions that are more mature today, but which may prove higher cost in the long-run.

Even when decarbonisation is accelerated as under the Accelerated RGT scenario, the cost off abatement is lower than under the Electrify Everything Possible scenario ($162/tonne CO_2-e, compared to $165/tonne CO_2-e).

Figure ES 7 Present value of costs by category, 2025 to 2060: by scenario (real 2023$b)



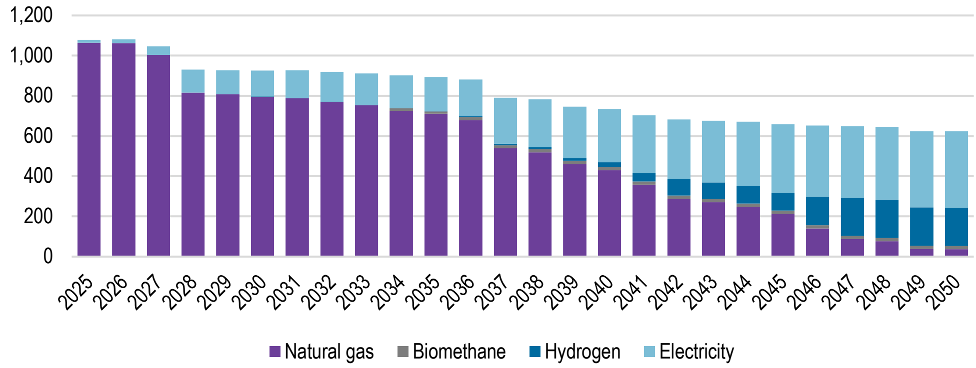
Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

Together these results highlight that failing to develop renewable gases significantly risks the energy transition. If Australia's policy framework does not sufficiently support the development of a renewable gas industry, many gas users will face higher costs and a more uncertain transition. Policy-makers should not seek to decarbonise with a 'one-size-fits-all' approach but should seek to develop both renewable gas and electrification options and allow consumers to choose the most suitable ways to decarbonise given their particular circumstances and preferences. Translating the model results to reflect the uncertainty present in the real-world through the energy transition, the modelling results will be sensitive to assumptions and the fuel and technology cost trends assumed here may not play out in practice. Given that uncertainty, keeping more technology options on the table will reduce risk in the transition – for example if one technology pathway proves more expensive or difficult than anticipated, users can adopt a different pathway.

Even under the Electrify Everything Possible scenario, the technical difficulty of electrifying some sectors results in a meaningful role for renewable gas (Figure ES 8). This indicates that policy-makers must develop a framework to develop this option to serve the needs of energy users, as many users need access to renewable gas in a net zero emissions future.

Figure ES 8 Electrify Everything Possible scenario fuel mix (PJ)



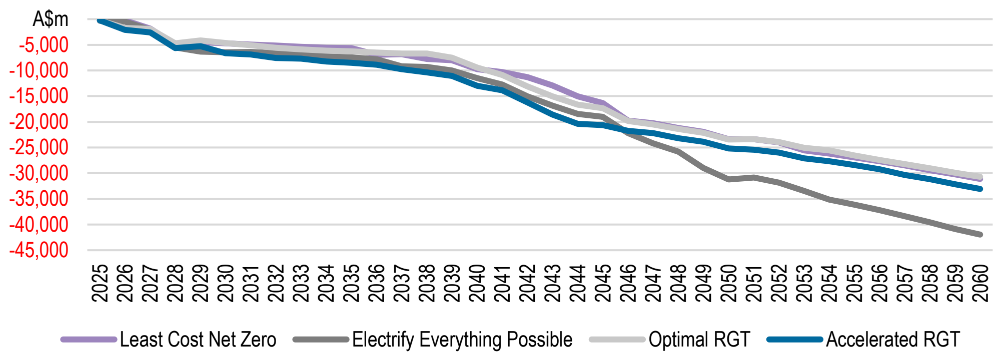
Source: ACIL Allen Gas Transition Model

Broader economic impacts

Undertaking a large-scale transition of the Australian energy system will result in a range of macroeconomic impacts beyond those analysed in the gas sector alone. Some of these will be positive (such as reductions in expenditure resulting in improving the competitiveness of Australian businesses or reducing the cost of living for residents), while some will be negative (such as increased expenditure reducing the competitiveness of Australian businesses or increasing the cost of living for residents).

There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, energy prices and volumes, and efficiency changes (Figure ES 9).

Figure ES 9 Annual change in gross domestic product under each scenario relative to the No Action scenario (real 2023$m)



Source: ACIL Allen Tasman Global modelling

In total, over the period to 2060 the present value of the reduction in Australia's GDP relative to the No Action scenario (using a 7% discount rate) is:

— –$121.1 billion under the Theoretical Efficient Policy scenario
— –$154.5 billion under the Electrify Everything Possible scenario
— –$124.2 billion under the Optimal RGT Scenario
— –$150.0 billion under the Accelerated RGT Scenario.

These results indicate that, translated to the whole economy, adopting an Optimal RGT rather than an electrification-focused approach to decarbonisation of the gas sector will save Australia in the order of $30 billion (in present value terms) over the transition.

Introduction 1

ACIL Allen has been engaged by the Australian Pipelines and Gas Association Ltd (APGA) and Energy Networks Australia (ENA) to model the economic effects of a national Renewable Gas Target (RGT).

An RGT is a policy to support the progressive replacement of natural gas with renewable gases, principally green hydrogen and biomethane. It would work in a similar way to the national Renewable Energy Target (RET) which supports investment in renewable electricity generation, and so an RGT would support investment in the renewable gas industry and allow it to mature and support the decarbonisation of Australian gas users.

To analyse the effects of an RGT we developed a Gas Transition Model (GTM) to provide insights into potential cost pathways to decarbonise Australia's existing gas using sectors. The model uses a large-scale linear program to identify the lowest cost way of achieving specified abatement objectives, while continuing to satisfy the underlying energy demand from today's gas using sectors.

We have used the GTM to model five core scenarios:

— A **No Action scenario** in which no emissions constraint applies to the sector.

— A **Theoretical Efficient Policy scenario** which imposes a gas sector emissions constraint consistent with a national pathway to net zero emissions by 2050 and allows the model to identify the lowest cost way to achieve this outcome.

— An **Electrify Everything Possible scenario**, which assumes an overall emissions constraint consistent with a national pathway to net zero emissions by 2050, but restricts uptake of renewable gas options other than for activities where electrification is not possible or proven (such as feedstock and some very high temperature processes).

— An **Optimal RGT scenario**, which translates the outcomes of the Theoretical Efficient Policy scenario into a set of renewable gas targets that the model must achieve. This scenario effectively translates the generalised emissions reduction constraint from the Theoretical Efficient Policy scenario into a specific policy mechanism that can be implemented in practice. In this scenario we also slightly accelerate the uptake of renewable gas, to reflect a more gradual and realistic ramp-up of renewable gas industry capacity.

— An **Accelerated RGT scenario**, which includes an accelerated ramp-up of the renewable gas industry to more rapidly decarbonise the stationary energy sector and de-risk the development of the renewable gas sector. This accelerated adoption of renewable gas could be desirable if policy-makers wish to reduce the risk that renewable gas adoption will be hampered by logistical constraints, recognise the potential for renewable gases to underpin emerging export industries such as green hydrogen, green ammonia or green iron, or seek to hedge against potential difficulties in achieving abatement in other sectors of the economy.

We also undertook a number of sensitivities to assess how outcomes might vary under both different policy objectives, and if fuel and technology cost assumptions vary from those used in the core modelling. We undertook:

— a Sensitivity on the No Action scenario to examine emissions outcomes under existing policies – principally the Safeguard Mechanism and the Victorian and ACT residential connection bans – but assuming no further policy effort.

— six sensitivities on the Theoretical Efficient Policy scenario that varied key assumptions such as electrical appliance capital costs, hydrogen costs, and biomethane costs and availability. These sensitivities tested how outcomes may vary if technology trends vary from those assumed in the core modelling.

— a sensitivity on the Theoretical Efficient Policy scenario that used a tighter carbon budget and achieved net zero by 2045

— a sensitivity on the Theoretical Efficient Policy scenario that varied capital cost assumptions to assess what degree of change to this assumption would be needed to mimic gas consumption trends comparable to AEMO's Step Change scenario from its Gas Statement of Opportunities modelling

— various sensitivities that explored different RGT trajectories.

Methodology and assumptions 2

ACIL Allen's approach to the engagement was to draw upon and extend an existing sectoral modelling framework developed to support the Victorian Gas Substitution Roadmap in 2021. The core component of this framework was a model which mapped a least cost pathway to decarbonising gas use for Victoria and sought to minimise societal costs given applicable targets, policies and assumptions. This least-cost pathway can then inform policy but highlighting economically efficient ways to decarbonise existing gas uses, and how sensitive these pathways are to, for example, variations and uncertainties in assumptions and changes in the speed of transition.

For the purpose of this exercise, the modelling framework used for the 2021 Victorian Gas Substitution Roadmap has also been enhanced and extended to additional gas consumer cohorts and expanded to cover the whole of Australia. The following section provides an overview of the model, while the subsequent section outlines key assumptions within the model.

Throughout this report unless otherwise noted:

— years represent financial years ending 30 June

— financial amounts are expressed in real (inflation-adjusted) terms using a 2023 dollars as a basis.

2.1 Gas Transition Model

The Gas Transition Model (GTM) was developed to provide insights into the least cost pathways to decarbonise gas consumption. The model seeks to minimise societal resource costs to achieve abatement objectives which include specific annual CO_2 emission targets for 2030 and 2050 and an overall CO_2 emissions budget over the period modelled. Resource costs consist of the present value of capital and operating costs of meeting the energy demand which would otherwise have been met by the combustion of natural gas. For this exercise we have used a discount rate of 7% to calculate present values.

The GTM is formulated as a large-scale linear program (LP) with the objective function to minimise the present value of resource costs, subject to a range of constraints. Given its large scale, the model is solved using commercial mathematical optimisation solvers.

In developing the model structure, the following design principles were applied:

— Both demand and supply side solutions are available to meet abatement targets.

— The model examines the least cost pathway from a system planning perspective. It is not a consumer choice model and does not implement Government policies to encourage take-up of certain technologies unless constrained to do so.

— The model only considers economic costs (capital expenditure and operating costs) and does not attribute a cost to continuing to use existing assets.

— Existing end-user appliances must be replaced at the assumed end of their life, but early replacement is allowed if an acceleration of appliance replacement transition is economic given any emissions or other constraints imposed.

— Blending of renewable gases into natural gas network is permitted, with biomethane and synthetic methane considered perfect substitutes for natural gas and hydrogen blending limited to 3% by energy[1] into traditional gas networks and appliances until a conversion to hydrogen capable networks and appliances occurs.

— Emissions considered include those from combustion of natural gas. It does not consider fugitive emissions. Where electrification occurs, any incremental emissions associated with additional electricity generation to serve the electrified load are accounted for within the gas sector's emissions constraints (but the baseline level of emissions from gas-fired generation is accounted for within the electricity sector, which is subject to its own emission budget).

— Usage profiles for electric appliances match the time of day and seasonal profiles from equivalent gas appliances (i.e., no time shifting of usage is assumed to occur).

— The use of CO_2 emission offsets was avoided wherever possible for the purpose of gaining insights into the cost of abatement in the natural gas sector. The model has the option to use offsets in order to meet an emissions constraint where no other options were available (in which case, failing to offer offsets would have made the linear optimisation non-feasible).

2.1.1 Model formulation

The GTM objective function is to minimise the present value of the sum of capital[2] and operating costs as follows:

$$Min \sum_{i=1}^{n} PV_{Capex(NA,H2,H2C,BM,EN,GN)} + PV_{Opex(NA,H2\ ,BM,EN,CVP)}$$

Where:

— NA = New Appliances (gas, electric and hydrogen variations)

— H2 = Hydrogen electrolysers including associated infrastructure (pipelines) and either the capital cost of dedicated solar and wind production (for 'standalone' hydrogen production), or wholesale electricity costs as an operating cost for grid-connected hydrogen production.

— H2C = End user appliance conversion to accommodate 100% Hydrogen fuel

— BM = Biomethane production plants

— EN = Electricity transmission and distribution network infrastructure to meet increased peak demands

— GN = Gas network infrastructure to serve new customers

— CVP = emission offsets / constraint violation penalties[3]

Subject to a range of constraints including:

— Emissions must be less than or equal to

  – aggregate emission budget constraints for the periods 2025 to 2030 and 2025 to 2050

  – annual emissions constraints for each year from 2050 to 2060.

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[1] This is equivalent to a blend of 10% by volume. Higher blending rates may be possible.

[2] Capital cost items utilise an apportionment factor in situations where the economic life exceeds the model end period.

[3] These are used to ensure feasibility of the solution, with a post model adjustment undertaken in line with the assumed cost of offsets.

- Selected appliance switching constraints in the near-term to reflect limitations of consumer ability to switch to alternatives and available technologies (i.e., hydrogen ready appliances are not widely available at present)
- An energy balance constraint which forces all energy demand within model scope to be met each period
- All appliances which reach end-of-life (or prior if emissions constraints dictate) are replaced with an equivalent gas, electric or hydrogen variant (annual appliance stock model constraint: $Stock_y = Stock_{y-1}$ – EndofLife + New)
- Demand for appliances in new dwellings and business premises is met
- Hydrogen blending within the gas stream is limited in aggregate to 3% by energy unless a complete appliance conversion is undertaken.

2.1.2 Solution space

The GTM selects the combination of appliances and supply technologies which minimises resource costs. This can include:

- End users are broken down into representative cohorts
- End users purchasing a replacement natural gas appliance and continuing to consume natural gas
- Developing biomethane production facilities to supplement natural gas sources with a lower emissions profile
- End users switching to an electric appliance with the model accounting for increases in wholesale load-weighted electricity prices, transmission and distribution costs (where peak demand increases)
- End users switching to a hydrogen appliance where full hydrogen conversion has occurred
- Developing hydrogen supply sources, transmission and storage infrastructure to blend into the natural gas stream or supply 100% of the gas stream if full hydrogen conversion has occurred.

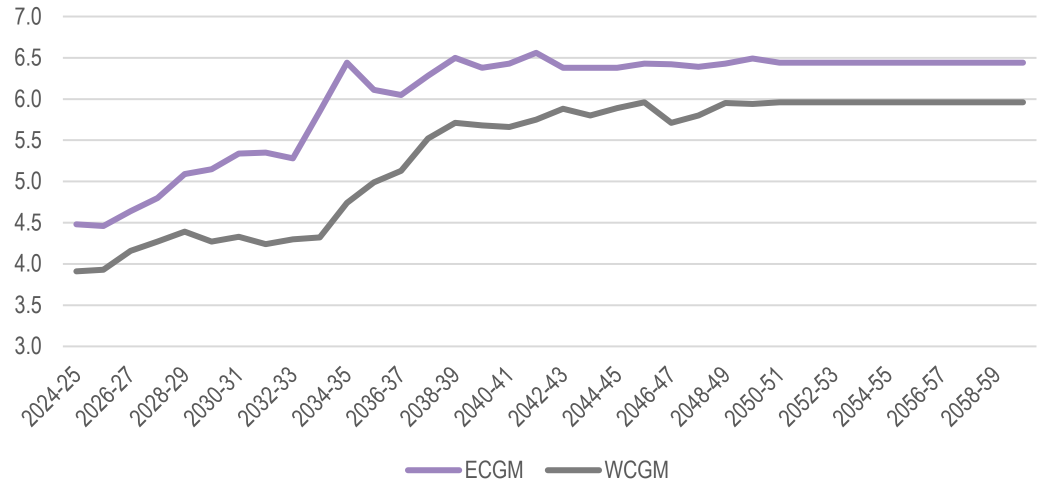
2.2 Key inputs

Natural gas prices

ACIL Allen was recently engaged by AEMO to undertake price projections to inform the Annual Inputs and Assumptions Report (IASR) and Gas Statement of Opportunity for 2024 within the East Coast Gas Market (ECGM) and Northern Territory. As a part of this work, ACIL Allen aligned key gas market assumptions within our proprietary modelling software GasMark Global (GasMark) with AEMO's assumptions. We used GasMark to generate projections of future supply demand balance and estimate wholesale gas prices based on these assumptions for the ECGM, and based on our in-house market assumptions for the west coast gas market (WCGM). For each market we examined cost and price outcomes under high and low demand cases, reflecting significant uncertainties in the future of the gas market, and used these estimates to estimate the resource cost per unit of gas production. These costs are less than wholesale gas price outcomes which include a profit margin to producers over the raw cost of extraction.

The results of these projections are presented in Figure 2.1. Further details on the methodology used to derive the wholesale gas price series used in the GTM are provided in Appendix A.

Figure 2.1 Resource cost per unit of gas production, by market ($/GJ)



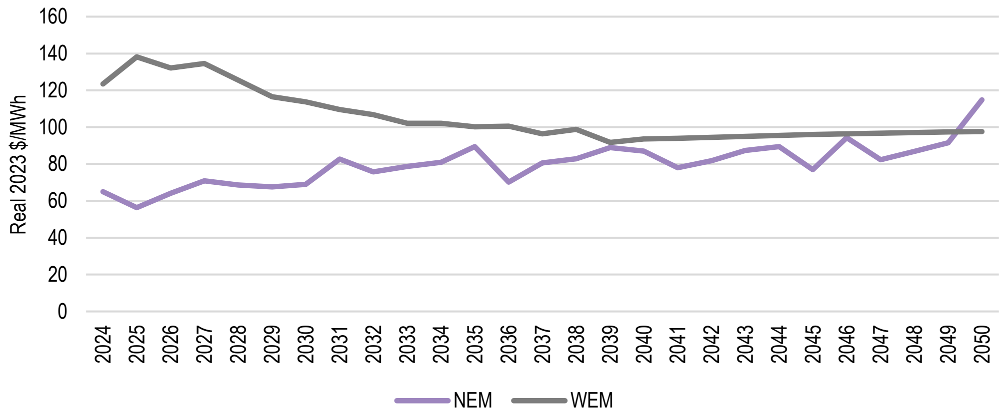
Source: ACIL Allen GasMark modelling

Wholesale electricity prices

The resource cost approach for electricity has drawn from AEMO's 2022 Integrated System Plan (ISP) modelling for the National Electricity Market (NEM). ACIL Allen has utilised the Plexos modelling platform and AEMO's published input databases to run the ISP Step Change scenario and extract load-weighted price outcomes from this least cost planning scenario.

As there is no comparable ISP dataset for Western Australia, ACIL Allen has drawn from its internal Reference case projection for the Western Australian Wholesale Electricity Market. This scenario utilised AEMO inputs for demand from the 2023 WA Electricity Statement of Opportunities (WA ESOO) report. The cost series for the WEM reflects the load-weighted price outcome from the real-time energy market plus projected reserve capacity market costs. WEM electricity costs are also applied to the North-West Interconnected System and Northern Territory.

Figure 2.2 Resource cost per unit of electricity, by market ($/MWh)



Source: ACIL Allen modelling

Further details on the methodology used to derive the wholesale electricity price series used in the GTM are provided in Appendix B.

Hydrogen production costs

ACIL Allen modelled two primary hydrogen production cost series:

- A firmed hydrogen series based on 'standalone' production, that is, dedicated solar and wind generation, electrolysers, storage and pipelines with no interaction with the wider electricity grid
- An unfirmed series based on small-scale grid-connected production, suitable for opportunistic blending into the wider natural gas stream.

The table below summarises the core assumptions used to estimate the cost components under each approach.

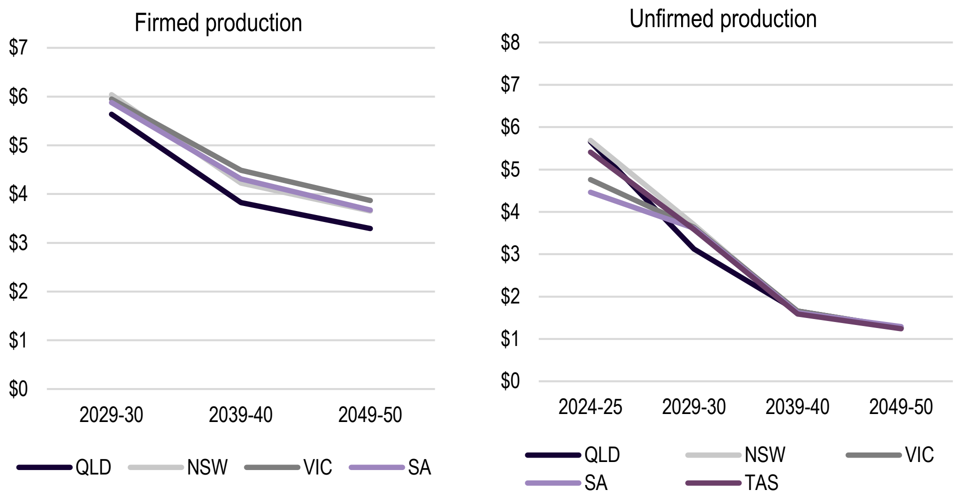
Table 2.1 Key assumptions on hydrogen production costs

Cost component	Firmed hydrogen	Unfirmed hydrogen
Electricity costs	Solar and wind costs and REZ-specific generation traces based on 2022 ISP assumptions Baseload plant power requirements costed based on ACIL Allen *PowerMark* electricity market modelling	Wholesale electricity prices from ACIL Allen *PowerMark* electricity market modelling, used for both electrolyser operation and baseload plant power requirement assumptions
Electrolyser costs	Alkaline electrolyser costs from CSIRO GenCost study (2021 study for consistency with 2022 ISP) 2022 ISP electrolyser efficiency assumption	
Hydrogen storage	Salt cavern and lined rock cavern costs based on Papadias and Ahluwalia (2021)	Not applicable
Pipeline transportation	Based on GPA Engineering (2022)	Not applicable
Baseload plant power requirements	1% of rated electrolyser capacity	2% of rated electrolyser capacity
Water costs	Aurecon assumptions for the 2022 ISP	

Source: ACIL Allen analysis based on the source cited.

Based on these assumptions we estimated the hydrogen production cost series presented in Figure 2.3.

Figure 2.3 Hydrogen production cost series (2023$/kg)



Source: ACIL Allen analysis

We note that the firmed hydrogen production cost series above is higher than some projections for this commodity, and also that it is above the widely-discussed target of $2 per kilogram, whether expressed in Australian or US dollars (we project unfirmed production costs to go below this level, but only in limited volumes). As with any such long-term projections, there is a degree of uncertainty and the modelled results reflect the particular set of assumptions used (see Table 2.1). Given this uncertainty, both higher and lower cost outcomes are possible.

Further details on the methodology used to derive the hydrogen cost series used in the GTM are provided in Appendix C.

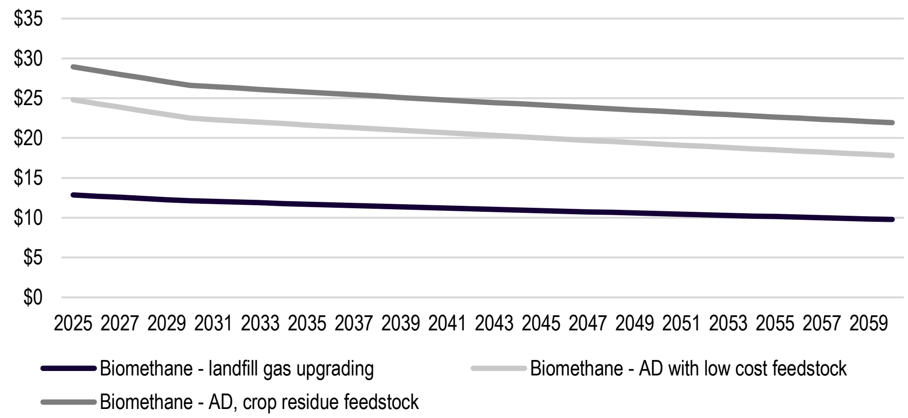
Biomethane production costs and volumes

ACIL Allen adopted biomethane costs based on estimates published in Australia's Bioenergy Roadmap, for three core cost series:

— Landfill gas upgrading, based on the landfill gas biomethane capital expenditure series from the Bioenergy Roadmap and an assumed zero feedstock cost[4]
— Anaerobic digestion based on low-cost feedstocks, based on the anaerobic digestion capital expenditure series from the Bioenergy Roadmap and an assumed zero feedstock cost (reflecting that feedstocks such as wastewater treatment sludge and food processing waste are available in concentrated amounts and do not need to be collected or purchased)
— Anaerobic digestion based on crop residue feedstocks, which also uses the Bioenergy Roadmap capital expenditure series for anaerobic digestion, and an assumed $4.1 per gigajoule cost reflecting the cost of feedstock collection and transport (also from the Bioenergy Roadmap).

Figure 2.4 presents the resulting biomethane cost series.

Figure 2.4 Biomethane cost series ($/GJ)



Source: ACIL Allen analysis of Enea and Deloitte 2021, Australia's Bioenergy Roadmap, https://arena.gov.au/knowledge-bank/australias-bioenergy-roadmap-report/, adjusted for inflation using ABS CPI data

Biomethane production of each type is limited in practice by the amount of available feedstock, the existence of competing uses for some feedstocks (such as the use of wheat stubble for animal feed) and practical limits on the timely and cost-effective collection of feedstock from various locations.

[4] Most large landfills capture methane for regulatory reasons and/or because these facilities can create ACCUs for methane destruction or create LGCs from electricity generation. The incremental cost of landfill gas capture from these sites is essentially zero. In essence, we are offering the model the chance to put the uncommercialised resource into biomethane pre-2030, and 90% of the theoretical resource post-2030.

ACIL Allen used two primary sources to estimate the available volumes of biomethane in each state:

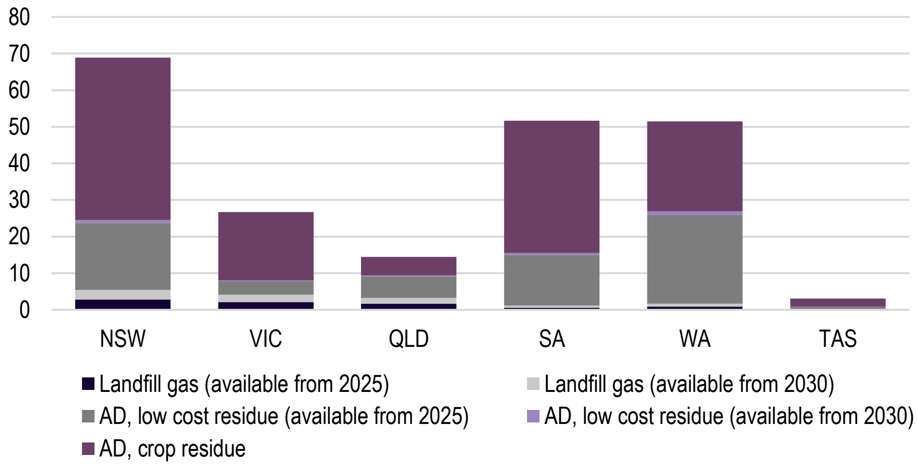
— The Bioenergy Roadmap, which includes estimates of the various types of bioenergy feedstocks by state

— Analysis by Enea Consulting for Energy Network Australia[5] that details the volume of feedstock suitable for anaerobic digestion by state.

Together these sources allowed us to identify the volume of anaerobic digestion suitable feedstock by state, separated into three core categories (landfill gas, low cost feedstock and crop residue feedstock). We made further minor adjustments to limit pre-2030 volumes to reflect existing uses of landfill gas and anaerobic digestion-derived biogas for electricity generation under the Large-scale Renewable Energy Target, which expires in 2030. The biogas associated with these existing uses are available for upgrading to biomethane from 2030.

Figure 2.5 presents our assumptions on assumed maximum biomethane production volumes based on these assumptions.

Figure 2.5 Maximum biomethane production volumes, by type and state (PJ/year)



Notes: AD = anaerobic digestion. No biomethane production is assumed in the ACT or NT.

Source: ACIL Allen analysis

Synthetic methane production costs

We modelled synthetic methane that was derived from the biogenic (and therefore carbon neutral) carbon dioxide produced as part of the biomethane upgrading process, and firmed hydrogen. We assumed that the waste carbon dioxide from biomethane upgrading would be available at zero cost, and hydrogen costs based on the firmed production costs detailed in Figure 2.3. We further assumed that the direct costs of methanation plant were $20.8 million per petajoule of annual production capacity.[6]

Based on the molecular mass ratio implied by the chemical formula for the methanation reaction, we assumed that the ratio of hydrogen input to synthetic methane output was 1-to-2 by mass, which translates to a ratio of about 1.2-to-1 by energy when adjusting for the relative energy

[5] Enea 2022, 2030 emission reduction opportunities for gas networks, https://www.energynetworks.com.au/miscellaneous/2030-emission-reduction-opportunities-for-gas-networks-by-enea-consulting-2022/.

[6] ACIL Allen analysis of Götz et al 2016, Renewable power-to-gas: a technological and economic review, *Renewable Energy* 85 (1371-1390), https://www.sciencedirect.com/science/article/pii/S0960148115301610.

densities by mass of hydrogen and methane (142 MJ/kg and 55 MJ/kg respectively). As hydrogen is the primary cost component of synthetic methane when waste carbon dioxide is available, the cost of synthetic methane will always be at least 1.2 times the cost of firmed hydrogen available in each state (see Figure 2.3), with a modest additional cost of the methanation plant itself.

The volume of synthetic methane is limited based on the volume of carbon dioxide available from the biomethane upgrading process. Based on typical carbon dioxide concentrations of landfill gas and biogas from anaerobic digestion[7], we estimated that the volume of synthetic methane was limited to 58% of the landfill gas derived biomethane, and 65% of the biomethane produced from anaerobic digestion.

Energy demand calibration by state, industry and activity

ACIL Allen used Table F of the Australian Energy Statistics[8] as the core data set for calibrating the baseline level of natural gas consumption across jurisdictions and industries. However, this data has too high a level of aggregation to suit all modelling purposes for two main reasons:

— Industry level gas use aggregates distinct activities that have different economics (such as residential cooking and heating), and so industry level data must be disaggregated to an activity level to model the underlying economics.

— State and territory level data is often obscured in Table F for confidentiality reasons, and so other sources must be used to fill gaps. At the extreme, Table F does not publish data for the ACT, which is aggregated within NSW gas demand.

We further used detailed sources such as AEMO's Gas Bulletin Boards (for both east coast and west coast markets), Australian Government published data on emissions by entities subject to the Safeguard Mechanism, gas industry statistics, gas distribution business demand forecasts and industry studies to disaggregate data to the necessary level of activity-based geographic detail.

Table 2.2 summarises the industry and activity categories at the level of disaggregation presented to the model.

Table 2.2 Modelled industry and activity categories

User type	Industry	Activity
Industrial	Agriculture, forestry and fishing	Low-temperature heat
Industrial	LNG	Compression
Industrial	Gas processing	Compression
Industrial	Gas processing	High temperature heat
Industrial	Other mining	High temperature heat
Industrial	Food, beverages and tobacco	Low-temperature heat
Industrial	Food, beverages and tobacco	High temperature heat
Industrial	Pulp, paper and printing	High temperature heat
Industrial	Petroleum and coal products	High temperature heat
Industrial	Ammonia and derivatives	Ammonia synthesis
Industrial	Ammonia and derivatives	Urea

[7] RACE for 2030, 2023, Anaerobic digestion for electricity, transport and gas https://racefor2030.com.au/wp-content/uploads/2023/04/21.B5-OA_-Final.pdf

[8] Australian Government 2022, Australian Energy Update 2022: Table F – Australian energy consumption, by state and territory, by industry and fuel, energy units, https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202022%20Table%20F_.xlsx.

User type	Industry	Activity
Industrial	Other chemicals	High temperature heat
Industrial	Glass and glass products	Glass making
Industrial	Other non-metallic minerals	Calcining
Industrial	Iron and steel	Metal reheat
Industrial	Iron and steel	High temperature heat
Industrial	Alumina	Calcining
Industrial	Alumina	Digestion
Industrial	Other non-ferrous metals	High temperature heat
Industrial	Fabricating, machinery and equipment	Metal reheat
Industrial	Other manufacturing	Low-temperature heat
Industrial	Other manufacturing	High temperature heat
Industrial	LNG	On-site power generation
Industrial	Gas distribution	Low-temperature heat
Industrial	Water supply, sewerage and drainage	Low-temperature heat
Commercial	Commercial and services	Commercial cooking
Commercial	Commercial and services	Commercial hot water
Commercial	Commercial and services	Commercial space heating
Commercial	Gas transmission	Compression
Residential	Residential - existing	Residential cooking
Residential	Residential - existing	Residential hot water
Residential	Residential - existing	Residential heating – small
Residential	Residential - existing	Residential heating – large
Residential	Residential - new	Residential cooking
Residential	Residential - new	Residential hot water
Residential	Residential - new	Residential heating – small
Residential	Residential - new	Residential heating – large

Source: ACIL Allen analysis based on the sources cited.

Estimation of appliance stock and underlying energy demand

The purpose of the model is to make choices about appliances and fuels in an economically efficient way in response to emissions constraints or other decarbonisation policies. As a result, we need to convert the observed level of gas demand into an underlying ‘energy task’, that could be met by, for example, natural gas, electricity or hydrogen. This is particularly important as the efficiencies of gaseous fuel and electrical appliances are very different in some cases, so the level of energy input to serve the same underlying energy task can also be very different.

Table 2.3 compares the efficiencies of gaseous fuels and electrical appliances across the various activities modelled.

Table 2.3 Comparative efficiencies of gaseous fuels and electrical appliances, by activity

Activity	Efficiency metric	Natural gas appliance	Electrical appliance	Hydrogen appliance
Low temperature heat	%	85%	300%	85%

Activity	Efficiency metric	Natural gas appliance	Electrical appliance	Hydrogen appliance
Compression	%	30%	94%	30%
High temperature heat	%	65%	85%	65%
Ammonia synthesis	TJ/ktpa (capacity)	28.6	N/A	19.2
Urea	TJ/ktpa (capacity)	16.7	N/A	9.6
Glass making	%	50%	85%	50%
Calcining	%	65%	N/A	65%
Metal reheat	%	65%	75%	65%
Digestion	%	80%	330%	80%
LNG power generation	%	36%	100%	36%
Commercial cooking	%	30%	85%	30%
Commercial hot water	%	85%	350%	85%
Commercial space heating	%	80%	300%	80%
Residential cooking	%	30%	85%	30%
Residential hot water	%	85%	95% - 350%	85%
Residential heating - small	%	80%	400%	80%
Residential heating - large	%	80%	300%	80%

Note: the lower efficiency for residential hot water is for a resistive electric water heater; the higher efficiency is for a heat pump water heater. Ammonia and urea are feedstock applications and therefore electrification is not possible. For calcining, electrification is theoretically possible (e.g. alumina calcining is being researched as part of an ARENA study) but we have no basis on which to estimate capital costs as the technology is really only theoretical at this stage.

Source: ACIL Allen analysis

We then converted the implied energy task to an appliance stock and projected this stock based on expected growth in activity in the relevant sectors. This conversion was applied differently for different sectors:

— For the industrial sector the stock was expressed as megawatts of thermal or compression load (as relevant), or as kilotonnes of annual production capacity for the ammonia synthesis and urea activities

— For the LNG industry, growth in underlying energy demand was calibrated to the Australian Government's estimates for LNG stationary energy emissions[9]

— For major gas-using sectors such as alumina, ammonia, urea, iron and steel and petroleum and coal products, underlying energy demand was held constant over the projection except for adjustments for known closures and plant openings

— For other industrial and sectors and the commercial sector, energy demand was grown in line with broader macroeconomic projections of activity in the wider sector (estimated to be 1% per year)

[9] Australian Government 2022, Australia's emissions projections 2022 https://www.dcceew.gov.au/sites/default/files/documents/australias-emissions-projections-2022.pdf

- For the residential sector:
  - Gas demand was converted into estimates of total appliance numbers based on a study of residential energy demand commissioned by the Australian Government[10]
  - The appliance stock in existing houses was reduced progressively over time to reflect housing demolitions, based on ABS housing data[11]
  - The appliance stock in new houses was grown over time to reflect ABS household projections[12], with appliance penetration calibrated base on the residential baseline study.[13]

Appliance capital costs and operating life

Capital costs are an important driver of the model's appliance and fuel choices. Given the diversity of energy tasks and appliances available to the model, these assumptions were based on a broad range of studies. For industrial activities, capital cost assumptions were based on a broad range of activity-specific studies for industrial applications. For residential activities, we primarily relied on a study undertaken for the Gas Appliance Manufacturers' Association of Australia, which detailed cooktop, hot water and heating cost assumptions across several house 'archetypes'.[14] From this study we:

- Adopted typical (rather than high or low) costs for homes from archetype 1 (large houses) for cooking, hot water and large heating activities, and typical costs from homes from archetype 3 for small heating (adjusting from the modelled two heating units to a single unit)
- Pro-rated appliance removal and rectification costs across the different appliance types for installations in existing homes, but not for new homes
- Applied the electricity connection upgrade cost to heaters in existing homes, but not to other appliances
- Applied a hydrogen appliance cost uplift consistent with that used in the study to estimate the costs of hydrogen appliances.

To further reflect the diversity of housing appliance stocks, we separated the heating task in existing homes into additional categories, based on observed appliance uptakes in the residential baseline study.[15] These categories reflected whether existing homes moving from gas to electrical heating already had one or two reverse cycle air-conditioners (which are commonly installed for cooling purposes but also offer heating). We also adjusted capital costs for new homes based on their assumed cooling choices:

- For small heaters, we assumed that a proportion of homes would choose a reverse-cycle air-conditioner for cooling purposes in any case, in which case the capital cost of adopting electric heating in one room is zero
- For large heaters, we assumed that households would either choose an evaporative cooler as well as gas ducted heating, or alternatively whole-of-house reverse-cycle air-conditioning, and

[10] EnergyConsult 2022, 2021 Residential Baseline study for Australia and New Zealand for 2000-2040, https://www.energyrating.gov.au/sites/default/files/2022-12/2021%20RBS_OutputTablesV1.9.2-AU.xlsx

[11] ABS 2022, Estimated dwelling stock, https://www.abs.gov.au/statistics/industry/building-and-construction/estimated-dwelling-stock/latest-release

[12] ABS 2019, Household and family projections, Australia, https://www.abs.gov.au/statistics/people/population/household-and-family-projections-australia/latest-release

[13] EnergyConsult 2022.

[14] Frontier Economics 2022, Cost of switching from gas to electric appliances in the home, https://gamaa.asn.au/wp-content/uploads/2022/07/Frontier-Economics-Report-GAMAA.pdf.

[15] EnergyConsult 2022.

so we added the capital cost of an evaporative cooler on to those of the gas ducted heating to ensure a like-for-like comparison.

Table 2.4 summarises the key capital cost and appliance life assumptions used in the modelling.

Table 2.4 Appliance capital cost and operating life assumptions

		Capital cost			Appliance life (years)	
Activity (by size)	Capital cost unit basis	Natural gas appliance	Electrical appliance	Hydrogen appliance	Gaseous fuels appliance	Electrical appliance
Low temperature heat	$\$m/MW_{th}$	0.5	1.3	0.65	20	15
High temperature heat (small)	$\$m/MW_{th}$	0.4	0.4	0.5	25	25
High temperature heat (medium)	$\$m/MW_{th}$	0.3	0.3	0.4	25	25
Metal reheat (small)	$\$m/MW_{th}$	0.5	1.7	0.7	20	15
Metal reheat (medium)	$\$m/MW_{th}$	0.3	1.5	0.4	20	15
Compression (medium)	$m/MW	6.4	7.8	6.4	25	25
Compression (large)	$m/MW	3.5	4.3	3.5	25	25
Glass making	$\$m/MW_{th}$	1.5	1.5	1.6	20	20
Calcining (medium)	$\$m/MW_{th}$	1.5	N/A	1.6	30	30
Calcining (large)	$\$m/MW_{th}$	1.5	N/A	1.6	30	30
Digestion	$\$m/MW_{th}$	0.3	1.7	0.4	20	15
Ammonia synthesis	$m/ktpa (capacity)	1.9	N/A	1.5	25	25
Urea	$m/ktpa (capacity)	2.7	N/A	0.8	25	25
LNG power generation	$m/MW	1.5	0.2	N/A	25	40
Commercial cooking	$\$m/MW_{th}$	0.2	0.3	0.3	20	15
Commercial hot water	$\$m/MW_{th}$	0.8	1.3	0.9	15	15
Commercial space heating	$\$m/MW_{th}$	0.5	0.8	0.5	20	15
Residential cooking - existing	$000/ appliance	2.0	2.7	2.2	20	15
Residential hot water - existing	$000/ appliance	3.2	2.9 (resistive) 5.4 (heat pump)	3.6	15	15
Residential heating - existing - no RCAC installed (small)	$000/ appliance	2.9	3.5	3.3	20	15
Residential heating - existing – 1 RCAC installed (small)	$000/ appliance	2.9	0	3.3	20	15
Residential heating - existing - no RCAC installed (large)	$000/ appliance	10.8	21.8	12.2	20	15
Residential heating - existing - 1 RCAC installed (large)	$000/ appliance	10.8	18.4	12.2	20	15
Residential heating – existing - 2 RCAC installed (large)	$000/ appliance	10.8	14.9	12.2	20	15
Residential cooking - new	$000/ appliance	3.1	2.4	3.3	20	15

Activity (by size)	Capital cost unit basis	Capital cost			Appliance life (years)	
		Natural gas appliance	Electrical appliance	Hydrogen appliance	Gaseous fuels appliance	Electrical appliance
Residential hot water - new	$000/ appliance	4.1	2.6 (resistive) 4.8 (heat pump)	4.5	20	15
Residential heating - new - no air-conditioning (small)	$000/ appliance	3.9	3.2	2.8	20	15
Residential heating - new – with air-conditioning (small)	$000/ appliance	3.9	0	4.2	20	15
Residential heating - large - new	$000/ appliance	10.6	17.6	11.9	20	15

Note: Capital costs for natural gas appliances for large houses are inclusive of both heating and cooling appliances, as a cooling appliance is needed to provide a comparable service to the reverse-cycle air-conditioner (RCAC) costed as the electrical option. We have assumed an evaporative ducted cooling unit, following Frontier Economics 2022. For existing houses with installed RCAC units, the cost of new electrical appliances is reduced to reflect that fewer new units need to be installed. For small houses with air-conditioning, no capital cost is assumed for electrical heating as we assume that the existing unit is an RCAC. Asset lives and capital costs for electrical option for LNG power generation is for on-site network connection costs only (e.g. connection transformers) – generation capital costs are internalised within the wholesale price of electricity.

Source: ACIL Allen analysis

Carbon budgets

The overall carbon budget for gas-using sectors in scenarios with explicit decarbonisation objectives was set so as to be consistent with the Australian Government’s overall emissions reduction objectives, principally:

— a 43% reduction in national emissions on 2005 levels by 2030

— net zero emissions by 2050.

Further, given that many large gas users are subject to the federal Safeguard Mechanism, we took into account the implied reduction in emissions required of those entities given the emissions budget estimated for Safeguard entities over the period to 2030.

Over the period to 2030, we estimated a stationary energy emissions trajectory that reflected a weighted average of the implied Safeguard Mechanism emissions budget to 2030 and the unconstrained stationary energy emissions projection from Australia’s emissions projections, reflecting that about 70% of stationary energy gas use is subject to the Safeguard Mechanism. When we included this estimate alongside national projections of electricity, transport and other sectors’ emissions, we found that this approach was consistent with the national objective of a 43% reduction by 2030.

Beyond 2030, we assumed a straight-line reduction in emissions from the estimated 2030 level to net zero by 2050.

To allow for some flexibility to achieve abatement earlier or later than implied by these trajectories, we converted the annual emissions estimates into two ‘emissions budgets’ that limit total emissions over a defined period. These budgets were:

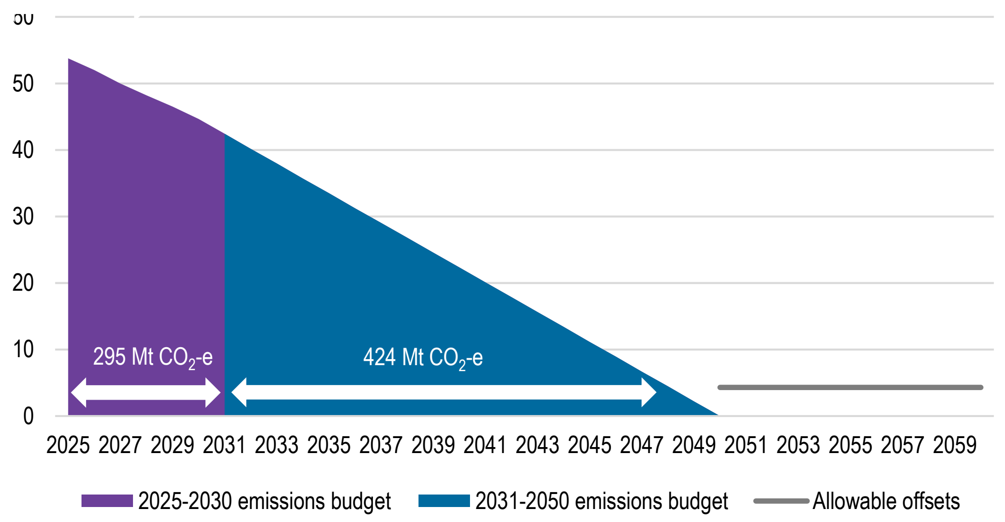
— 295 Mt CO_2-e for the period 2025 to 2030 inclusive

— 424 Mt CO_2-e for the period 2031 to 2050 inclusive (or an implied total budget of 719 Mt CO_2-e for the period 2025 to 2050).

For the period 2050 to 2060 inclusive we required the model to achieve zero net emissions in each year, while allowing the model to purchase offsets at $300/t$CO_2$-e if necessary to net out any residual emissions. To avoid over-reliance on offsets and illustrate feasible transition pathways for the gas sector, we only allow offsets to be used from 2050, and a maximum of 4.3 Mt CO_2-e of offsets can be used in each year (this number broadly reflects the gas sector's pro-rata share of current levels of negative emissions from the land use, land use change and forestry sector, and so ensures that the gas sector is not overly reliant on offsets post-2050).

Figure 2.6 illustrates how the gas sector carbon budget for this analysis was calculated, as well as the maximum level of offsets that the model will allow to be used from 2050. While the carbon budget was calculated using straight-line extrapolation over two periods (2025 to 2030 and 2030 to 2050), emissions in any given year can vary from the notional trajectory presented and the key constraints for the model are the overall limits on cumulative emissions over the periods in question.

Figure 2.6 Illustration of calculation of net zero-consistent gas sector carbon budget and maximum allowable offsets (Mt CO_2-e)



Source: ACIL Allen analysis

In all scenarios we also applied a specific emissions budget to Safeguard Mechanism entities, to reflect the operation of this existing policy. The Safeguard budget operates alongside the sector-wide carbon budgets set out above.

For some sensitivities we examined outcomes when reducing emissions to net zero by 2045 rather than 2050 and adjusted the 2025 to 2045 budget to reflect a straight-line reduction from projected 2030 levels to net zero by 2045. This methodology gave an emissions budget of 608 Mt CO_2-e for the period 2025 to 2045 inclusive. Consistent with the 2050 net zero scenarios, we held emissions at net zero in each year from 2045 for the 2045 net zero sensitivities.

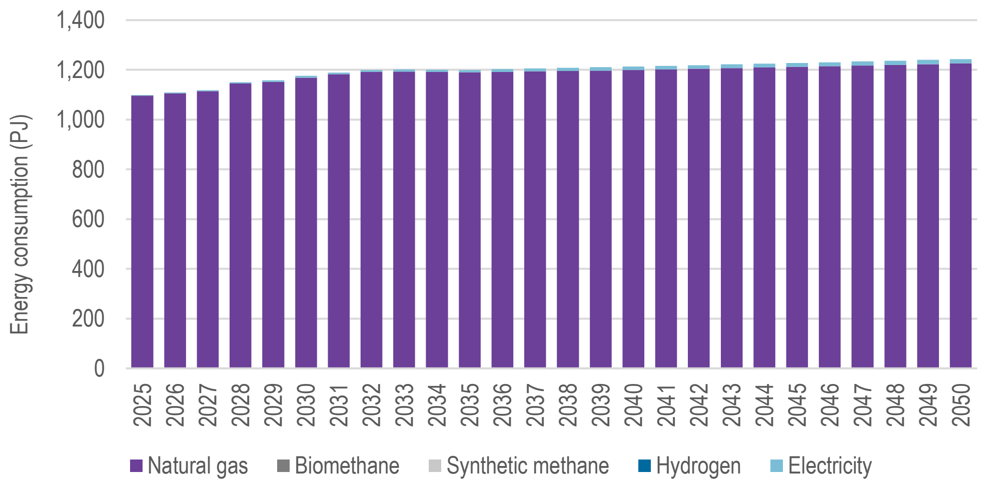
National outcomes 3

3.1 No Action scenario

The No Action scenario presents an outlook for the gas sector in the absence of any emission constraints. It is not a meaningful policy scenario as it clearly fails to achieve the common objectives of federal, state and territory governments to reach net zero emissions by 2050, and so we do not present detailed results for this scenario. Rather, the No Action scenario is used to calibrate emissions and economic outcomes in the model, for example, to calculate a cost of abatement based on the difference in emissions and costs between it and the various policy scenarios.

As the No Action scenario includes no explicit policy to reduce emissions (including implemented or announced policies such as the national Safeguard Mechanism, or the Victorian and ACT bans on new residential gas connections), natural gas use continues to grow in line with gas-using activities in the wider economy (Figure 3.1). The scenario sees small amounts of electrification where this is economic without any policy signal, primarily from cooking, water heating and some heating in new households, and heating in existing households with existing reverse-cycle air-conditioners. The total volume of electrification in the No Action is relatively small, amounting to just under 18 PJ (5 TWh) by 2050.

Figure 3.1 Fuel mix: No Action scenario (PJ)



Source: ACIL Allen Gas Transition Model

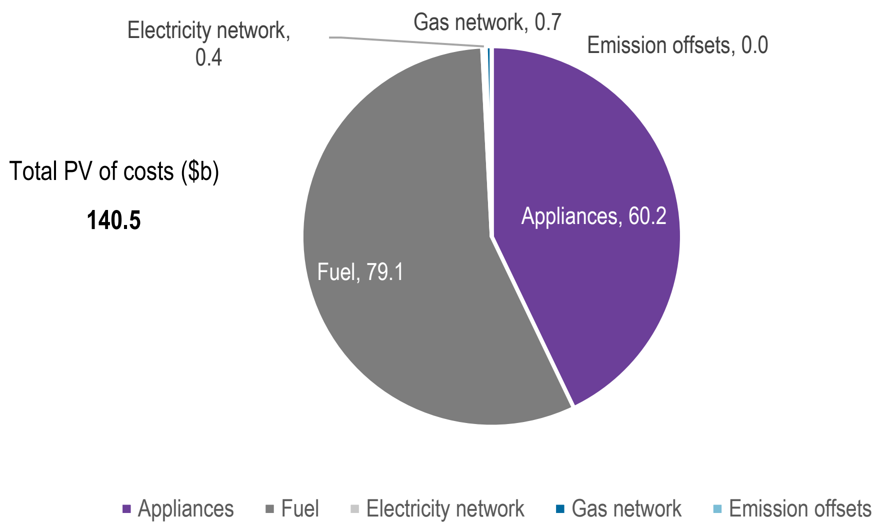
This continuing growth in gas use results in a slow but steady increase in greenhouse gas emissions from the gas sector – exceeding 60 Mt CO_2-e per year by 2030 and totalling almost 1.6 Gt CO_2-e over the period from 2025 to 2050 (Figure 3.2).

Figure 3.2 Gas sector emissions: No Action scenario (Mt CO_2-e)

Source: ACIL Allen Gas Transition Model

The present value of all costs in the No Action scenario is just over $140 billion (discounted at 7%). Figure 3.3 shows that the largest cost components are fuel costs and appliance costs, with very small costs associated with investing in electricity networks (to accommodate the small amount of electrification in this scenario) and gas networks (to connect new customers).

Figure 3.3 Present value of costs by category, 2025 to2060: No Action scenario (real 2023$b)



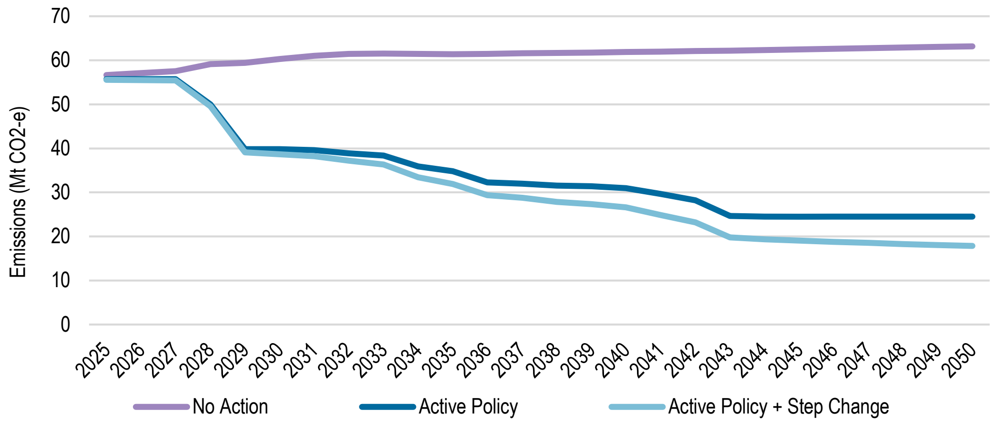
Note: present value calculated using a 7% discount rate
Source: ACIL Allen Gas Transition Model

Sensitivities exploring emissions outcomes under current policies

To understand the emissions trajectory of the gas sector under existing policies – principally the Safeguard Mechanism and the Victorian and ACT residential connection bans – we modelled a sensitivity that included the effects of these policies (the Active Policy sensitivity). We also explored a further sensitivity (Active Policy + Step Change) that assumed further electrification policy focused on the residential and commercial sectors that was consistent with the level of electrification in AEMO's Step Change scenario from its 2023 Gas Statement of Opportunities.

These sensitivities highlight that, while currently active policies appear sufficient to get the gas sector to a suitable abatement level for 2030, they are insufficient to achieve net zero emissions by 2050 (Figure 3.4). The Active Policy sensitivity results in emissions leveling off at around 24 Mt CO_2-e per year, while under the Active Policy + Step Change sensitivity annual emissions reduce to around 18 Mt CO_2-e over the same timeframe.

Figure 3.4 Emissions under policy sensitivities (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

These sensitivities highlight that further policy action is needed by governments to achieve net zero emissions in today's gas-using sectors.

3.2 Theoretical Efficient Policy scenario

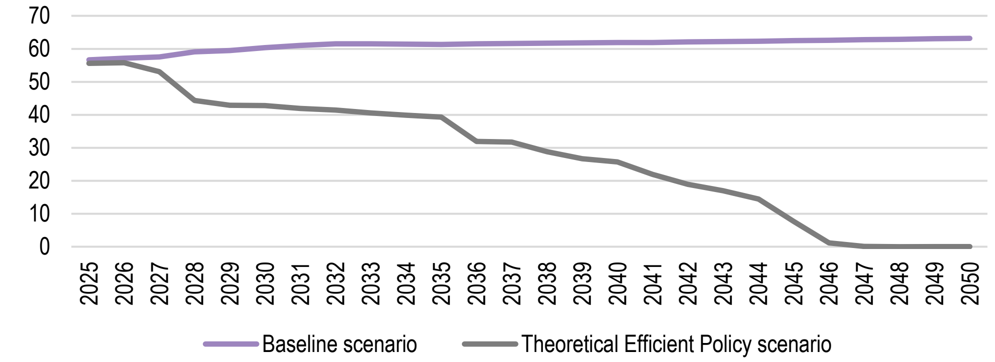
The Theoretical Efficient Policy scenario differs significantly from the No Action scenario in that it is designed to achieve net zero emissions by 2050 (consistent with government policy).

It is termed the Theoretical Efficient Policy scenario as the requirement to reduce emissions is included as an explicit constraint in the model, and the model will minimise the cost of achieving that emissions constraint in a way that reflects how a theoretical efficient policy framework such as a broad-based carbon price would work to reduce emissions. This 'policy-neutral' approach does not seek to represent individual emissions reduction policies within the model (for example, the Safeguard Mechanism or the Victorian and ACT bans on new residential gas connections), but rather seeks to give the model as much freedom as possible to identify the optimal way to reduce emissions given the input assumptions. In this way, the Theoretical Efficient Policy scenario provides a good benchmark for assessing the relative efficiency of alternative 'real world' policy approaches to achieving the same emissions outcome. While other scenarios will necessarily be higher cost than the Theoretical Efficient Policy scenario, we emphasise that the Theoretical Efficient Policy scenario is not practically achievable in Australia, given that broad-based carbon pricing is unlikely to be politically feasible in Australia in the foreseeable future. In this way, the Theoretical Efficient Policy scenario is a theoretical benchmark against which to assess potential policy approaches.

The Theoretical Efficient Policy scenario is forced to achieve emissions budgets defined for the periods 2025 to 2030 (295 Mt CO_2-e) and 2025 to 2050 (719 Mt CO_2-e), and to achieve net zero emissions in each year from 2050 (see section 2.2 for more detail on this constraint).

Figure 3.5 compares emissions in the Theoretical Efficient Policy scenario to the No Action scenario. Emissions fall to almost zero in the late 2040s. The emissions reduction trajectory includes a couple of notable step changes. The first step change is achieved by electrifying a number of LNG production facilities in 2027 and 2028, which the model sees this is a low cost means of contributing toward the 2030 emissions budget constraint. The second step down in the mid-2030s relates to further electrification of most of the remaining LNG capacity. Emissions reduce more consistently and rapidly from around 2039, reflecting significant increases in renewable gas production and use from that time, as well as ongoing electrification.

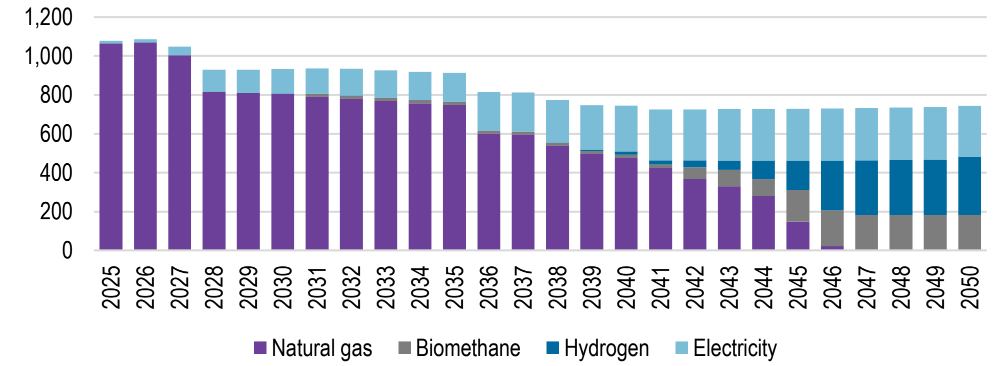
Figure 3.5 Emissions: Theoretical Efficient Policy scenario relative to No Action scenario (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

Figure 3.6 shows the mix of fuels used in the Theoretical Efficient Policy scenario. Electrification (primarily of LNG plants) plays the largest role during the 2020s and 2030s, but renewable gases (principally biomethane and hydrogen) play a greater role than electrification in the long-run, growing rapidly during the 2040s and reaching around 480 PJ by 2050 (compared to about 260 PJ from electricity).

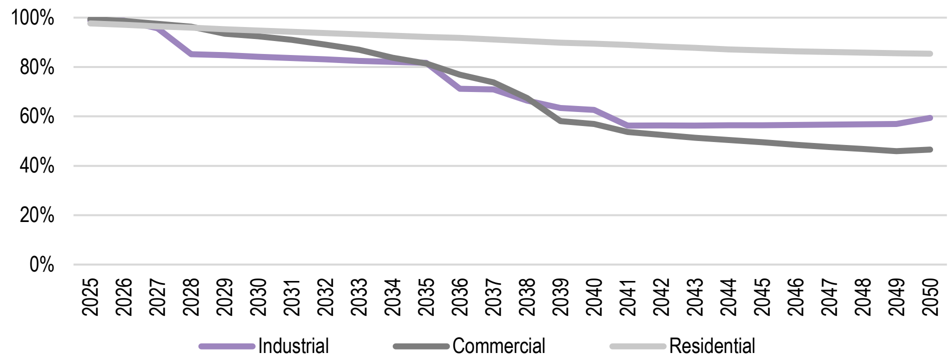
Figure 3.6 Fuel mix: Theoretical Efficient Policy scenario (PJ)



Source: ACIL Allen Gas Transition Model

Renewable gases and electrification play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector (Figure 3.7).

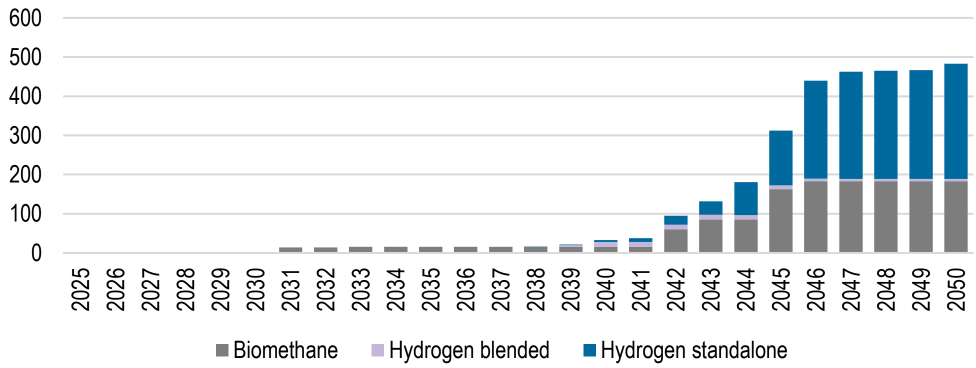
Figure 3.7 Theoretical Efficient Policy scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Figure 3.8 highlights the growing role of renewable gases as part of the fuel mix. Biomethane is initially developed from 2030 using low-cost sources such as landfill gas, before expanding to higher cost feedstocks such as crop residues, which are more scalable and allow it to ultimately supply about 180 PJ per year. Hydrogen begins to be used in ammonia production in 2036, before expanding rapidly during the 2040s to become the largest source of renewable gas supply (about 300 PJ by 2050). Some hydrogen blending into natural gas streams also occurs in fairly small volumes (up to 12 PJ per year).

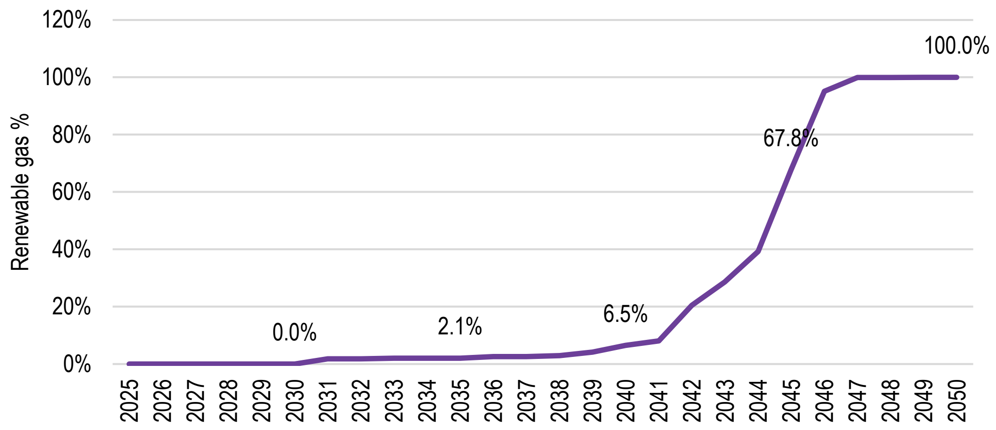
Figure 3.8 Development of renewable gases: Theoretical Efficient Policy scenario (PJ)



Source: ACIL Allen Gas Transition Model

The share of renewable gases in the wider gaseous fuel mix (Figure 3.9) ramps up slowly, reaching 1.8% by 2031 and 2.1% by 2035. The renewable gas share accelerates from 6.5% in 2040 to almost 68% by 2045 and reaches 100% in the late 2040s as conventional natural gas is removed from the system.

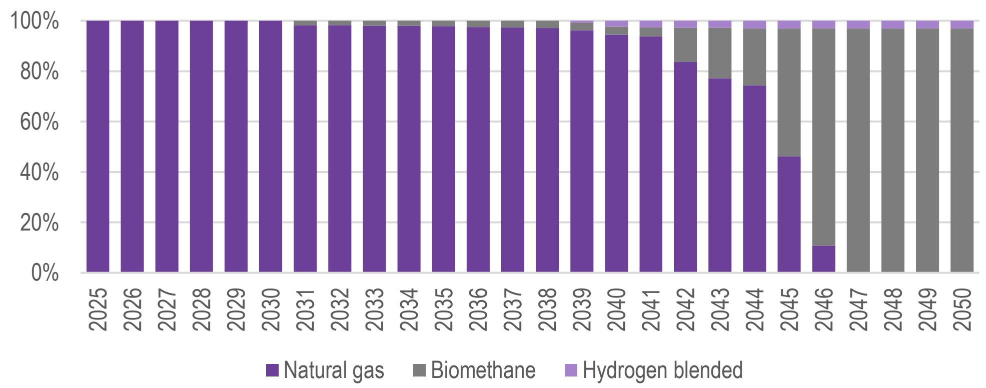
Figure 3.9 Renewable gas share: Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

The GTM allows users to either consume a blended gas product comprising natural gas, biomethane, synthetic methane and hydrogen (consistent with a hydrogen blending limit of up to 3%), or 100% hydrogen using dedicated hydrogen supply. Figure 3.10 examines the composition of the blended gas stream, that is, excluding dedicated hydrogen supply. This shows how the composition of gas supply will change, on average, for gas users that do not make specific adjustments to electrify or adopt hydrogen, and demonstrates how the share of biomethane in the blended gas stream grows rapidly during the 2040s to phase out natural gas use. A small portion of blended hydrogen is present from 2039 onwards.

Figure 3.10 Composition of blended gas stream, by gas type: Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

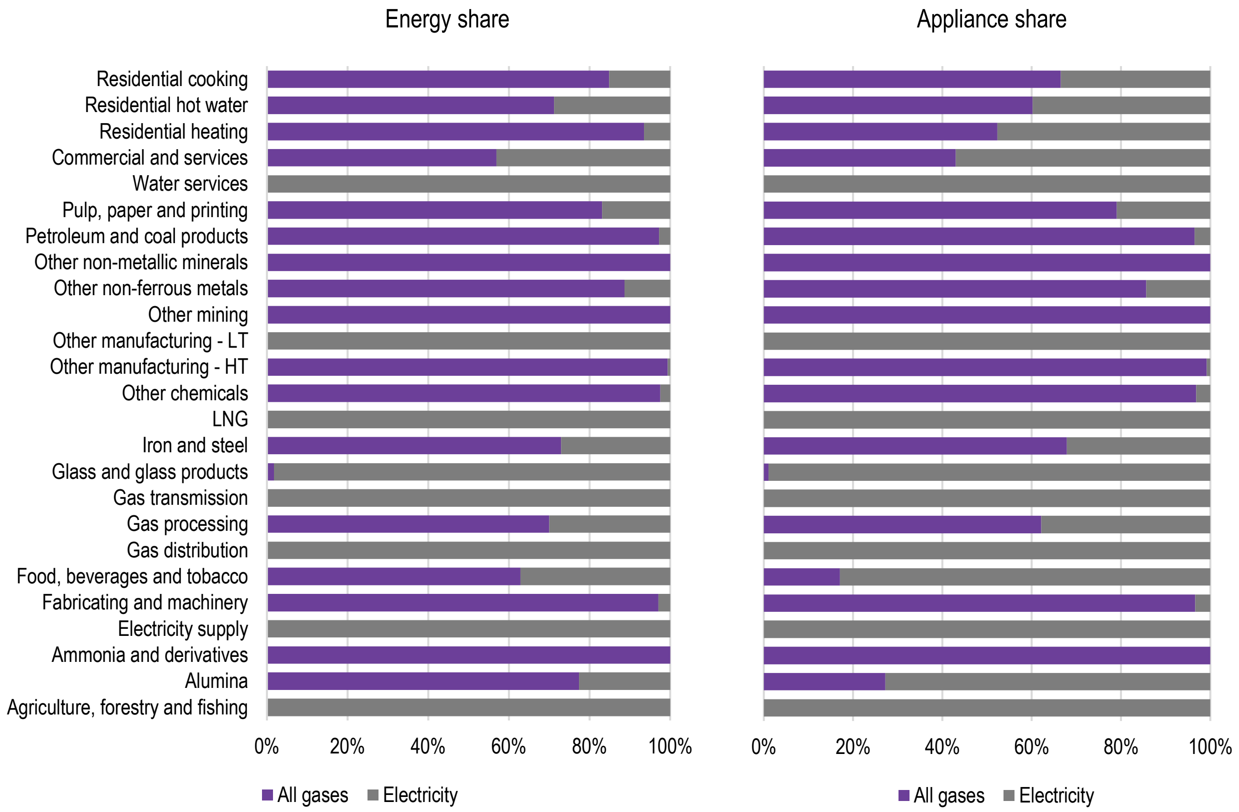
Figure 3.11 provides the energy and appliance use shares by sector in 2050. The ultimate mix of fuels is approximately two-thirds gaseous fuels and one-third electricity in 2050 but, importantly, the mix of fuels in individual sectors is varied and often includes a combination of both gaseous fuels and electricity. This indicates that renewable gases are useful energy sources for a range of sectors and policy-makers should be flexible and avoid one-size-fits-all approaches. Detailed sectoral level results as presented in Figure 3.11 should be treated with a degree of caution as each sector is represented by a small number of generalised activity types, and in practice users in some sectors will have a more diverse range of energy needs, and face different drivers and barriers when decarbonising. That said the sectoral trends reflect at a high-level the different economic of electrifying or using renewable gas in different sectors, for example:

— it is more economical to electrify low-temperature industrial processes than high-temperature industrial processes due to the ability to use heat pumps for low temperature processes

— compression requirements, such as in the LNG, gas processing and gas transportation sectors, are relatively economical to electrify

— feedstock activities as found in the ammonia and derivatives sector cannot be directly electrified and must use a gaseous feedstock.

Figure 3.11 Energy and appliance shares by sector and fuel type in 2050: Theoretical Efficient Policy scenario

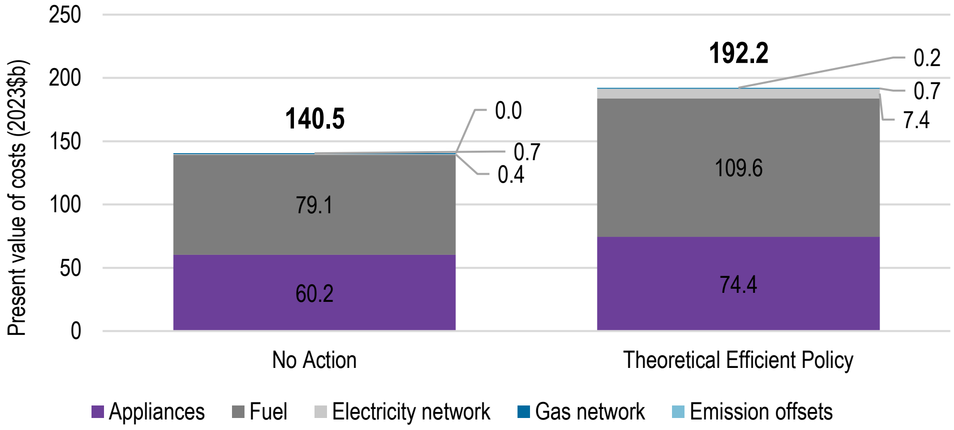


Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.12 compares the present value of costs in the Theoretical Efficient Policy scenario to those in the No Action scenario. The emissions reduction objectives in the Theoretical Efficient Policy scenario increase costs by around $52 billion relative to the No Action scenario, from about $140 billion to almost $192 billion. When compared to the abatement achieved relative to the No Action scenario, the Theoretical Efficient Policy scenario yields an average abatement cost of around $143/tonne CO_2-e.[16]

[16] To calculate a levelised cost of abatement, the difference in emissions must be calculated in present value terms (to compare to costs, which are also compared in present value terms). This is conceptually equivalent to accepted methods for calculating the levelised cost of energy (LCOE), which discounts both costs and energy production. The difference in the present value of emissions between the two scenarios is 367 Mt CO_2-e.

Figure 3.12 Present value of costs by category, 2025 to 2060: Theoretical Efficient Policy scenario compared to No Action scenario



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

As noted above, the outcomes under the Theoretical Efficient Policy scenario represent a theoretical optimal outcome where the sector is exposed to a uniform emissions budget and each end user made switching decisions (both the technology and timing of the switch) in a manner which resulted in the lowest overall resource cost outcome. In practice, end users are making individual decisions which maximise utility, given the relative prices they are exposed to, and policy and regulatory settings can only change those relative prices or limit the choices gas users may make.

Further, while the model can identify a least-cost outcome given the assumptions available to it in an environment of perfect foresight and complete knowledge, in practice, policy-makers and gas users both operate in an environment of imperfect information. For this reason, policy scenarios that reflect policies that are practically implementable will result in higher resource costs. Nevertheless, the Theoretical Efficient Policy scenario is a useful benchmark for comparing the relative efficiency of various real world policy scenarios, as discussed in subsequent sections.

3.2.1 Sensitivities on core model assumptions

We undertook six sensitivities on the Theoretical Efficient Policy scenario to assess how outcomes would vary overall, and at the sectoral level, in the event of plausible variations to the core model assumptions (Table 3.1). Sensitivity analysis supports robust policy-making for an uncertain future by illustrating how outcomes may vary if key technology and cost drivers vary from our core assumptions. This is important as future appliance and energy cost trends are inherently uncertain, particularly over long modelling timeframes. The logic of each sensitivity is explained below:

— We tested a number of hydrogen cost sensitivities but chose a 20% reduction in cost for the Hydrogen Cost sensitivity as it was sufficient to change a significant change in the overall and sector-level role of hydrogen, relative to both biomethane and electricity.

— The No Biomethane sensitivity explores a potential future where biomass suitable for biomethane production is diverted to sectors other than gas-using sectors, for example to provide renewable liquid fuels for hard-to-abate sectors such as aviation, shipping and long-distance land transport, and so is not available to the gas sector.

— The High Renewable Gas and High Electrification sensitivities explore 'stretch' outcomes when assumptions move favourable for renewable gas or electrification, respectively, to understand how this might affect the relative roles of gaseous fuels and electricity.

— The High Hydrogen and High Biomethane sensitivities focus on how the respective roles these two main renewable gas options might change if outcomes move favourably for one and unfavourably for the other.

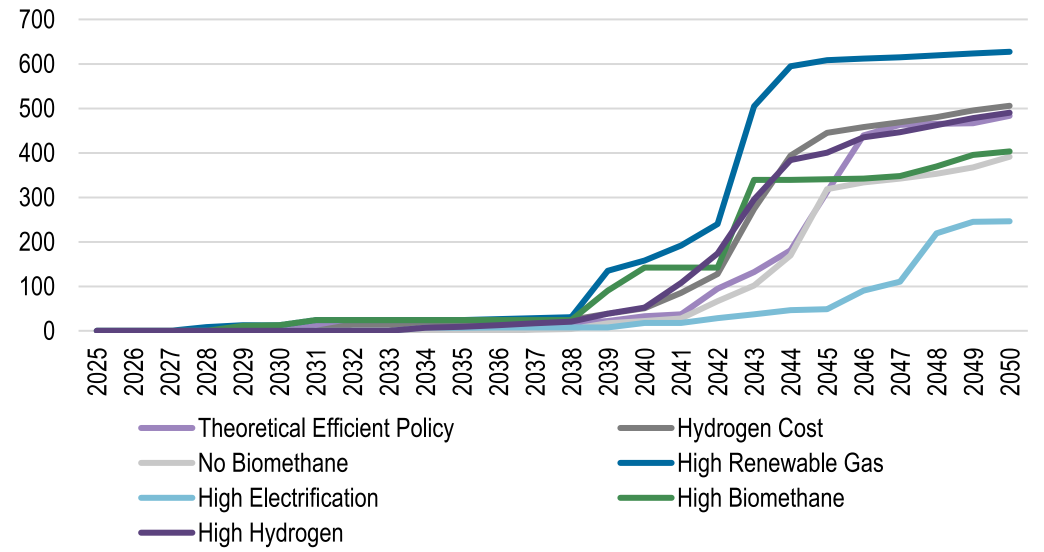
Table 3.1 Assumption variations for sensitivities

Sensitivity	Electrical appliance capital cost	Wholesale hydrogen cost	Wholesale biomethane cost	Biomethane availability (volume)
Hydrogen Cost		-20%		
No Biomethane				-100%
High Renewable Gas	+20%	-20%	-20%	+50%
High Electrification	-20%	+20%	+20%	-50%
High Hydrogen		-20%	+20%	-50%
High Biomethane		+20%	-20%	+50%

Source: ACIL Allen assumptions

The sensitivity analysis demonstrates that we can expect renewable gas to play a material role in decarbonising Australia, even if cost trends move favourably for electrification relative to our core assumptions. The High Electrification sensitivity still deploys about 250 PJ of renewable gas by 2050 to decarbonise Australia's existing gas-using sectors, while more than 600 PJ is needed by 2050 in the High Renewable Gas sensitivity (Figure 3.13). While the variation in results between the sensitivities show that the precise timing and scale of renewable gas development is uncertain, policy-makers can have a high degree of confidence that policies will be needed to support the development of a sizable renewable gas industry that is capable of supplying multiple hundreds of petajoules by 2050. Further, while these results indicate that renewable gas is primarily developed during the late 2030s and 2040s, the modelling results assume perfect foresight and do not include real world factors such as the time needed to develop industry capability, and so we consider that there is a strong policy argument for starting the development of renewable gas industry well before the modelled ramp up (see further discussion in section 3.4).

Figure 3.13 Renewable gas volumes (PJ): Theoretical Efficient Policy scenario compared to sensitivities



Source: ACIL Allen Gas Transition Model

The sensitivity analysis also gives insight into the potential role of gaseous fuels and electricity at the sectoral level (Figure 3.14). Across all gas-using sectors, the long-run share of energy supplied by gaseous fuels is between 50% and 75% under all sensitivities modelled, with most sensitivities around 65%. This gives a high degree of confidence that gaseous fuels will have a long-term role across many of today's gas-using sectors, and that renewable gases will play a material role in decarbonising these sectors.

Looking at the residential, commercial and industrial sectors separately, we can see that the volume of gaseous fuel used in the residential and commercial sectors varies more in response to changes in assumptions than the volume in the industrial sector:

— Gaseous fuels supply about 80% of energy or more in the residential sector under all sensitivities, except the High Electrification sensitivity, where it falls to below 50%.
— The share of energy supplied by gaseous fuels and electricity in the commercial sector is relatively well balanced in the long-run under most sensitivities, but the High Electrification sensitivity sees gaseous fuel use fall to zero by 2050.[17]
— The industrial sector sees gaseous fuels supply the majority of energy (more than 50%), even under the High Electrification sensitivity, and up to 70% in the High Renewable Gas sensitivity. This significant ongoing role for gaseous fuels reflects the existence of large feedstock and high temperature industrial activities that are difficult or impossible to directly electrify.

A further area of interest in the sensitivities is outcomes in the residential sector, as this has significant implications for the management and transition of both millions of small gas customers and the extensive gas distribution networks that supply them. The Theoretical Efficient Policy scenario found that households primarily used biomethane rather than hydrogen for their gaseous fuel needs, as this avoided significant appliance replacement costs associated with moving to hydrogen. However, this outcome reflects one set of assumptions, and our sensitivity analysis demonstrated that a range of plausible futures exist where hydrogen could play a significant role in the residential sector.

The residential fuel mix in these model runs are shown for comparison in Figure 3.15. These charts illustrate that:

— a range of plausible transition pathways are possible, including significant use of biomethane (Theoretical Efficient Policy scenario), hydrogen (High Hydrogen sensitivity), electrification (High Electrification sensitivity) and natural gas (No Biomethane sensitivity – natural gas use is combined with offsets from 2050 to achieve net zero).
— whereas biomethane is a 'supply-side' transition that does not involve appliance changeover, and so can occur rapidly when the supply-side economics are favourable, a switch to hydrogen tends to occur more gradually to manage the cost of appliance replacement.
— where biomethane is less available or unavailable, natural gas tends to play a role in 2050 (at which time the model requires emissions from this natural gas use to be offset to achieve net zero). Continuing to use natural gas in small volumes in 2050 (and beyond) allows the model to replace household appliances more gradually, reducing and deferring the costs of this process.

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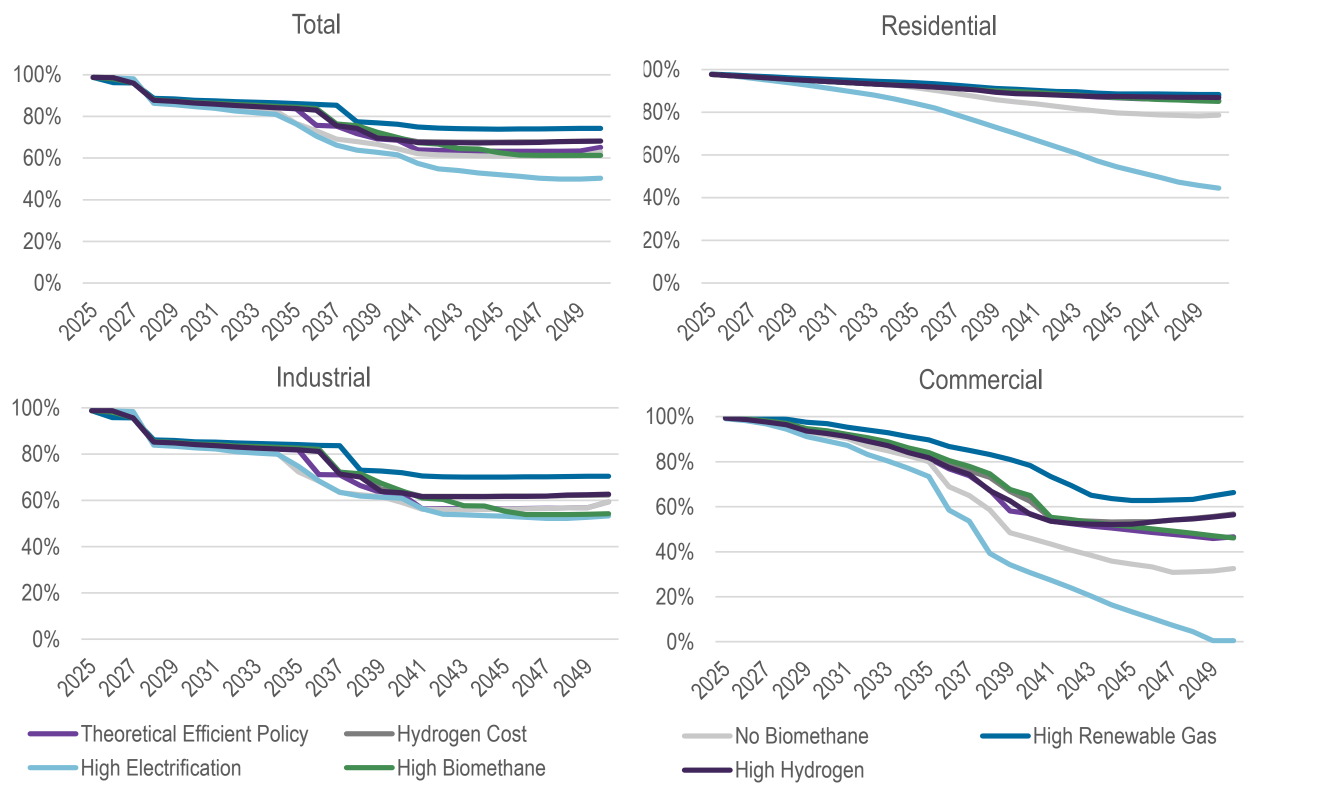
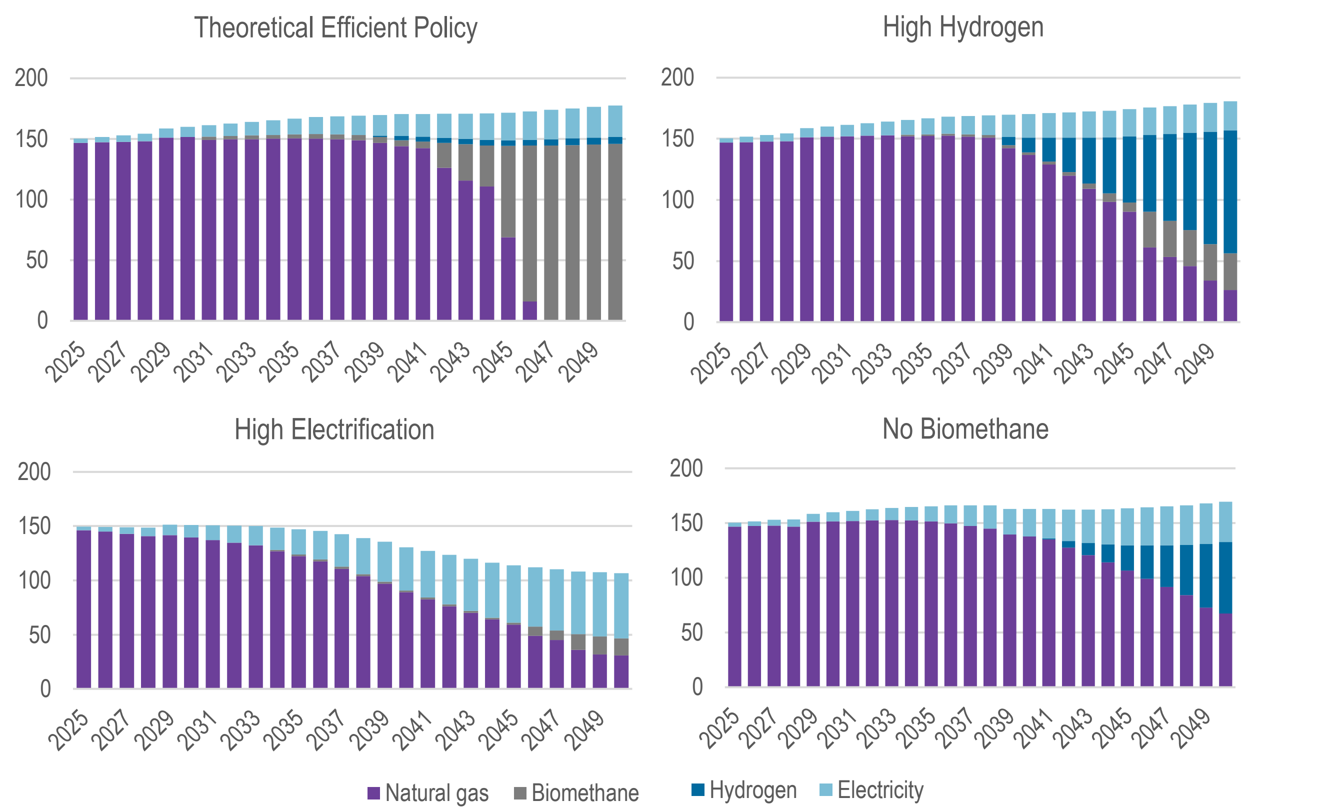
[17] Given the broad-scale of the Gas Transition Model, it is not possible to represent all sub-sectoral activities in great detail (activities modelled are listed in **Table 2.2**). For example, we do not explicitly model activities such as crematoria in the commercial sector, which will be more difficult to electrify than generalised cooking, water heating and space heating activities. Therefore outcomes such as zero gaseous fuel use in the commercial sector should be seen as a stylised high-level finding, that does not fully capture the transition options and challenges of all commercial sub-sectors.

Figure 3.14 Gaseous fuels share (%): Theoretical Efficient Policy scenario and sensitivities, overall and by sector



Source: ACIL Allen Gas Transition Model

Figure 3.15 Residential fuel mix (PJ): Theoretical Efficient Policy scenario and selected sensitivities



Source: ACIL Allen Gas Transition Model

Further details of the six assumption-based sensitivities are provided in Appendix E.

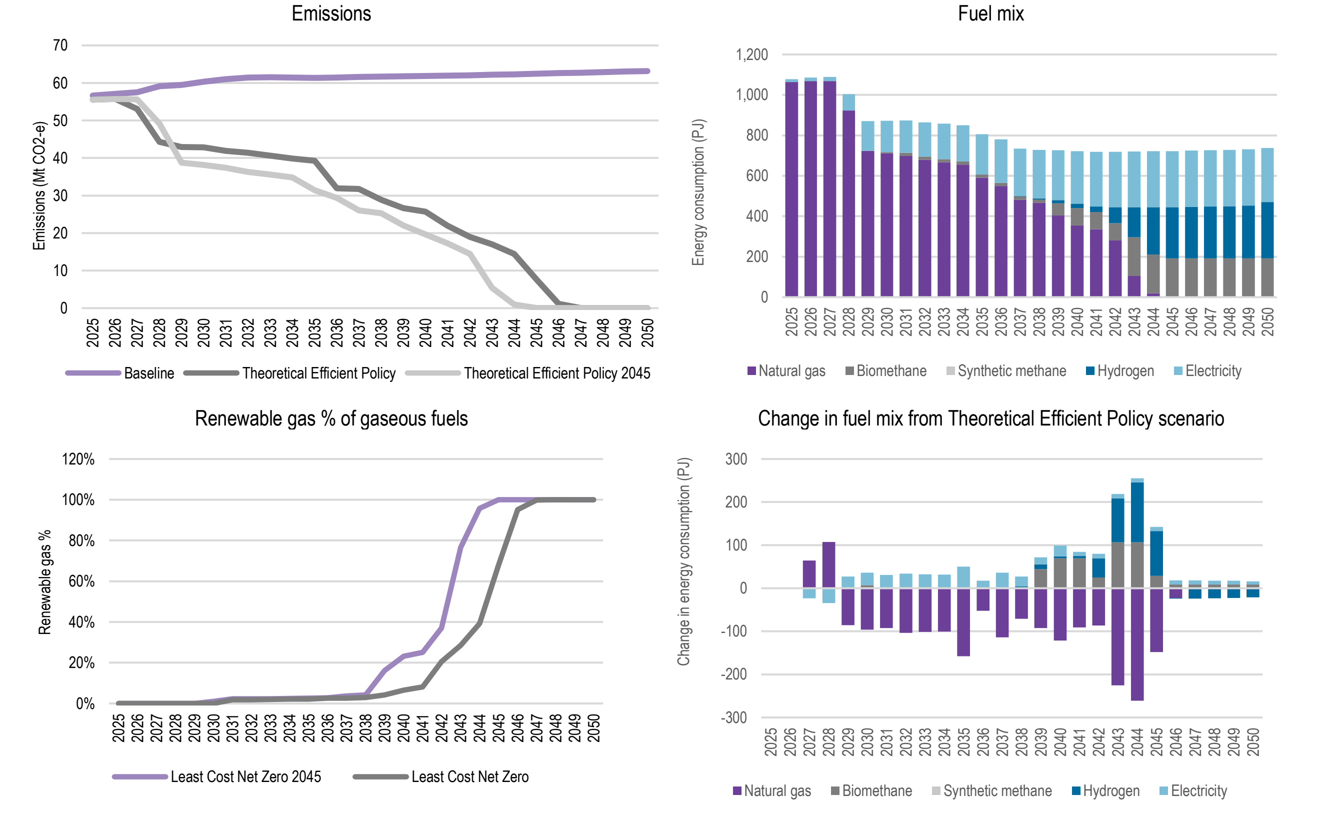
3.2.2 Sensitivity on the effect of achieving net zero by 2045

We also carried out a sensitivity to examine the impact of a more stringent emissions constraint with net zero being required earlier by 2045 rather than 2050. In this sensitivity the 2025 to 2050 emissions budget was adjusted down to 607.7 Mt CO_2-e from 719.4 Mt CO_2-e, reflecting a budget consistent with a straight-line reduction in emissions from projected 2030 levels to net zero in 2045 rather than by 2050.

In the Theoretical Efficient Policy scenario, the development of renewable gases is delayed, reflecting the ongoing reduction in costs the models sees with perfect foresight and the desire to defer capital expenditure as much as possible to reduce its cost in present value terms.

Figure 3.16 presents a snapshot of results from the Theoretical Efficient Policy 2045 sensitivity. The more stringent abatement task is achieved by a small amount of additional annual electrification in the first half of the projection period and a large acceleration of biomethane and hydrogen in the early 2040s. Aggregate resource costs are around $201 billion ($9.2 billion higher with the 2050 target), giving an average abatement cost of $153/tonne CO_2-e ($10/tonne CO_2-e higher than the Theoretical Efficient Policy scenario). The higher per unit abatement cost is unsurprising, given that the faster decarbonisation profile requires the model to replace capital earlier and adopt renewable gases and electrification faster than in the Theoretical Efficient Policy scenario.

Figure 3.16 Theoretical Efficient Policy 2045 sensitivity results summary



Source: ACIL Allen Gas Transition Model

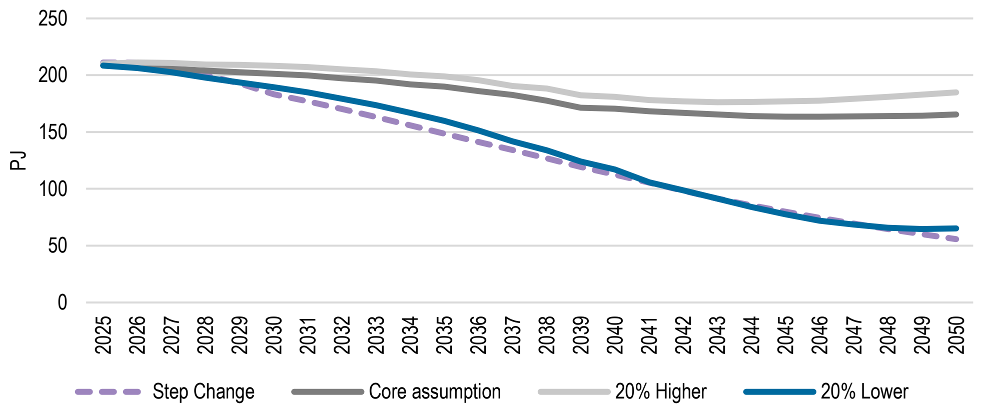
3.2.3 Sensitivity exploring the effect of variations in electrical appliance costs

We undertook further sensitivity analysis on the Theoretical Efficient Policy scenario to understand the effect of variations in capital costs for residential and commercial electrical appliances on outcomes. Sensitivity analysis helps us to understand the effect of these variations as assumptions are inherently uncertain and in practice costs will vary between individual users, resulting in a mix of outcomes across a real-world population of residential and commercial gas users.

Figure 3.17 presents the level of gaseous fuel use across residential and commercial gas users with a variation to electrical appliance costs of 20% higher and lower. We found that pathways are highly sensitive to assumed costs, with results being asymmetrical. A 20% reduction in electrical appliance costs relative to our core assumptions resulting in a level of electrification comparable to the Active Policy + Step Change sensitivity discussed in section 3.1. On the other hand a 20% increase to electrical appliance costs only increased gaseous fuel consumption by around 12% in 2050.

Given this sensitivity, and the likely real-world variations in costs between different users, it is important that policy-makers do not adopt a ‘one-size-fits-all’ approach to residential and commercial decarbonisation, but instead gives users options and flexibility to choose the decarbonisation option that best suits their circumstances.

Figure 3.17 Gaseous fuel consumed by commercial and residential customers: impact of variations to electrical appliance costs



Source: ACIL Allen Gas Transition Model

3.3 Electrify Everything Possible scenario

The Electrify Everything Possible scenario is designed to compare the cost of a heavily electrification-focused approach to achieving net zero to the theoretical optimal outcome in the Theoretical Efficient Policy scenario. The scenario:

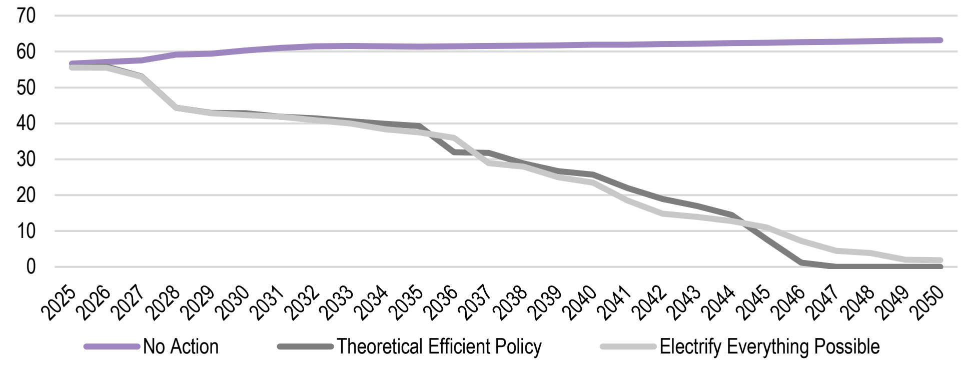
— adopts the same overall (gas sector-wide) emissions budgets as used in the Theoretical Efficient Policy scenario, to ensure a comparable emissions outcome

— adopts the Victorian and ACT restrictions on new residential gas connections

— restricts uptake of renewable gas options other than for activities where electrification is not possible or proven (such as feedstock and some very high temperature processes, to mimic a heavily electrification-focused policy approach to achieving net zero.

Figure 3.18 shows the emissions trajectory under the Electrify Everything Possible scenario relative to the No Action and Theoretical Efficient Policy scenarios. The Electrify Everything Possible scenario tracks closely to the Theoretical Efficient Policy scenario, reflecting the equivalent emissions budget used in both scenarios, with slight divergences in some years.

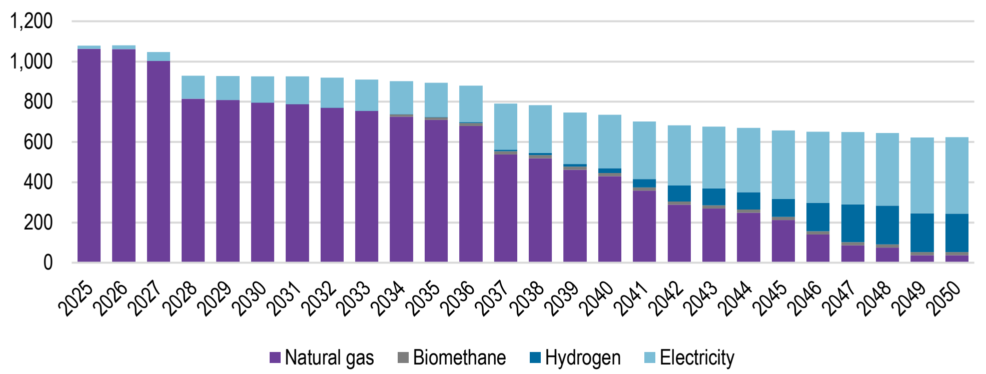
Figure 3.18 Emissions: Electrify Everything Possible scenario relative to Theoretical Efficient Policy and No Action scenarios (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

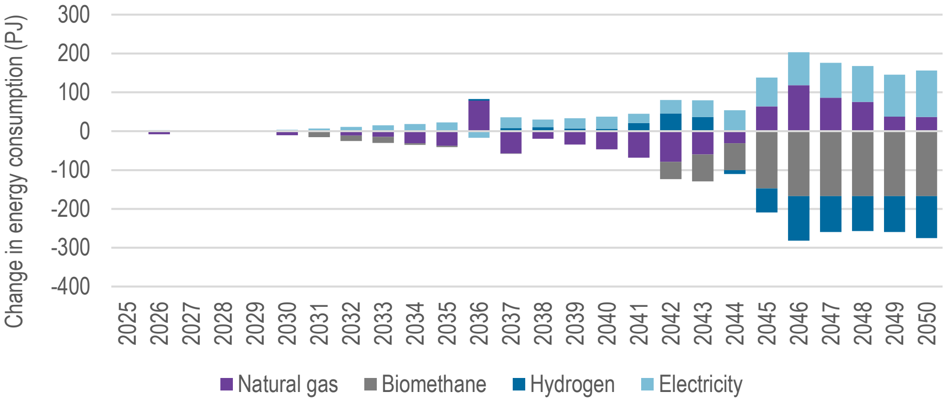
Figure 3.19 shows the mix of fuels used in the Electrify Everything Possible scenario. Reflecting the assumed approach, electricity plays a much greater role in the fuel mix than in the Theoretical Efficient Policy scenario, particularly post-2035, while renewable gases play a smaller role (Figure 3.20). Natural gas use is initially lower in the Electrify Everything Possible scenario, reflecting the earlier adoption of electrification, but is higher in the long-run.

Figure 3.19 Fuel mix: Electrify Everything Possible scenario (PJ)



Source: ACIL Allen Gas Transition Model

Figure 3.20 Fuel mix: change between Electrify Everything Possible scenario and Theoretical Efficient Policy scenario

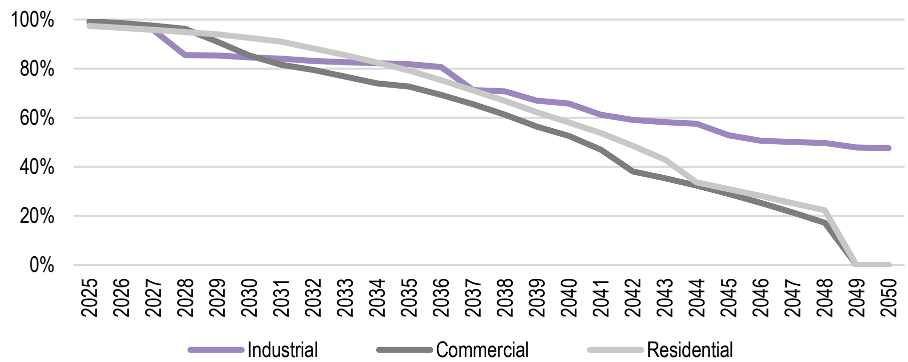


Note: an increase on the y-axis indicates an increase in the use of a fuel in the Electrify Everything Possible scenario relative to the Theoretical Efficient Policy scenario.

Source: ACIL Allen Gas Transition Model

Figure 3.21 demonstrates that in the Electrify Everything Possible scenario the commercial and residential sectors completely electrify by 2050, but gaseous fuels continue to play a significant role in the industrial sector (providing about 50% of energy). This reflects the existince of hard-to-electrify high temperature and feedstock processes in the industrial sector. For the purpose of the modelling we have assumed that renewable gas supply to industry is viable irrespective of whether the residential and commercial sectors electrify, but in practice a decline in demand for gaseous fuels in one sector may affect the viability of supplying other sectors (for example, by reducing the viability of gas networks serving a mix of customers).

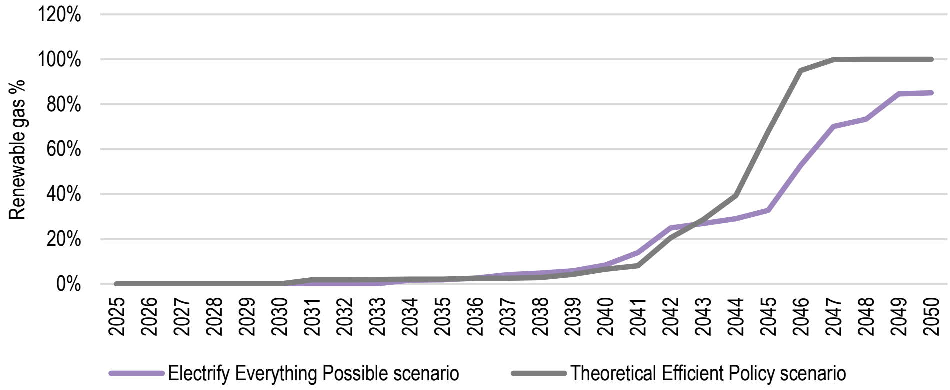
Figure 3.21 Electrify Everything Possible scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Figure 3.22 shows that the Electrify Everything Possible scenario has a significantly lower share of renewable gas than the Theoretical Efficient Policy scenario, reflecting the higher amount of electrification in the Electrify Everything Possible scenario based on assumed electrification policy.

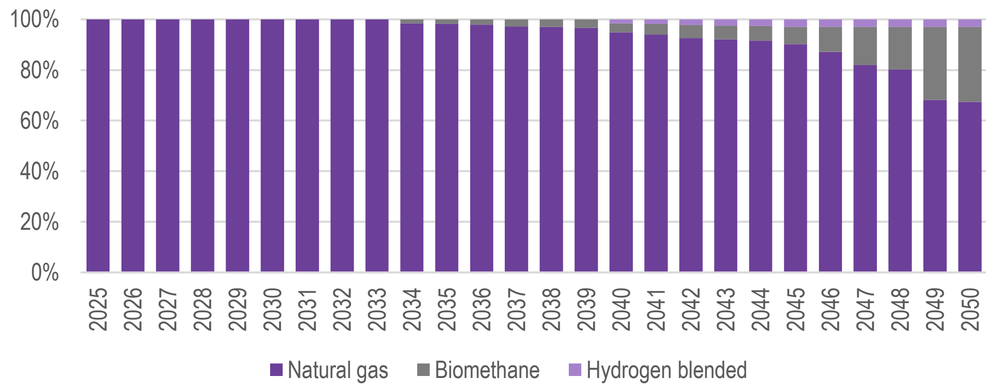
Figure 3.22 Renewable gas percentage of gaseous fuels: Electrify Everything Possible scenario and Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

Figure 3.23 shows the composition of the blended gas stream (excluding dedicated hydrogen supply), and shows how the focus on electrification in this scenario results in a slow change in the composition of blended gas, with biomethane and blended hydrogen remaining a minority share up to and including 2050.

Figure 3.23 Composition of blended gas stream, by gas type: Electrify Everything Possible scenario



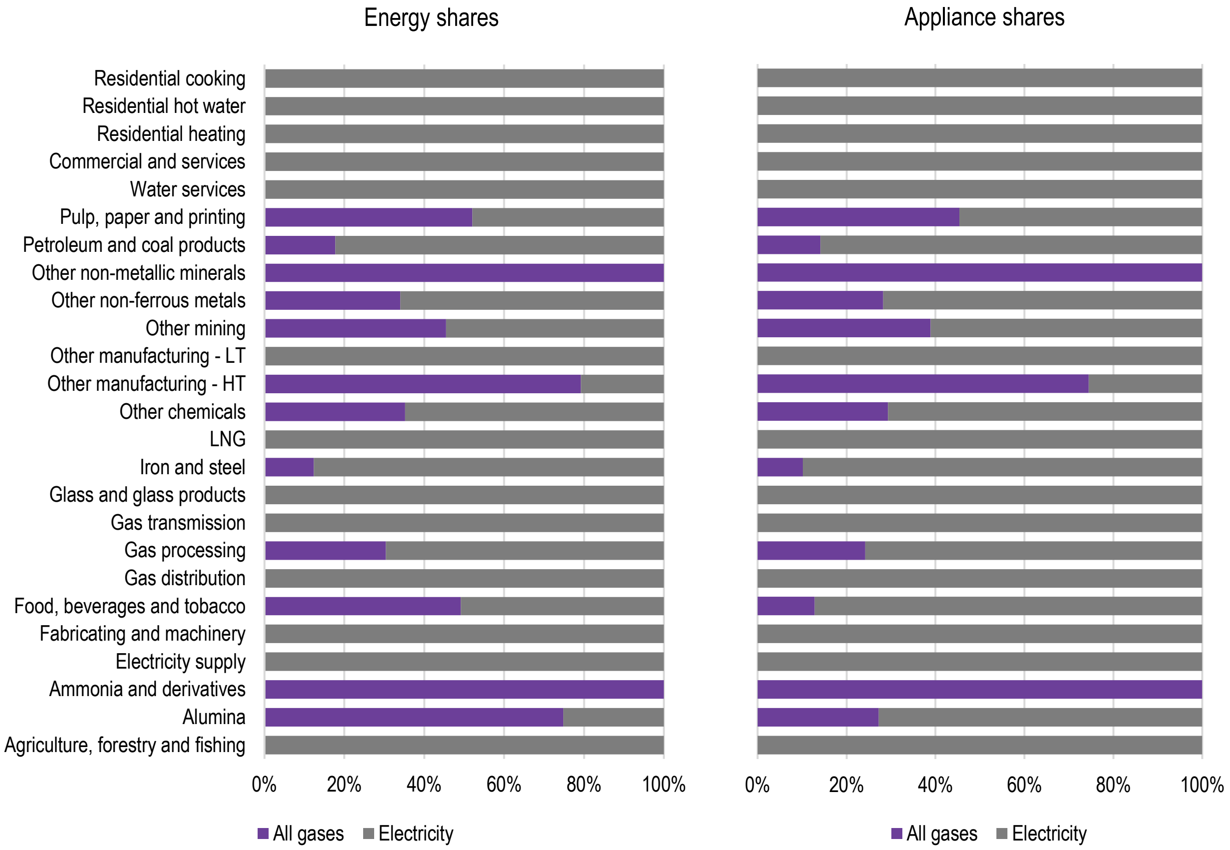
Source: ACIL Allen Gas Transition Model

Figure 3.24 provides a breakdown of fuel use and appliance types by sector on a national level in 2050. Compared to the Theoretical Efficient Policy scenario (Figure 3.11), the Electrify Everything Possible scenario has a much higher degree of electrification, with 120 PJ more electricity use and 239 PJ less gaseous fuel use in 2050 than in the Theoretical Efficient Policy scenario. Gaseous fuel use in the Electrify Everything Possible scenario is concentrated in the alumina, ammonia and non-metallic minerals sectors reflecting the use of gaseous fuels for feedstock and high-temperature calcining. Small volumes of gaseous fuels are use in other sectors, which reflect appliances continuing to use natural gas because electrification of those appliances is not necessary to achieve the overall emissions budget.[18] As noted in section 3.2, detailed sectoral level results as presented in Figure 3.24 should be treated with a degree of caution as each sector is represented by a small number of generalised activity types, and in practice users in some sectors

[18] If we forced the model to electrify these appliances we would over-achieve the total emissions budget, making comparisons across scenarios harder.

will have a more diverse range of energy needs, and face different drivers and barriers when decarbonising.

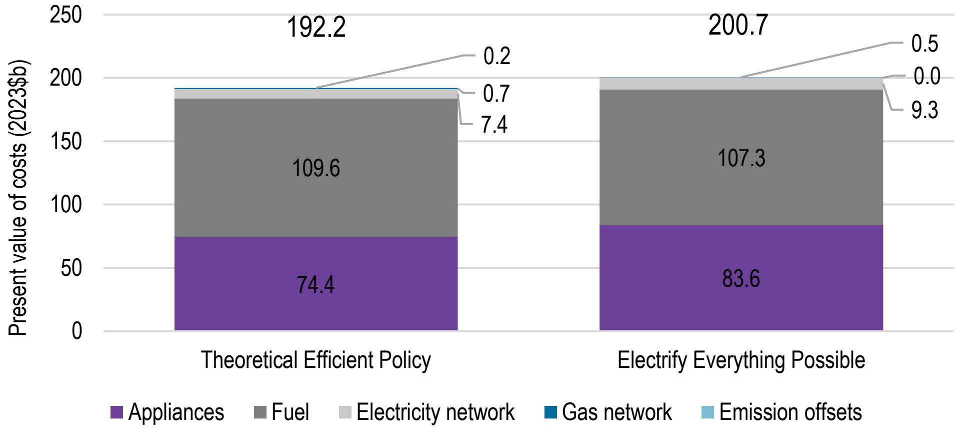
Figure 3.24 Energy and appliance shares by sector and fuel type in 2050: Electrify Everything Possible scenario



Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.25 compares the present value of costs in the Electrify Everything Possible scenario to those in the Theoretical Efficient Policy scenario. Costs are higher in the Electrify Everything Possible scenario at almost $201 billion, compared to $192 billion in the Theoretical Efficient Policy scenario. The higher overall cost of the Electrify Everything Possible scenario translates to a higher average cost of abatement – around $165/tonne CO_2-e compared to the $143/tonne CO_2-e achieved in the Theoretical Efficient Policy scenario.

Figure 3.25 Present value of costs by category, 2025 to 2060: Electrify Everything Possible scenario compared to Theoretical Efficient Policy scenario



Note: present value calculated using a 7% discount rate
Source: ACIL Allen Gas Transition Model

The higher costs in the Electrify Everything Possible scenario relative to the Theoretical Efficient Policy scenario are not surprising given that the Electrify Everything Possible scenario requires users in some sectors to reduce emissions through electrification where renewable gases provide a lower-cost option. However, this result does provide some policy insights:

— Policies that force one approach over another will tend to increase costs relative to more broadly-based policies that allow different sectors and users to identify the best fuel and appliance mix for decarbonising their activities. In this case, a significant electrification requirement increases costs relative to a more neutral policy that gives these users freedom to choose between renewable gas and electrification.

— A complete electrification solution is unlikely to be economically optimal, and renewables gases are, if supported alongside electrification through policy settings, likely to play a key role in both the short- and long-term.

3.4 Optimal RGT scenario

The Optimal RGT scenario is designed to achieve a gradually increasing RGT that broadly reflects the level of renewable gas achieved in the Theoretical Efficient Policy scenario, but which slightly accelerates the uptake of renewable gases to reflect a more realistic ramp-up of the industry. The Optimal RGT trajectory modelled requires renewable gases to reach the following shares of total gaseous fuel consumption:

— 3% by 2030

— 25% by 2040

— 95% by 2050.

While the Theoretical Efficient Policy scenario defers renewable gas investment as late as possible, and primarily develops this supply source from around 2039, this pathway is unlikely to be practically feasible or desirable for several reasons:

— It takes time to develop industry capability and skills to deliver projects, and the renewable gas industry is unlikely to be able to ramp as fast as is modelled in the Theoretical Efficient Policy scenario without earlier investment to gradually build industry capacity.

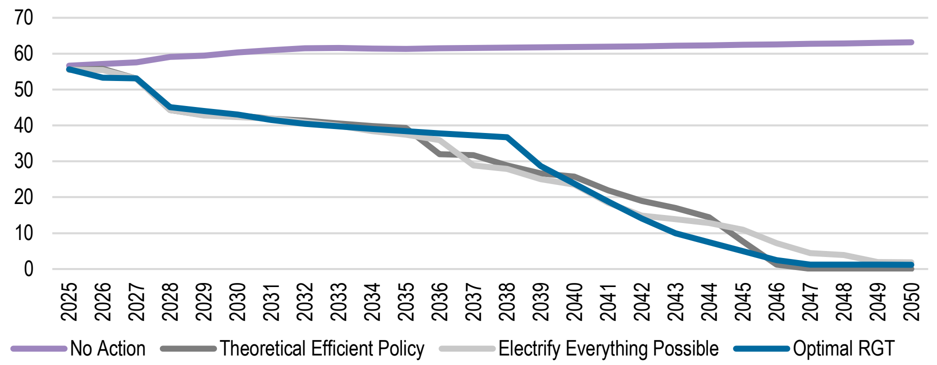
— Leaving renewable gas investment to the latest 'optimal' point in time is a risky strategy in the real world given the risk that projects will be delayed or supply chain constraints may not support extremely rapid ramping of capacity. For example, these real-world constraints are evident in some of the challenges faced by the electricity industry in rapidly ramping renewable generation capacity.

— Demonstrating the technical feasibility and real-world economics of renewable gas will be important to build confidence of gas users to choose this decarbonisation option. While electricity supply side decarbonisation has been demonstrated as a feasible pathway, delaying significant renewable gas development until the late 2030s could discourage some users from adopting this pathway, even if it is the lowest-cost pathway for them in the long-term – for example due to a desire to achieve interim emissions reduction targets.

Noting that these practical points cannot be fully captured within an optimisation model, which chooses a least cost pathway given a known future, the Optimal RGT scenario will necessarily be higher cost than the Theoretical Efficient Policy scenario. However, it demonstrates the potential increase in cost needed to de-risk the adoption of renewable gas through bringing forward investment and developing the industry. Given the risks noted above, this cost could be considered as a form of insurance, that gives policy-makers and gas users greater confidence that this pathway will be available in time to achieve their decarbonisation objectives.

As with the Electrify Everything Possible scenario, the Optimal RGT scenario adopts the same overall (gas sector-wide) emissions budgets as used in the Theoretical Efficient Policy scenario to ensure a comparable emissions outcome. The emissions trajectory varies slightly between the scenarios, with the Optimal RGT delaying decarbonisation slightly during the late 2030s and then reducing emissions more rapidly during the 2040s to achieve the same budget.

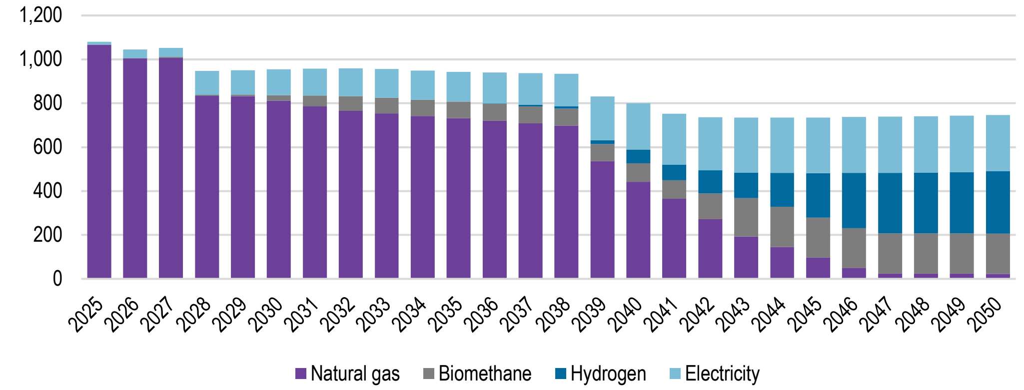
Figure 3.26 Emissions: Optimal RGT scenario relative to No Action, Theoretical Efficient Policy and Electrify Everything Possible scenarios (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

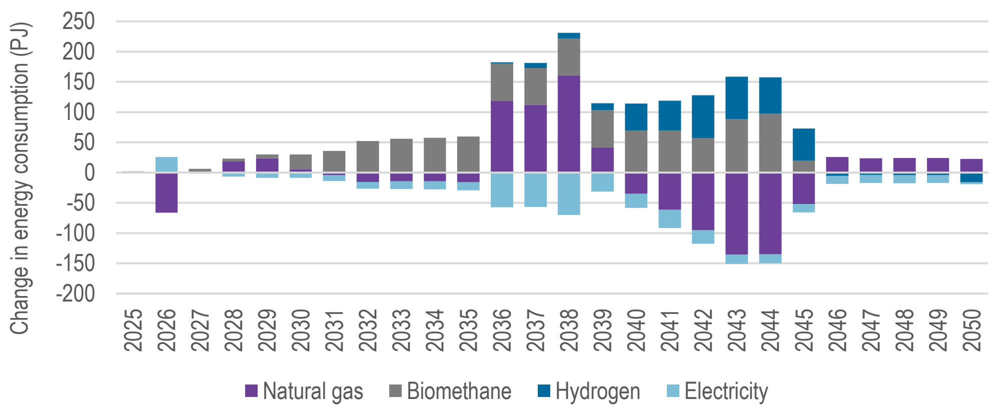
Figure 3.27 shows the mix of fuels used in the Optimal RGT scenario. Reflecting the assumptions of a formal RGT policy to bring forward renewable gas investment, biomethane production is higher than the Theoretical Efficient Policy scenario, particularly during the 2030s, and hydrogen production is higher, particularly during the 2040s (Figure 3.28). Early hydrogen development is also increased during the 2030s, albeit in smaller volumes than biomethane.

Figure 3.27 Fuel mix: Optimal RGT scenario (PJ)



Source: ACIL Allen Gas Transition Model

Figure 3.28 Fuel mix: change between Optimal RGT scenario and Theoretical Efficient Policy scenario

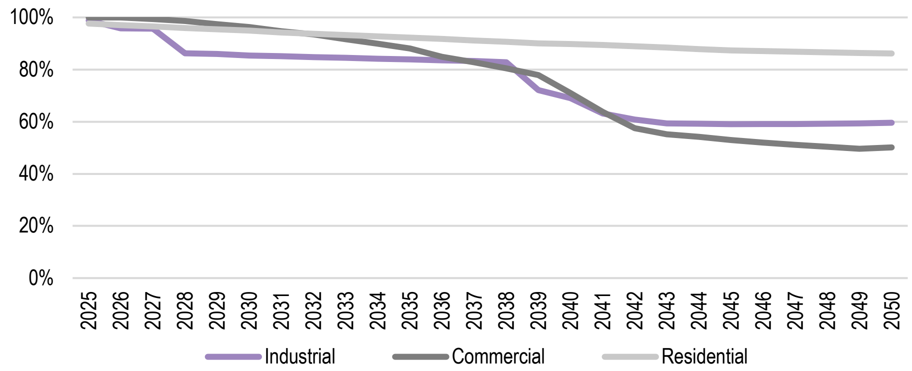


Note: an increase on the y-axis indicates an increase in the use of a fuel in the Optimal RGT scenario relative to the Theoretical Efficient Policy scenario.

Source: ACIL Allen Gas Transition Model

Figure 3.29 shows that gaseous fuels and electricity both play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector.

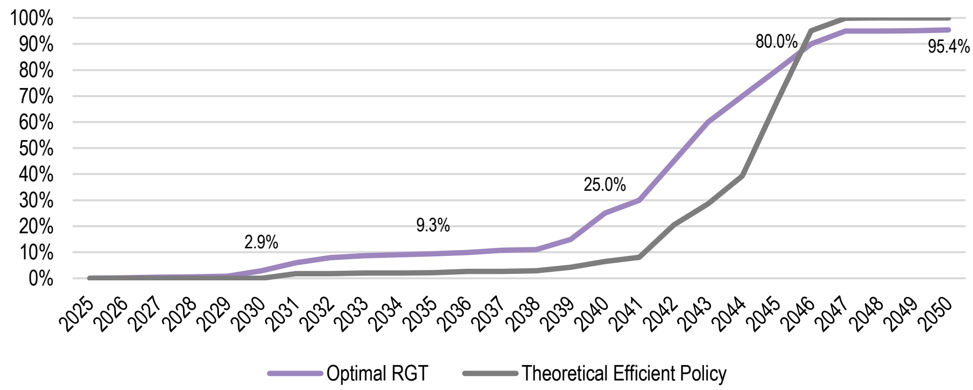
Figure 3.29 Optimal RGT scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Figure 3.30 shows that the Optimal RGT scenario achieves a higher share of renewable gas than the Theoretical Efficient Policy scenario, reflecting the assumed design of the RGT policy to bring forward renewable gas development.

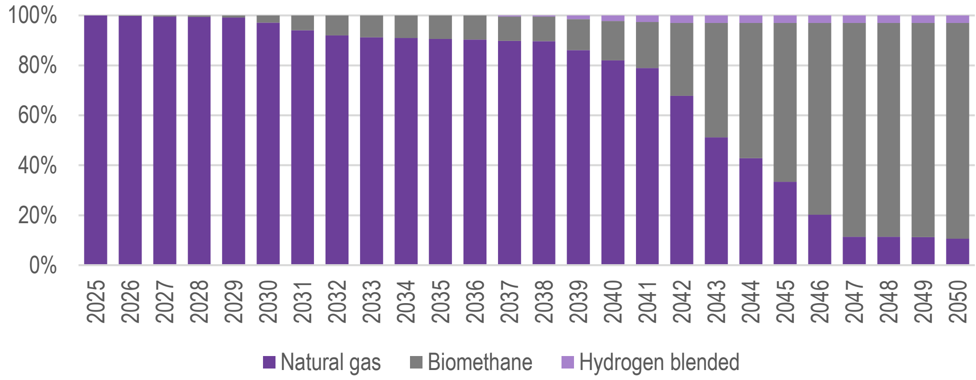
Figure 3.30 Renewable gas share of gaseous fuels: Optimal RGT scenario and Theoretical Efficient Policy scenario



Source: ACIL Allen Gas Transition Model

Figure 3.36 shows the composition of the blended gas stream (excluding dedicated hydrogen supply), and shows how the development of renewable gases through an RGT sees biomethane become about 10% of the blended gas stream by the mid-2030s, and the majority of that stream by 2044.

Figure 3.31 Composition of blended gas stream, by gas type: Optimal RGT scenario



Source: ACIL Allen Gas Transition Model

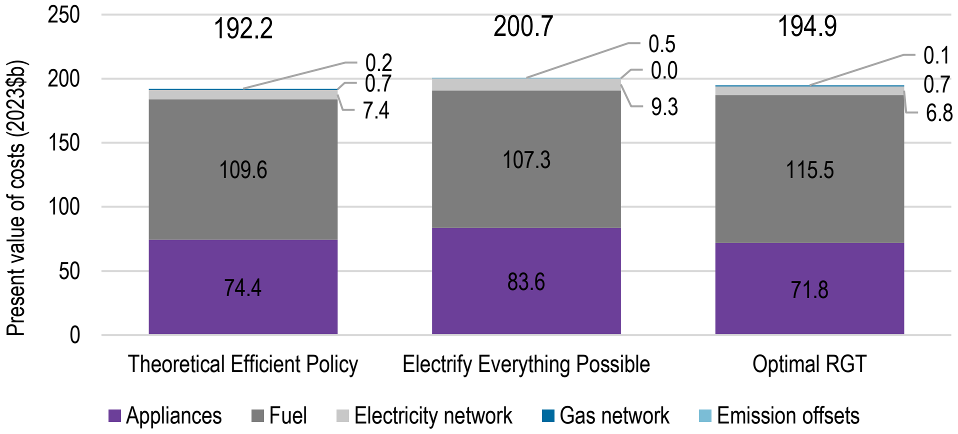
Figure 3.32 provides a breakdown of fuel use and appliance types by sector on a national level in 2050. Compared to the Theoretical Efficient Policy scenario (Figure 3.11), fuel mixes are very similar, with slightly increased use of renewable gases (reflecting the RGT policy) and, consequently, slightly reduced electrification. As noted in section 3.2, detailed sectoral level results as presented in Figure 3.24 should be treated with a degree of caution as each sector is represented by a small number of generalised activity types, and in practice users in some sectors will have a more diverse range of energy needs, and face different drivers and barriers when decarbonising.

Figure 3.32 Energy and appliance shares by sector and fuel type in 2050: Optimal RGT scenario

Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.33 compares the present value of costs in the Optimal RGT scenario to those in the Theoretical Efficient Policy and Electrify Everything Possible scenarios. The Optimal RGT scenario is slightly more expensive than the Theoretical Efficient Policy scenario, costing $194.9 billion compared to $192.2 billion. However, the Optimal RGT scenario is lower cost than the Electrify Everything Possible scenario, reflecting the more balanced use of both renewable gas and electrification under an RGT policy. Adopting this approach rather than an ‘electrify everything’ approach reduces costs by almost $6 billion in present value terms and reduces the average cost of abatement from $165/tonne CO_2-e to $150/tonne CO_2-e.

Figure 3.33 Present value of costs by category, 2025 to 2060: Theoretical Efficient Policy, Electrify Everything Possible and Optimal RGT scenarios



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

The higher costs in the Optimal RGT scenario relative to the Theoretical Efficient Policy scenario are not surprising given that the Theoretical Efficient Policy scenario is optimised to achieve emissions reductions at the lowest cost given the input assumptions. However, as noted above, the Optimal RGT reflects a real-world policy approach to steadily build renewable gas industry capacity through the 2020s and 2030s, to enable it to play its very significant long-term decarbonisation role. The additional $2.6 billion in costs relative to the Theoretical Efficient Policy scenario (a 1.4% increase) represents a small investment to de-risk the development of this option and support the gas sector's long-term transition.

3.5 Accelerated RGT scenario

The Accelerated RGT scenario is designed to achieve faster growth in renewable gases than is achieved under the Optimal RGT or Theoretical Efficient Policy scenarios. This scenario broadly reflects a situation where policy-makers choose to prioritise and accelerate development in renewable gases, potentially due to policy decisions to accelerate national decarbonisation (for example, as part of determining Australia's 2035 Nationally Determined Contributions under the Paris Agreement), a recognition of the importance of these options to achieve long-term decarbonisation, a strategic recognition of the opportunities for renewable gases to underpin emerging export industries such as green hydrogen, green ammonia or green iron, or difficulties in achieving fast and cost-effective abatement from other sectors.

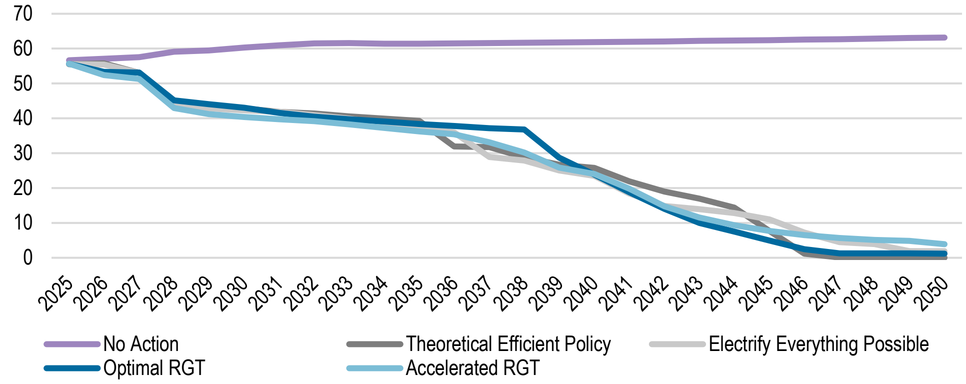
The Accelerated RGT trajectory modelled requires renewable gases to reach the following shares of total gaseous fuel consumption:

— 10% by 2030
— 32% by 2040
— 84% by 2050.

As with the Optimal RGT scenario, accelerating renewable gas uptake relative to the Theoretical Efficient Policy scenario will increase costs within the framework of a perfect foresight optimisation model, but has other real-world benefits such as early development of skills and capabilities, reducing the risk that a rapid ramp-up in renewable gas capacity will be hampered by supply chain or other logistical constraints, and in building users' confidence in the viability of renewable gas as a decarbonisation option.

Unlike the other policy scenarios, the Accelerated RGT scenario is not required to comply with an overall (gas sector-wide) emissions budget, but the ambition of the RGT itself is sufficient to ensure that emissions are significantly lower in this scenario than in the other policy scenarios (Figure 3.35). While the other policy scenarios limit net emissions to 719 Mt CO_2-e over the period from 2025 to 2050, the Accelerated RGT scenario results in 709 Mt CO_2-e over the same period.

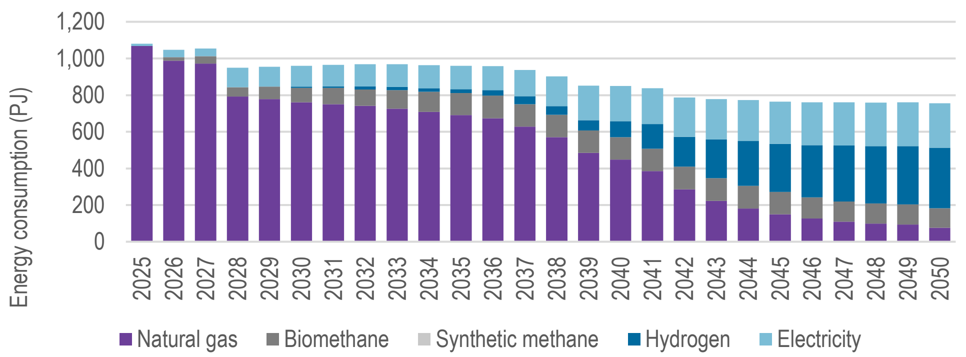
Figure 3.34 Gas sector emissions, by scenario (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

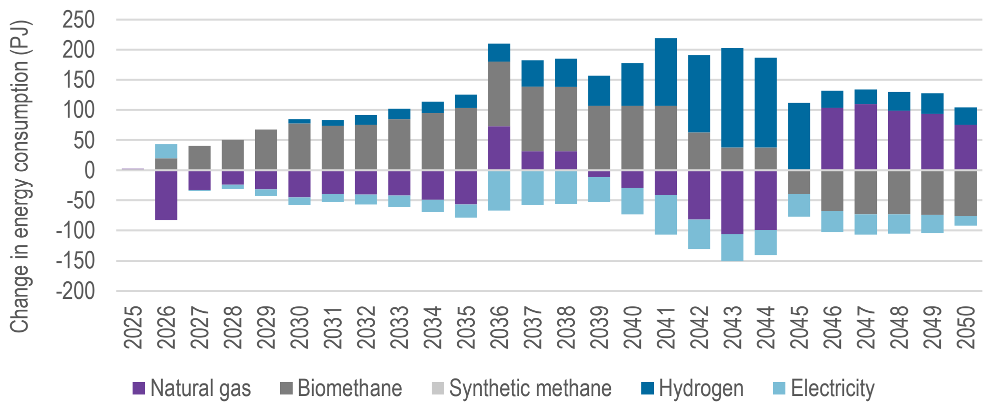
Figure 3.35 shows the mix of fuels used in the Accelerated RGT scenario, while Figure 3.36 shows the significant acceleration of renewable gas production (both biomethane and hydrogen) under the Accelerated RGT relative to the Theoretical Efficient Policy scenario prior to 2045. This acceleration can also be seen by comparing the renewable gas share achieved across the policy scenarios (Figure 3.37). The long-term level of renewable gas is actually slightly lower than under the Theoretical Efficient Policy and Optimal RGT scenarios, which reflects the fact that the earlier uptake of renewable gas means less renewable gas is needed in the long-run to achieve a comparable overall emissions level.

Figure 3.35 Fuel mix: Accelerated RGT scenario (PJ)



Source: ACIL Allen Gas Transition Model

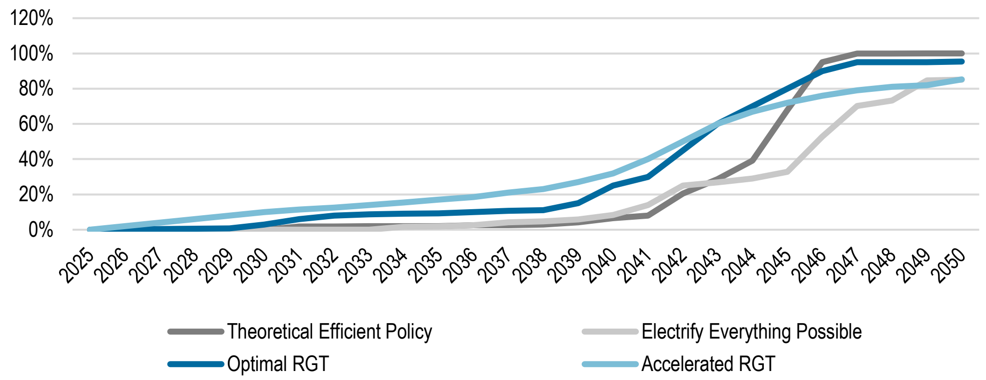
Figure 3.36 Fuel mix: change between Accelerated RGT scenario and Theoretical Efficient Policy scenario



Note: an increase on the y-axis indicates an increase in the use of a fuel in the Accelerated RGT scenario relative to the Theoretical Efficient Policy scenario.

Source: ACIL Allen Gas Transition Model

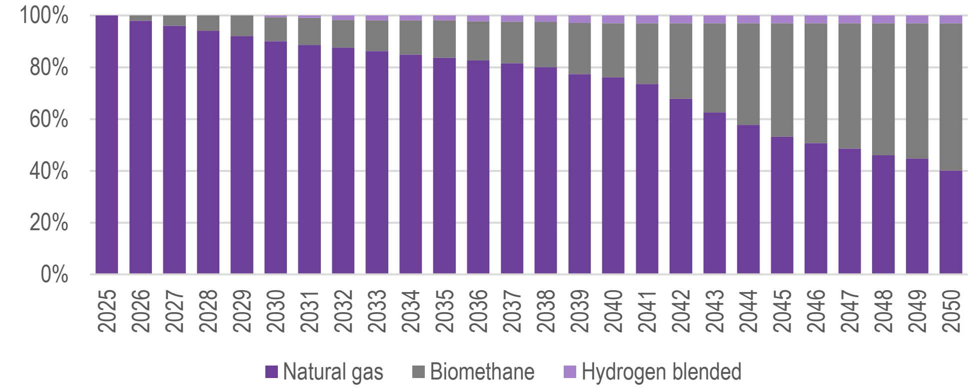
Figure 3.37 Renewable gas share of gaseous fuels, by policy scenario



Source: ACIL Allen Gas Transition Model

Figure 3.38 shows the composition of the blended gas stream (excluding dedicated hydrogen supply), and shows how the accelerated RGT builds the proportion of biomethane in the blended gas stream steadily, reaching about 10% in 2031 and 20% by 2039, and continues growing through the 2040s.

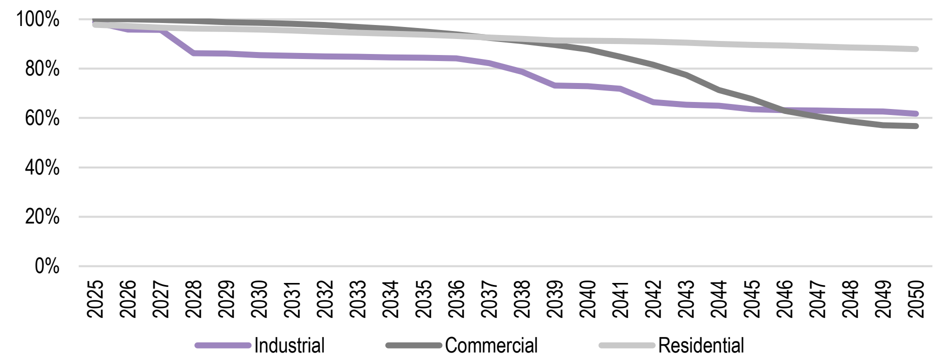
Figure 3.38 Composition of blended gas stream, by gas type: Accelerated RGT scenario



Source: ACIL Allen Gas Transition Model

Figure 3.39 shows that gaseous fuels and electricity both play important roles across each of the industrial, commercial and residential sectors, with gaseous fuels playing a particularly large role in the residential sector.

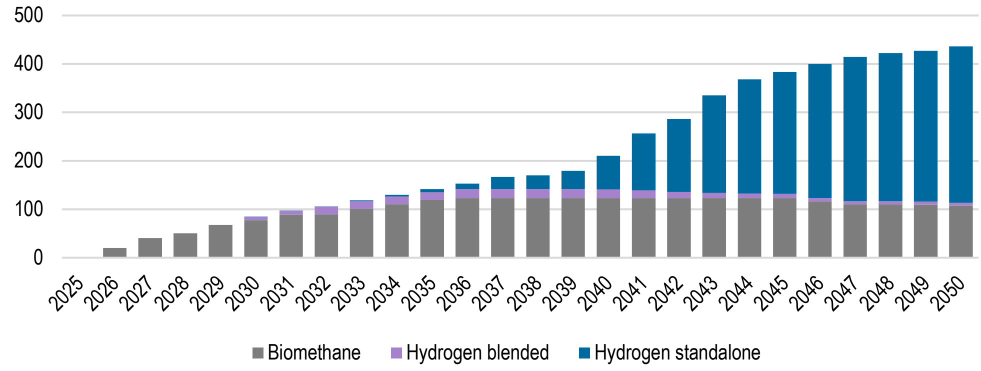
Figure 3.39 Accelerated RGT scenario gaseous fuel share by end use sector



Source: ACIL Allen Gas Transition Model

Development of renewable gas is initially focussed on the lower cost biomethane under the Accelerated RGT scenario as shown in Figure 3.40. Hydrogen blending also plays a role is relatively limited due to its blending constraint (3% by energy). Standalone hydrogen is developed rapidly in this scenario with volumes ramping up in the early 2030's to reach 163 PJ by 2042.

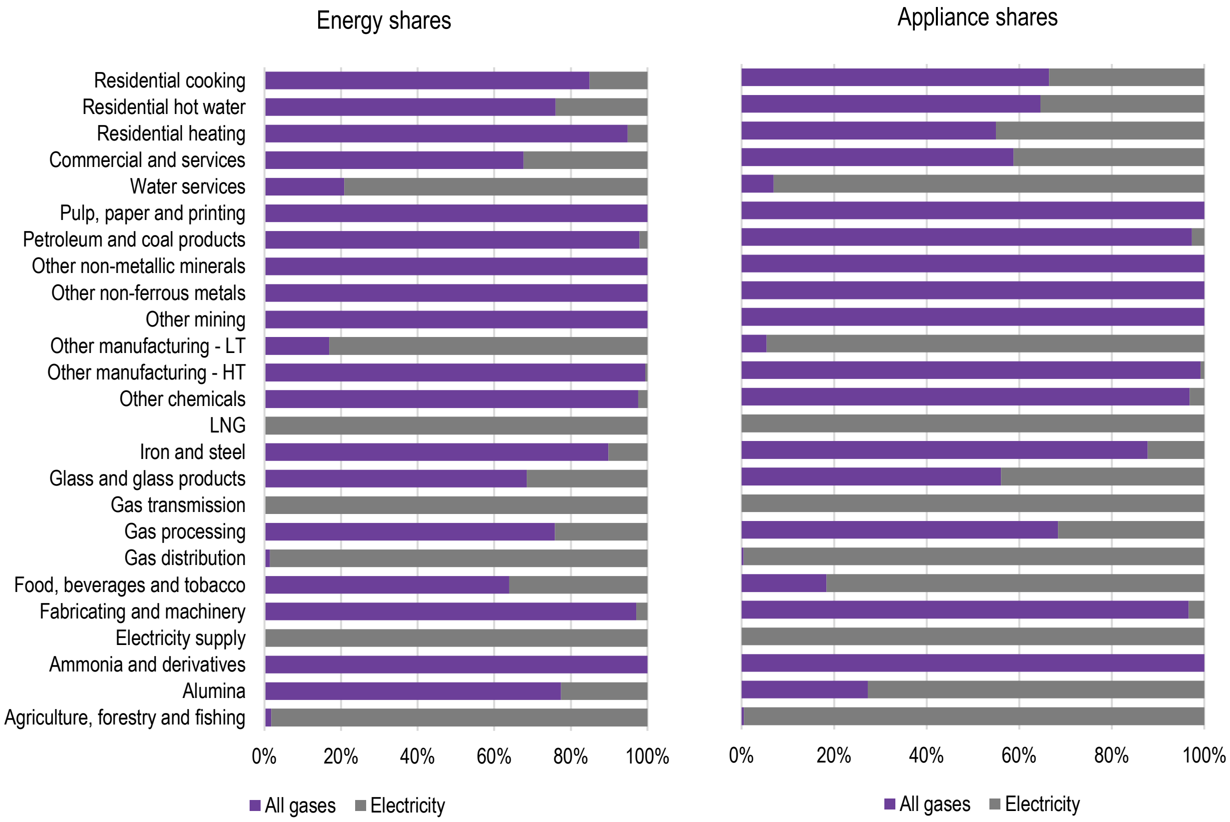
Figure 3.40 Renewable gas developed: Accelerated RGT scenario



Source: ACIL Allen Gas Transition Model

Figure 3.41 provides a breakdown of fuel use and appliance types by sector on a national level in 2050. Compared to the Theoretical Efficient Policy scenario (Figure 3.11), fuel mixes are similar, with a slight increase in the overall use of gaseous fuels and a slight decrease in the amount of electrification.

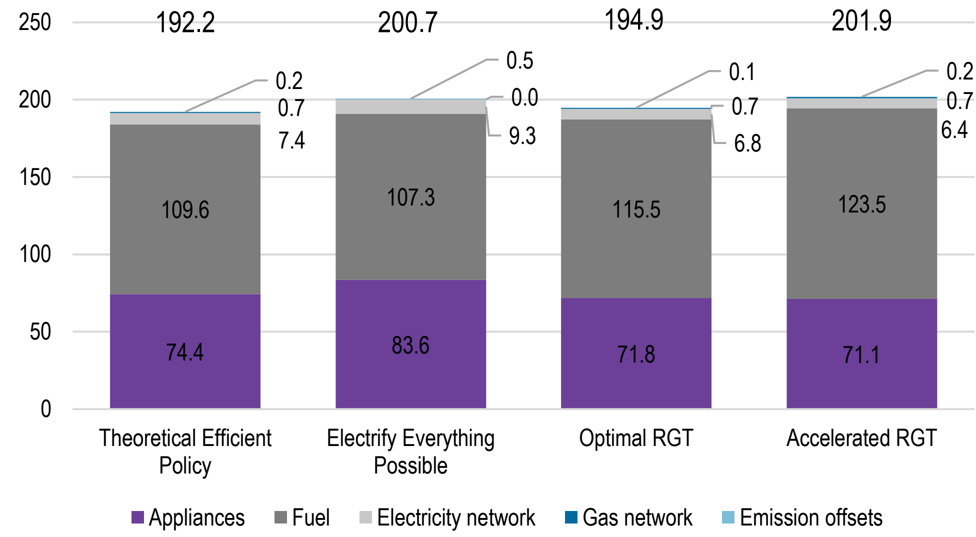
Figure 3.41 Energy and appliance shares by sector and fuel type in 2050: Accelerated RGT scenario



Notes: Electricity supply is for LNG on-site electricity generation only. LT = low temperature. HT = high temperature. LNG is LNG compression only.
Source: ACIL Allen Gas Transition Model

Figure 3.42 compares the present value of costs in the Accelerated RGT scenario to the other policy scenarios. The accelerated development of renewable gas increases costs relative to the Theoretical Efficient Policy and Optimal RGT scenarios. The scenario has slightly higher total cost than the Electrify Everything Possible scenario, but when converted to a cost per unit of abatement to account for the slightly lower emissions in that scenario, the Accelerated RGT achieves slightly lower per unit abatement costs than the Electrify Everything Possible scenario – \$164/tonne CO_2-e compared to \$165/tonne CO_2-e. This indicates that adopting an accelerated emissions reduction approach through an RGT, that includes both electrification and renewable gas, can reduce emissions faster and at a comparable cost than an electrification-focused approach.

Figure 3.42 Present value of costs by category, 2025 to 2060, by policy scenario (\$b)



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Gas Transition Model

3.5.1 RGT trajectory sensitivities

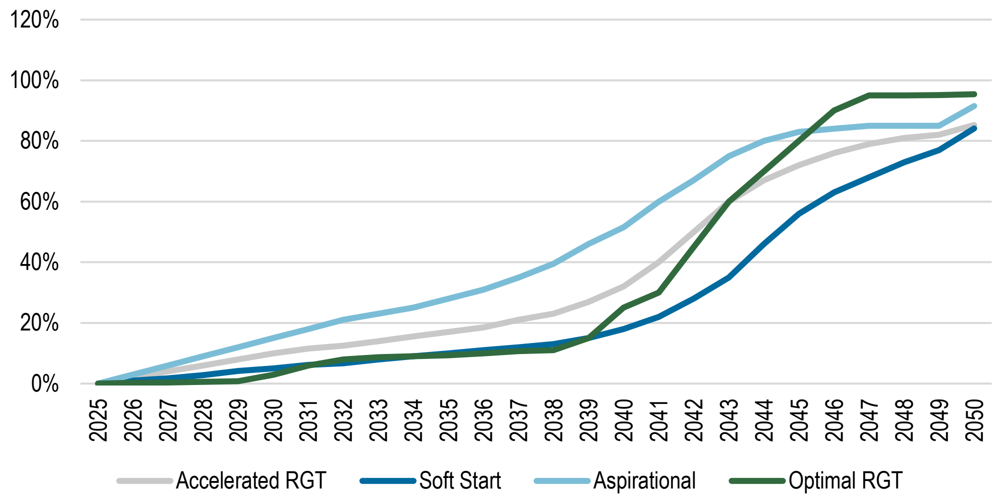
Comparing the Optimal RGT and Accelerated RGT scenarios demonstrates that accelerated renewable gas uptake through higher RGTs can increase abatement, albeit at higher average unit cost. To further explore the effect of variations in the speed of renewable gas uptake we explored two further sensitivities where we set the following minimum renewable gas constraints within the GTM to establish the following RGT uptake trajectories:

— A 'Soft Start' trajectory which utilises a diffusion of innovation S-Curve from 2025 to 2060, starting at 0% renewable gas in 2025 and ending at 85% in 2055

— An 'Aspirational' trajectory which increases linearly from zero 0 to 15% renewable gas in 2030 then utilises a diffusion of innovation S-Curve ending at 85% in 2047.

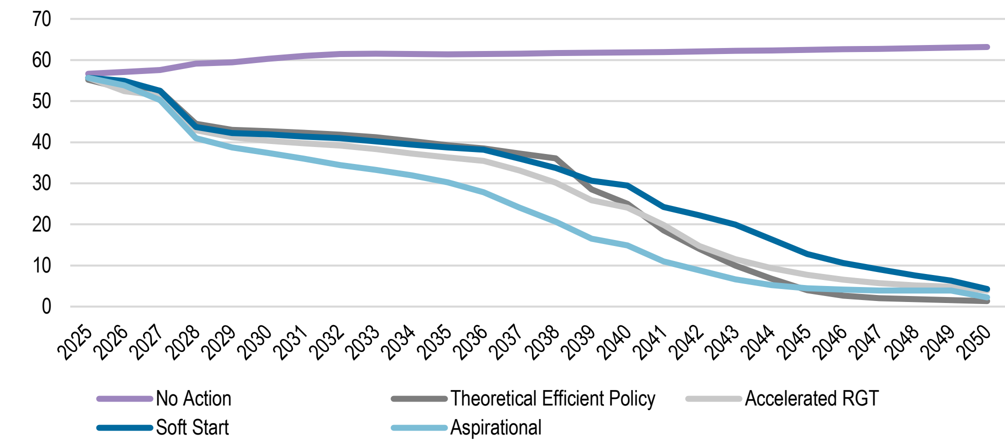
Figure 3.43 compares the targets under the 'Soft Start' and 'Aspirational' trajectories relative to the Optimal RGT and Accelerated RGT scenarios, and Figure 3.44 compares the emissions outcomes under these scenarios and sensitivities. As expected, the Aspirational trajectory reduces emissions faster than even the Accelerated RGT, whiles the Soft Start trajectory has higher emissions.

Figure 3.43 Renewable gas share of gaseous fuels, RGT sensitivities: Accelerated, Soft and Aspirational targets compared with Optimal RGT



Source: ACIL Allen Gas Transition Model

Figure 3.44 Emission outcomes under the RGT sensitivities (Mt CO_2-e)



Source: ACIL Allen Gas Transition Model

Whole-of-economy modelling 4

This chapter provides an overview of the approach used to model the broader economic impact of the gas transition scenarios using computable general equilibrium (CGE) modelling and presents the projected impacts.

4.1 Introduction

To provide information on the broader economic impacts on the Australian economy potentially arising from the large structural changes involved in achieving the gas transitions, ACIL Allen has undertaken CGE modelling using our *Tasman Global* model. It is a multi-sector dynamic model of the Australian and world economy that has been used for many similar modelling projects. An overview of the model is provided in Appendix F.

Transitioning today's natural gas using sectors to net zero emissions will require a wide range of capital and operating expenses across the economy. These include capital expenditure by businesses and households to replace appliances, and capital expenditure by energy supplying sectors to provide electricity or renewable gases to end-use sectors.

The estimated capital and operating expenses underlying each scenario along were used to inform the Tasman Global No Action and policy scenarios. The differences between the economic projections of the No Action and the various policy scenarios provide a forecast of the total economic impacts of each policy scenario.

CGE models produce a wide variety of economic metrics. The metrics reported in this case include:

— Real economic output (as measured by real Gross State Product (GSP) or Gross Domestic Product (GDP)) is defined as the sum of value added by all producers who are within the region/state, plus any product taxes (minus subsidies) not included in output. A positive deviation (i.e. increase) of real economic output from the No Action scenario implies that the proposed transition scenario will enable the economy to produce more real goods and services potentially available for consumption.

— Real income: In most CGE models, such as Tasman Global, the change in real income is a measure of the change in economic welfare of the residents of the region, state or country. The change in real income is equal to the change in real economic output plus the change in net foreign income transfers plus the change in terms of trade. In contrast to measures such as real economic output, real income accounts for any impacts of foreign ownership and debt repayments, as well as changes in the purchasing power of residents as a result of a project or policy.

— Employment and real wages impacts, with employment measured in terms of full-time equivalent (FTE) jobs.

4.1.1 Framework of analysis

The macroeconomic impacts of a policy, project or other activity can be estimated using a variety of economic analysis tools. The most common methods utilised are input-output (I-O) multiplier analysis and CGE modelling. The selection of the right tool is critical to the accuracy of the estimated impacts and depends upon the characteristics of the policy or project. Sometimes more than one tool may be required to provide a full picture of economic consequences.

By their nature, I-O multipliers and CGE models focus on 'market impacts' across the economy (that is, impacts on activities with observed market prices). Analysis of various 'non-market impacts', such as property right infringements, potential loss of biodiversity, changes in air quality or greenhouse gas emissions, social justice implications and so forth may also be relevant in assessing the full implications of a project or policy, but are not captured within I-O multipliers and CGE models. Such effects can be incorporated into a traditional CBA.

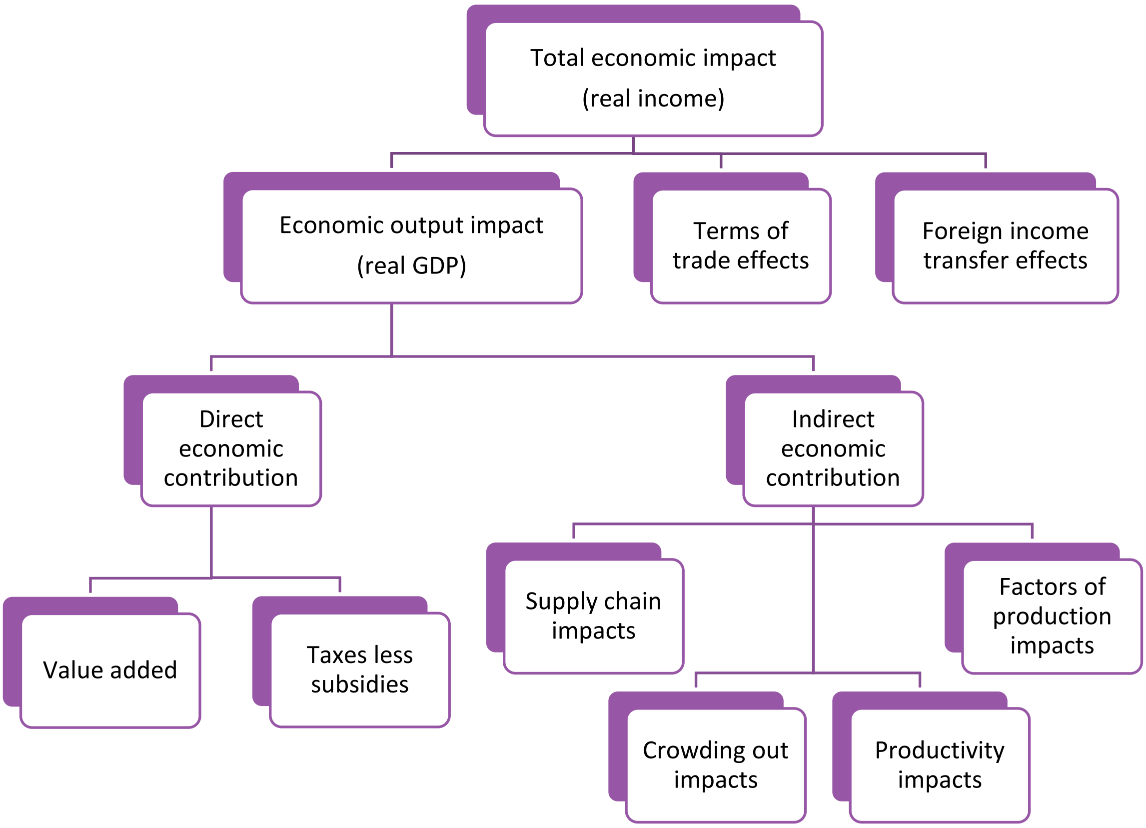
Fundamentally, although various aspects of a policy or project may be relevant to particular stakeholders—for example, the number of jobs created or the size of the investment expenditure—the key aggregate measure of the macroeconomic impact of a project or policy is the extent to which the total income of the economy has changed as a result of that policy or project. This is typically measured in terms of the change in real gross national disposable income (RGNDI), although real gross domestic product (GDP) and consumer surplus can also be important aggregate measures depending on the nature of the policy or project being analysed.

The main factors that need to be considered when analysing the macroeconomic impacts of a project or policy include:

— the direct and indirect contribution to the economy as a result of the activities associated with the project or policy
— any crowding out implications as resources are potentially diverted away from other productive activities to undertake the project or policy being analysed
— any productivity effects generated as a direct result of the policy or project activities – particularly any enduring productivity changes or productivity impacts on other activities not directly associated with the project or policy
— any changes to the factors of production in the economy
— any implications associated with changes in terms of trade or foreign income transfers
— the extent of any dynamic element to the size of any of the above effects (for example, associated with different phases of the project).

Figure 4.1 shows these components graphically. Some of these effects may be negligible while others may be significant. An understanding of the effects helps determine the most appropriate tool(s) for the analysis.

Figure 4.1 Estimating the macroeconomic impact of a project or policy



Note: In *Tasman Global*, the change in real income is equivalent to the change in equivalent variation – a standard economic measure of the change in consumer welfare resulting from exogenous shocks
Source: ACIL Allen

For many projects, static estimates of the direct economic contribution and of supply chain indirect economic contribution implications can be obtained using I-O multipliers. Estimating the size of other components using multiplier techniques is either not possible or very complex, as is estimating the economic impacts through time. In contrast, most CGE models can estimate all of the components shown in Figure 4.1 with dynamic CGE models able to estimate the impacts through time.

Given the substantial structural changes to the Australian economy associated with the energy transitions, CGE modelling has been chosen as the most appropriate tool to undertake the economic impacts assessment in this report.

4.1.2 The Tasman Global CGE model

Tasman Global is a large scale, dynamic CGE model of the world economy that has been developed in-house by ACIL Allen Consulting. Tasman Global is a powerful and effective tool for undertaking economic analysis at the regional, national and global levels.

CGE models mimic the workings of the economy through a system of interdependent behavioural and accounting equations which are linked to an I-O database. These models provide a representation of the whole economy, set in a national and international trading context. Starting with individual producers and consumers, the model builds up the economy through the demands and production from each individual actor in the face of interlinked markets. When an economic "shock" or disturbance is applied to a model, each of the markets adjusts according to a set of behavioural parameters which are underpinned by economic theory. The generalised nature of

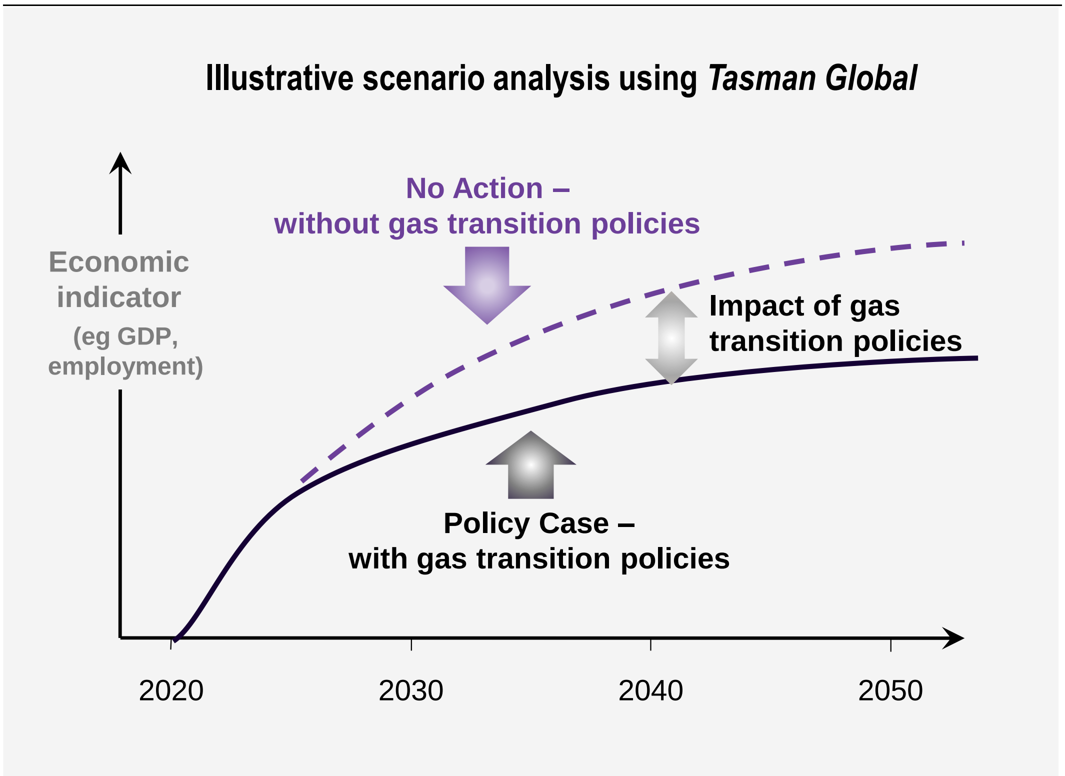
CGE models enable a much broader range of analysis to be undertaken (generally in a more robust manner) compared to I-O multiplier techniques.

A more detailed discussion of Tasman Global and its operation is provided in Appendix F.

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before a policy change and one following). A dynamic model such as Tasman Global is beneficial when analysing issues where both the timing of impacts and the adjustment path that economies follow are relevant in the analysis.

In applications of the Tasman Global model, a baseline simulation (in this exercise, the No Action scenario) provides a 'business-as-usual' scenario against which to compare the results of various simulations. The baseline provides projections of growth in the absence of the policies being considered. It therefore provides the base line projections of GDP, population, labour supply, industry output, and other relevant measures, and provides projections of endogenous variables such as productivity changes and consumer preferences. The policy scenarios assume all productivity improvements, tax rates and consumer preferences change as per the No Action scenario but also includes the proposed policies. The alternative scenarios result in different projections of the economy, and the net impacts of the policies can be calculated as the differences, for each relevant measure, between each policy case and the baseline (see Figure 4.2).

Figure 4.2 Illustrative scenario analysis using *Tasman Global*



Note: In practice, impacts could be negative, positive, neutral or a mixture
Source: ACIL Allen

4.2 Key assumptions

4.2.1 Constrained labour market

A key issue when estimating the impact of a project is determining how the labour market will clear.[19] As discussed in Section D.6, in the standard Tasman Global framework increases in the demand for labour in any state induced by the Project can be met by three mechanisms: increasing migration from the Rest of Australia; increasing participation rates and/or average hours worked; and by reducing the unemployment rate. In the standard model framework, the first two mechanisms are driven by changes in the real wages paid to workers in the local region while the third is a function of the additional labour demand relative to the baseline.

It should be noted that this analysis does not assume any change in net foreign migration as a result between the policy cases and the baseline.

4.3 Measures of macro-economic impacts

One of the most commonly quoted macroeconomic variables at a national level is real gross domestic product (GDP), which is a measure of the aggregate output generated by an economy over a given period of time (typically a year). GDP may be calculated in different ways:

— On the expenditure side by adding together total private and government consumption, investment and net trade.

— On the income side as the sum of returns to the primary factors of production (labour, capital and natural resources) employed in the national economy plus indirect tax revenue.

The regional level equivalent to GDP is gross regional product (GRP) – at the state or territory level it is called gross state product or gross territory product (GSP or GTP, respectively). To reduce the potential confusion with the various acronyms, the term **economic output** has been used in the discussion of the results presented in this chapter.

These measures of the real economic output of an economy should be distinguished from measures of the economy's real income, which provide a better indication of the economic welfare of the residents of a region. It is possible for real economic output to increase (that is, for GDP to rise) while at the same time real income (economic welfare) declines. In such circumstances, people and households would be worse off despite economic growth.

In *Tasman Global*, the relevant measure of real income at the national level is real gross national disposable income or RGNDI as reported by the Australian Bureau of Statistics.

As shown in Figure 4.1, the change in a region's real income as a result of a new project is the change in real economic output plus the change in net external income transfers plus the change in the region's terms of trade (which measure the change in the purchasing power of the region's exports relative to its imports).Changes in the terms of trade can have a substantial impact on residents' welfare independently of changes in real economic output.

In global CGE models such as *Tasman Global*, the change in real income is equivalent to the change in consumer welfare using the equivalent variation measure of welfare change resulting

[19] As with other CGE models, the standard assumption within *Tasman Global* is that all markets clear (i.e. demand equals supply) at the start and end of each time period, including the labour market. CGE models place explicit limits on the availability of factors and the nature of the constraints can greatly change the magnitude and nature of the results. In contrast, most other tools used to assess economic impacts, including I-O multiplier analysis, do not place constraints on the availability of factors. Consequently, these tools tend to overestimate the impacts of a project or policy.

from exogenous shocks. Hence, it is valid to say that the projected change in real income (from *Tasman Global*) is also the projected change in consumer welfare.

4.4 Economic modelling results

Undertaking a large scale transition of the Australian energy system will result in a range of macroeconomic impacts beyond those analysed in the cost benefit analysis. Some of these will be positive (such as energy efficiency improvements or reductions in gas purchases resulting in improving the competitiveness of Australian businesses or improving the cost of living for residents), while some will be negative (such as increased electricity purchases reducing the competitiveness of Australian businesses or increasing the cost of living for residents). Further, the relative local content of alternative investment or consumption options can also result in additional second or third round effects of the core drivers underlying each scenario. Indeed, in each scenario the complexities associated with the energy transition means that there are generally a wide range of competing positives and negatives for businesses and residents in any particular year meaning that it is difficult to disentangle individual impacts. In such circumstances, CGE models are generally the preferred tool for estimating the net macroeconomic impacts. This section presents the projected macroeconomic impacts using CGE modelling.

4.4.1 Real economic output and real income

As discussed in section 4.3, real economic output is the sum of value added by all producers in the relevant region/state, plus any product taxes (minus subsidies) not included in output. When calculated at a national level, this is referred to as gross domestic product (GDP), and as gross state product (GSP) at the state level.

In contrast, real income is a measure of the ability to purchase goods and services, adjusted for inflation, with the change in real income equal to:

— the change in real economic output (GDP/GSP)

— plus the change in net foreign income transfers

— plus the change in terms of trade.

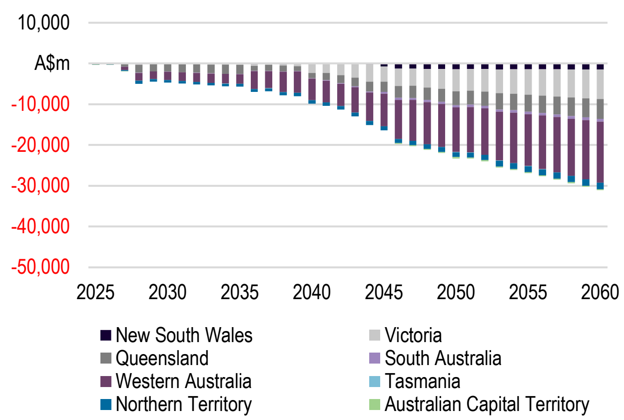
While the change in real economic output (GSP) is a useful indicator, real income provides a better measure of the welfare impact that changes in these aggregates have on people living in a region. A rise in real income indicates a rise in the capacity for current consumption, but also an increased ability to accumulate wealth in the form of financial and other assets.

Figure 4.3 shows the estimated annual change in real GSP for each state under each scenario, relative to the No Action scenario, while

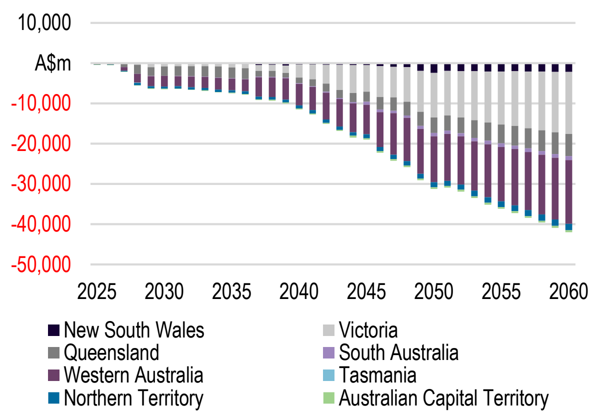
Table 4.1 presents the present value change over the period 2025 to 2060 inclusive. As we are comparing to a No Action scenario with no climate action, the changes in real economic output are generally negative.

Figure 4.3 Annual change in real economic output under each scenario relative to the No Action scenario ($m)

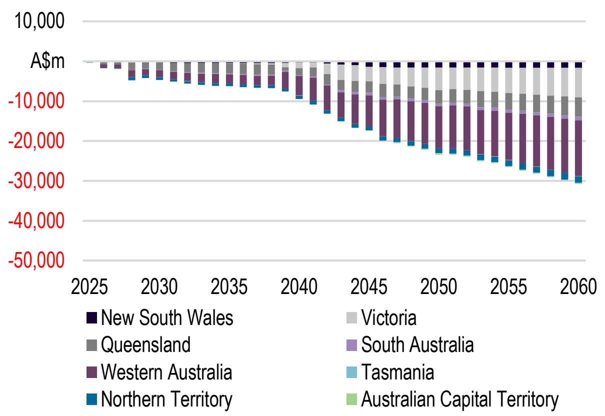
A. Theoretical Efficient Policy



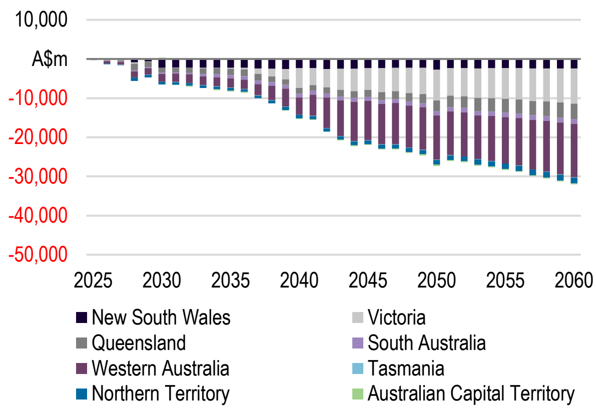
B. Electrify Everything Possible



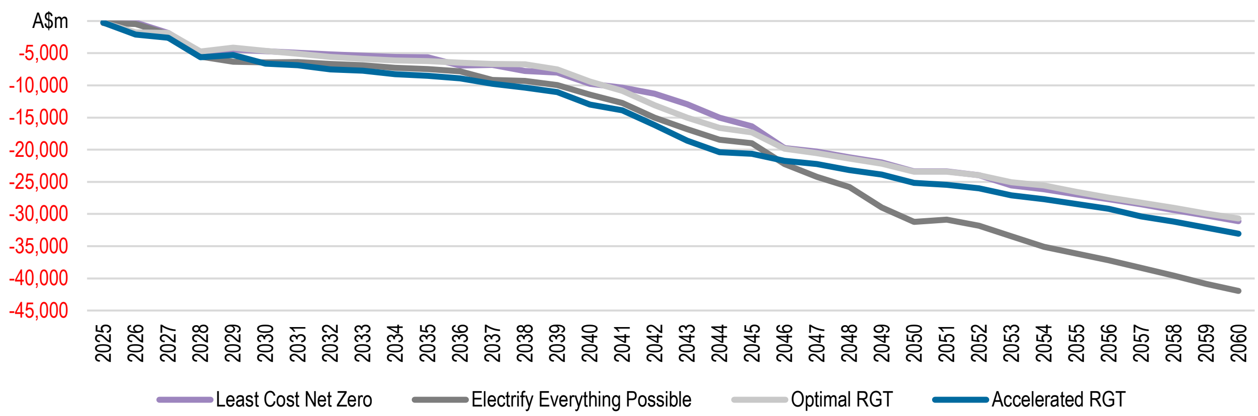
C. Optimal RGT



D. Accelerated RGT



E. Australia



Note: present value calculated using a 7% discount rate. Real economic output is commonly referred to as gross domestic product (GDP) at the national level, or gross state product (GSP) at the state level.

Source: ACIL Allen Tasman Global modelling

Table 4.1 Present value of change in real economic output by state under each scenario, relative to the No Action scenario

	Theoretical Efficient Policy	Electrify Everything Possible	Optimal RGT	Accelerated RGT
	$m	$m	$m	$m
New South Wales	-4,188	-6,243	-7,563	-20,449
Victoria	-20,140	-41,277	-18,961	-20,555
Queensland	-26,137	-30,070	-29,809	-27,352
South Australia	-2,023	-3,064	-3,633	-6,756
Western Australia	-58,550	-62,277	-53,998	-62,712
Tasmania	-176	-66	-157	-523
Northern Territory	-9,409	-8,842	-9,676	-9,537
Australian Capital Territory	-465	-2,634	-368	-2,155
Australia (GDP)	**-121,088**	**-154,473**	**-124,164**	**-150,039**
Change relative to Theoretical Efficient Policy	**0**	**-33,386**	**-3,077**	**-28,951**

Note: present value calculated using a 7% discount rate

Source: ACIL Allen Tasman Global modelling

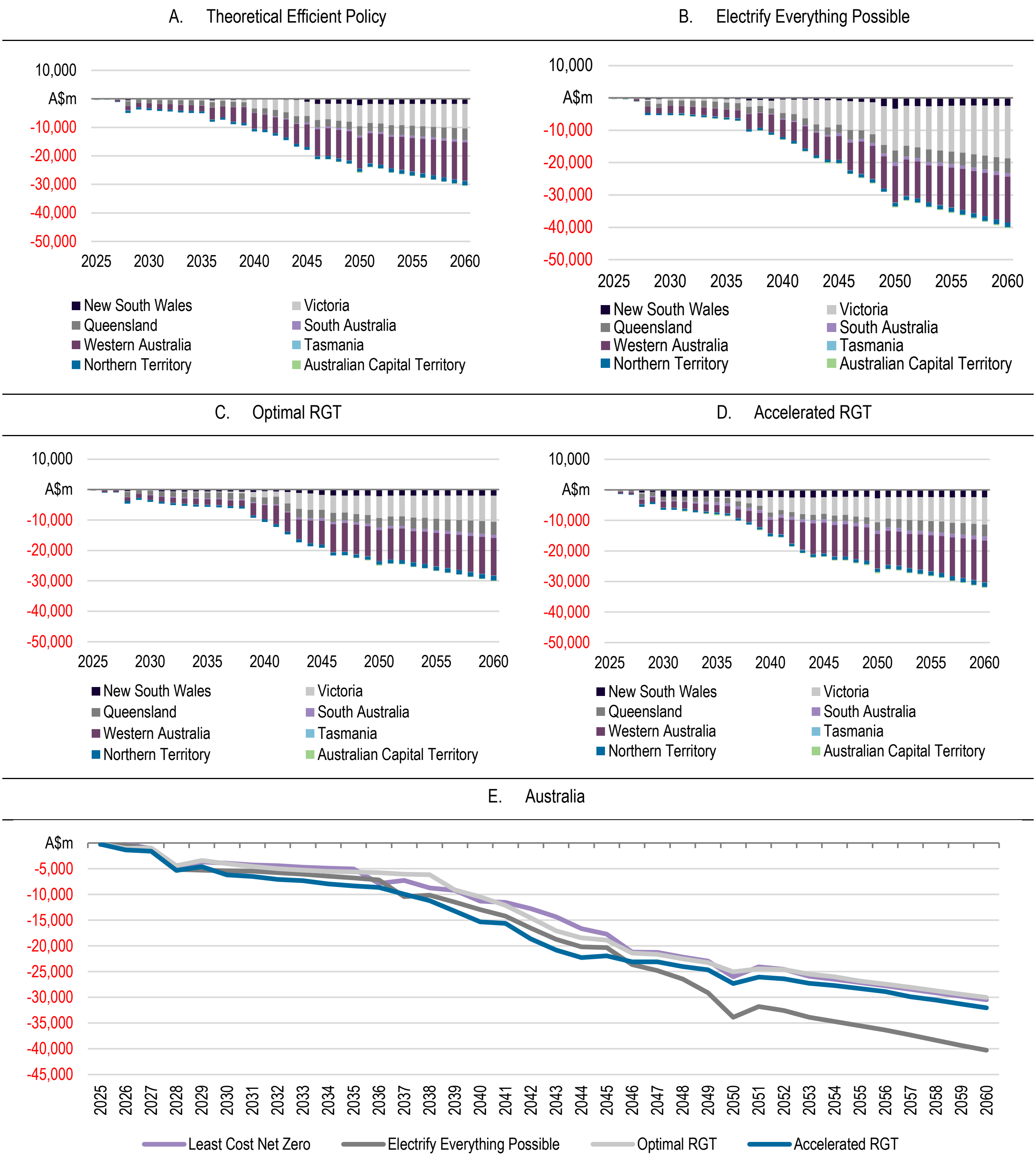
There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, energy prices and volumes, and efficiency changes. In total, over the period to 2060 the present value of the reduction in Australia's GDP relative to the No Action scenario (using a 7% discount rate) is:

— –$121.1 billion under the Theoretical Efficient Policy scenario
— –$154.5 billion under the Electrify Everything Possible Scenario
— –$124.1 billion under the Optimal RGT Scenario
— –$150.0 billion under the Accelerated RGT Scenario.

Each policy scenario reduces GDP relative to the No Action scenario because decarbonising the gas sector increases overall energy and appliance costs and reduces economic productivity. However, this views changes to Australia's gas sector in isolation from broader global efforts to reduce emissions, which will deliver economic benefits through reduced climate impacts on sectors such as agriculture, infrastructure and health. Further, the No Action scenario is inconsistent with national, state and territory government commitments to achieve net zero emissions by 2050, and therefore is not credible to assume that Australian governments will avoid transition costs in the gas sector at the expense of these overarching objectives – rather the objective of this modelling is primarily to identify the most efficient ways to achieve net zero. Therefore, these estimates of economic costs should be used to compare scenarios, rather than assess the overall costs and benefits of reducing emissions in Australia's gas sector as part of a wider global effort. Given this, the modelling demonstrates that policy options with lower direct gas sector costs such as the Theoretical Efficient Policy and Optimal RGT scenarios also translate to lower whole-of-economy costs. For example, adopting the Optimal RGT policy rather than an electrification-focused approach implied by the Electrify Everything Possible scenario would increase Australia's gross domestic product in the order of $30 billion (in present value terms) over the transition.

Figure 4.4 shows the estimated annual change in real income for each state under each scenario, relative to the No Action scenario, while Table 4.2 presents the present value of the total change over the period 2025 to 2060 inclusive.

Figure 4.4 Annual change in real economic income under each scenario relative to the No Action scenario ($m)



Note: present value calculated using a 7% discount rate

Source: ACIL Allen Tasman Global modelling

Table 4.2 Present value of change in real income under each scenario by state, relative to the No Action scenario

	Theoretical Efficient Policy	Electrify Everything Possible	Optimal RGT	Accelerated RGT
	$m	$m	$m	$m
New South Wales	-6,794	-9,013	-10,235	-24,198
Victoria	-26,575	-48,103	-25,274	-29,662
Queensland	-22,443	-25,290	-24,724	-20,716
South Australia	-2,592	-3,777	-4,549	-8,427
Western Australia	-55,090	-57,655	-49,644	-58,179
Tasmania	-321	-232	-290	-718
Northern Territory	-9,604	-8,904	-9,718	-9,457
Australian Capital Territory	555	-1,217	619	-1,043
Australia	**-122,863**	**-154,191**	**-123,816**	**-152,401**
Change relative to Theoretical Efficient Policy (Australia)	0	-31,328	-952	-29,537

Note: present value calculated using a 7% discount rate
Source: ACIL Allen Tasman Global modelling

In terms of the change in Australia’s real income, the cumulative difference relative to the No Action scenario is projected to be:

— –$122.9 billion under the Theoretical Efficient Policy scenario
— –$154.2 billion under the Electrify Everything Possible Scenario
— –$123.8 billion under the Optimal RGT Scenario
— –$152.4 billion under the Accelerated RGT Scenario.

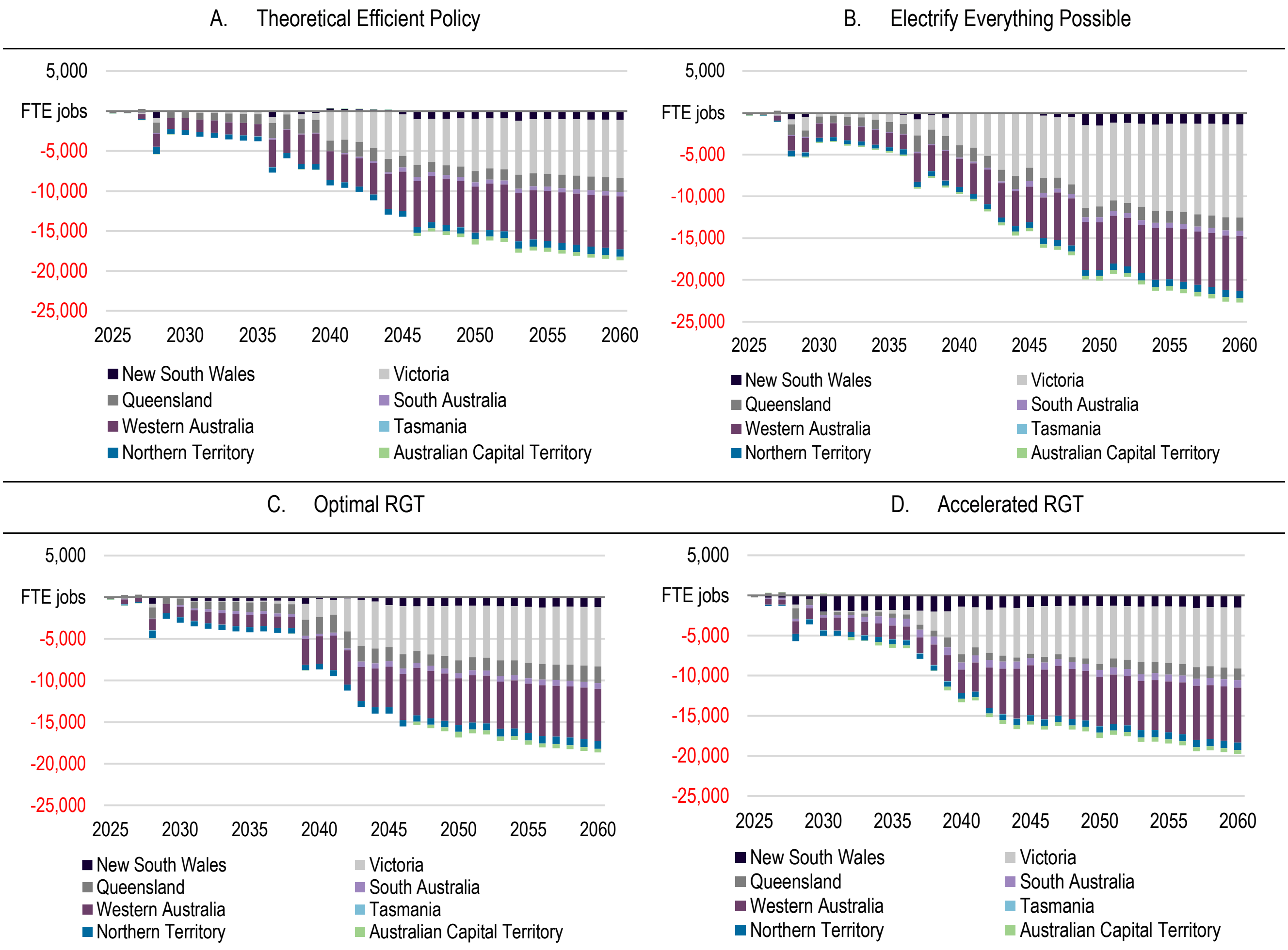
As for GDP, each policy scenario reduces real economic income relative to the No Action scenario because decarbonising the gas sector causes a negative shock to economic productivity. However, as the No Action scenario is inconsistent with national, state and territory government commitments to achieve net zero emissions by 2050, these estimates of changes to real economic income should be used to compare scenarios, rather than assess the overall costs and benefits of reducing emissions in Australia’s gas sector.

Policy options with lower direct gas sector costs such as the Theoretical Efficient Policy and Optimal RGT scenarios also translate to higher real economic income. For example, adopting the Optimal RGT policy rather than an electrification-focused approach implied by the Electrify Everything Possible scenario would increase Australia’s real income in the order of $30 billion (in present value terms) over the transition.

4.4.2 Employment

Figure 4.5 presents the annual change in employment under each scenario relative to the No Action scenario.

Figure 4.5 Annual change real employment under each scenario relative to the No Action scenario



Source: ACIL Allen Tasman Global modelling

Table 4.3 Cumulative and annual average change in employment under each scenario by state, relative to the No Action scenario

	Theoretical Efficient Policy	Electrify Everything Possible	Optimal RGT	Accelerated RGT
Cumulative (2025-2060)	Employee years	Employee years	Employee years	Employee years
New South Wales	-17,001	-21,434	-24,485	-51,307
Victoria	-129,622	-192,983	-124,798	-147,565
Queensland	-48,298	-45,052	-50,221	-29,349
South Australia	-9,703	-11,468	-15,745	-26,800
Western Australia	-141,707	-139,624	-131,904	-148,820
Tasmania	-324	288	-53	-806
Northern Territory	-24,705	-22,145	-25,204	-24,890
Australian Capital Territory	-7,106	-11,381	-6,587	-12,761
Australia	**-378,465**	**-443,799**	**-378,997**	**-442,299**
Change relative to Theoretical Efficient Policy (Australia)	**0**	**-65,333**	**-531**	**-65,553**
Annual average	FTE jobs	FTE jobs	FTE jobs	FTE jobs
New South Wales	-472	-595	-680	-1,425
Victoria	-3,601	-5,361	-3,467	-4,099
Queensland	-1,342	-1,251	-1,395	-815
South Australia	-270	-319	-437	-744
Western Australia	-3,936	-3,878	-3,664	-4,134
Tasmania	-9	8	-1	-22
Northern Territory	-686	-615	-700	-691
Australian Capital Territory	-197	-316	-183	-354
Australia	**-10,513**	**-12,328**	**-10,528**	**-12,286**
Change relative to Theoretical Efficient Policy (Australia)	**0**	**-1,815**	**-15**	**-1,773**

Source: ACIL Allen Tasman Global modelling

As for GDP and real economic income, decarbonising the gas sector causes a negative shock to economic productivity and so reduces employment relative to the No Action scenario. However, as the No Action scenario is inconsistent with national, state and territory government commitments to achieve net zero emissions by 2050, these estimates of changes to employment should be used to compare scenarios, rather than assess the overall costs and benefits of reducing emissions in Australia's gas sector. Policy options with lower direct gas sector costs such as the Theoretical Efficient Policy and Optimal RGT scenarios have smaller effects on employment, that is, higher employment than under the Electrify Everything Possible and Accelerated RGT scenarios.

Appendices

Wholesale gas market modelling A

This appendix outlines the key gas market assumptions, modelling methodology, and results that were used to inform the transition model.

A.1 Market assumptions

A.1.1 East Coast Gas Market

ACIL Allen was recently engaged by AEMO to undertake price projections to inform the Annual Inputs and Assumptions Report (IASR) and Gas Statement of Opportunity for 2024 within the East Coast Gas Market (ECGM) and Northern Territory. As a part of this work ACIL Allen aligned key gas market assumptions within our proprietary modelling software GasMark with AEMO's assumptions. As such our standard models which form the starting point for our modelling work, are well aligned with AEMO.

To define the resource cost for the ECGM ACIL Allen built on the assumptions used by AEMO to clearly define 2 scenarios that represent a Low and a High scenario for gas consumption. The key aspects of these scenarios are contained in Table A.1.

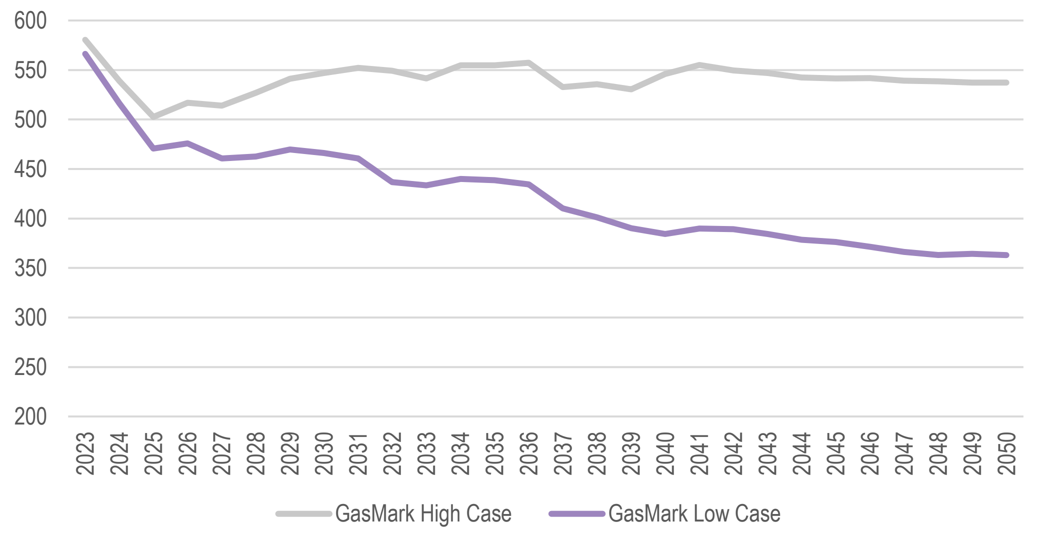
Table A.1 ECGM Model Assumptions

Assumption	Low Case	High Case
Demand	Orchestrated Scenario Demand from 2023 GSOO	Demand without impact of electrification of gas load
Reserves and Resources	2P reserves + 2C resources Broadly Aligned with 2023 GSOO and Industry	2P reserves + 2C resources Broadly Aligned with 2023 GSOO and Industry
Production Costs	Aligned with 2023 GSOO and industry	Aligned with 2023 GSOO and industry
New Gas Supply NSW	Narrabri proceeds from 2026	Narrabri proceeds from 2026
New Gas Supply VIC	**Gippsland** – GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** – Enterprise in 2024 and Thylacine from 2023 **Bass** – Trefoil is developed	**Gippsland** – GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** – Enterprise in 2024 and Thylacine from 2023 **Bass** – Trefoil is developed
New Gas Supply QLD	Bowen Basin – Mahalo project (Santos)	Bowen Basin – Mahalo project (Santos)
New Gas Supply SA	No New Projects	No New Projects
New Gas Supply NT	Beetaloo – long term supply capacity of 50PJ available for ECGM	Beetaloo – long term supply capacity of 100PJ available for ECGM

Assumption	Low Case	High Case
Pipeline Developments	According to 2023 GSOO	According to 2023 GSOO Plus significant additional expansions to SWQP, MSP, and EGP to transport northern supply south to meet demand.
Pipeline Expansion Costs	N/A	$60,000/inch km at 8%/annum for 40yrs
Pipeline Tariffs	According to 2023 GSOO	According to 2023 GSOO
Global Long Term Oil Price	Long term US$65 per barrel	Long term US$65 per barrel
QLD LNG Exports	ACIL Allen Reference Case Assumptions	ACIL Allen Reference Case Assumptions

Figure A.1 displays the demand assumptions for the two scenarios. The Low case (AEMO's Orchestrated Scenario) assumes a considerable reduction in gas consumption over the projection period. This is primarily due to electrification driven demand destruction, and fuel switching as part of the push for net zero by 2050 and other interim climate objectives. The high case presents an alternate view where business as usual prevails and gas usage does not decrease over time. As discussed further in the results section, the sustained high consumption levels in the high case have implications with respect to resource costs when field depletion and supply dynamics to meet the demand are considered. These factors are what is important when comparing the cost of sustaining the gas industry at such a level, and form part of the resource cost formula.

Figure A.1 ECGM gas demand, by case (PJ)



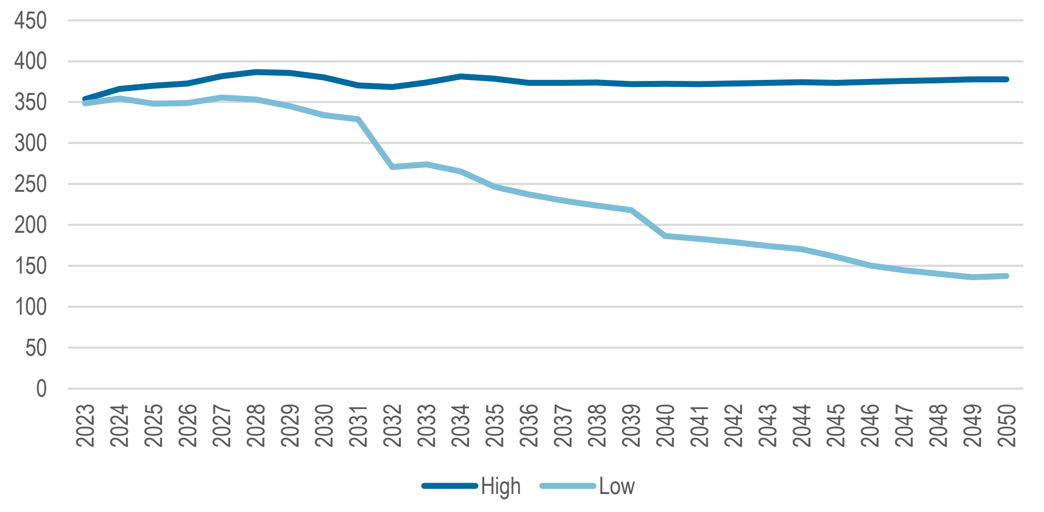
A.1.2 West Coast Gas Market

The West Coast Gas Market (WCGM) is at a similar but less extreme tipping point to the ECGM with comparable pressure to electrify and decarbonise, however these forces are muted by the gas reservation policy which has to date ensured price and supply security. The continuation of this supply/demand balance is contingent on the timeline of key Greenfield LNG fields and onshore domestic gas development. As in the ECGM, ACIL Allen has defined a high and low scenario for the WCGM. The low case in this instance follows ACIL Allen's view of a 'most likely' demand scenario given electrification of industry groups within the Western Australian market. The High case again represents a situation where business as usual gas consumption prevails and extends throughout the projection period, allowing the cost of retaining gas to be properly examined. The key aspects of these scenarios are contained in Table A.2, and Figure A.2 displays the demand assumptions for the two scenarios.

Table A.2 WCGM Model Assumptions

Assumption	Low Case	High Case
Demand	ACIL Allen Reference Case	Demand without impact of electrification of gas load
Reserves and Resources	2P reserves + 2C resources Broadly Aligned with 2022 GSOO WA and Industry	2P reserves + 2C resources Broadly Aligned with 2022 GSOO WA and Industry
Production Costs	Broadly Aligned with industry	Broadly Aligned with industry
New Gas Supply Onshore	West Erregulla from 2025, Lockyer Deep from 2026	As in low case
New Gas Supply Offshore Domestic	Corvus by 2028	Corvus by 2028
New Gas Supply Offshore Domestic Gas Obligation	Scarborough by 2027	Scarborough by 2027, Browse by 2032
Pipeline Developments	Not required	Not required
Pipeline Expansion Costs	N/A	N/A
Pipeline Tariffs	Broadly Aligned with industry	Broadly Aligned with industry
Global Long Term Oil Price	Long term US$65 per barrel	Long term US$65 per barrel
LNG Exports	ACIL Allen Reference Case Assumptions	ACIL Allen Reference Case Assumptions

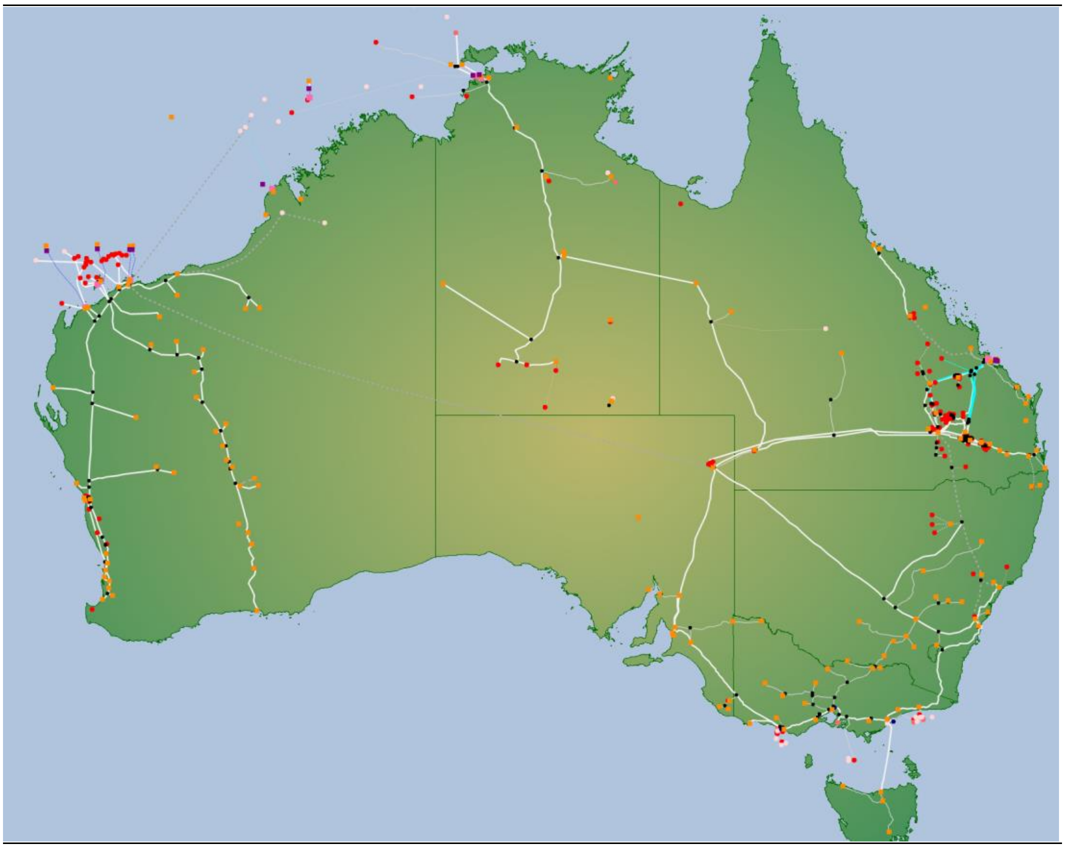
Figure A.2 WCGM demand, by case (PJ)



A.2 GasMark modelling

ACIL Allen uses our in-house market modelling software 'GasMark Global' to generate projections of future supply demand balance and estimate wholesale gas prices. GasMark operates as a partial spatial equilibrium model, representing the market as a set of consuming or producing nodes connected via a network of pipelines or LNG shipping elements. The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. GasMark contains a detailed representation of the of the entire Australian gas market topology as shown in Figure A.3 below.

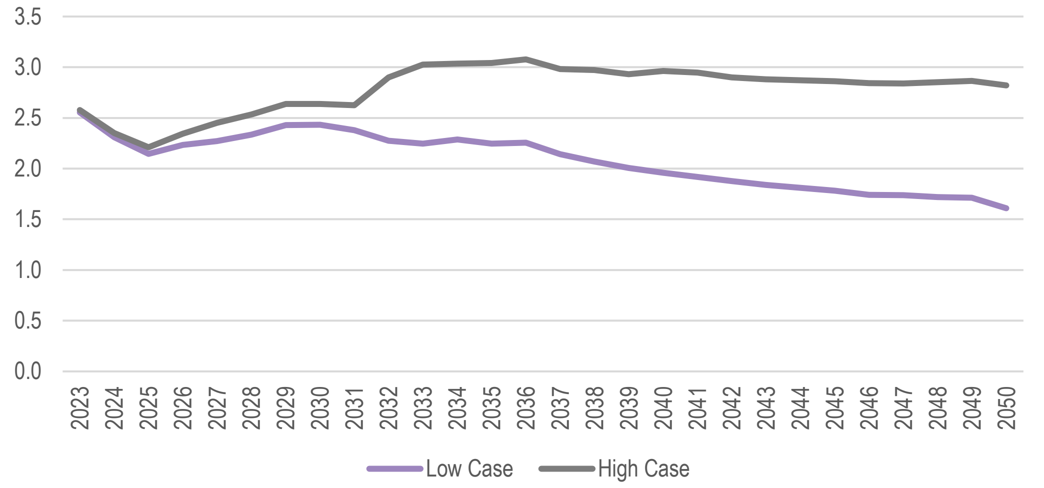
Figure A.3 GasMark network topology for the Australian gas market



A.3 Results

Supply dynamics within the east coast gas market are in the midst of a fundamental shift. Southern production is declining and incrementally being replaced by gas sourced from Queensland's LNG-dominated coal seam gas fields. This trend is set to continue over the projection period, and when paired with AEMO's electrification assumptions, the system manages to tightly avoid short falls and price escalation. This is the story in the Low case. The high case however sees a more rapid depletion of southern supply and thus a much heavier reliance on northern gas production, necessitating major pipeline expansion to avoid shortfalls. Under the high case, as mature and prospective fields are depleted, the cost of production slowly escalates as the cheaper reserves are depleted first. These dynamics when combined define the resource cost for each scenario.

Figure A.4 ECGM annual resource cost, by case (real 2023 $billion)



The resource cost as presented here is the sum of the levelized production cost at the current production tranche per field by production volume per field, plus 10% of pipeline tariff revenue[20] plus annuity payments to support pipeline expansions as required.

Expressed as an equation as follows.

$$\begin{aligned} ResourceCost = {} & \sum(LevelizedProductionCost \times \text{ProductionVolume}) \\ & + (0.1 \times \sum\text{PipelineTariff revenue}) + \text{PipelineExpansionAnnuity} \end{aligned}$$

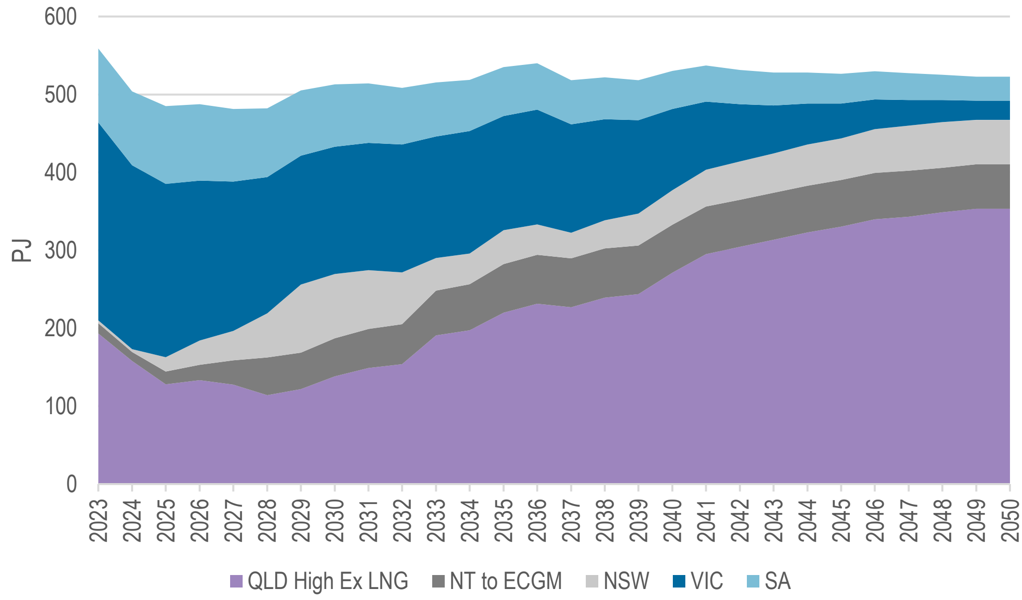
GasMark contains the cost of production expressed in terms of the levelized production cost of the current tranche of development per field; thus, distilling all associated production capital and operational investments/costs into a $/GJ figure per field tranche.

The High and Low cases consistently exhibit a significant separation in resource cost from early in the projection period. This separation widens significantly during the early 2030s due to the necessary expansion of key pipeline infrastructure to facilitate higher capacity delivery of northern gas to southern markets. Modelling projects it is necessary to build out an additional 400 TJ/day capacity at the SWQP and MSP pipeline systems, as well as an additional 140 TJ/day along the EGP.

Figure A.5 shows how the share of production by state jurisdiction evolves over time within the high case. This figure clearly illustrates the challenge that supplying a high gas consumption scenario and the justification for pipeline expansion projects under this scenario.

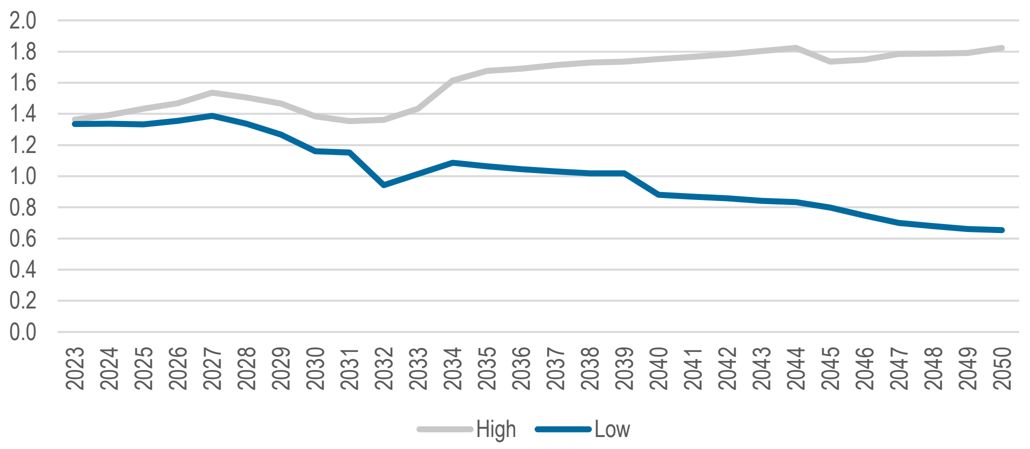
[20] Reflecting a high-level assessment of variable and operating costs for transmission pipelines as a proportion of the headline tariffs.

Figure A.5 ECGM gas production, by state



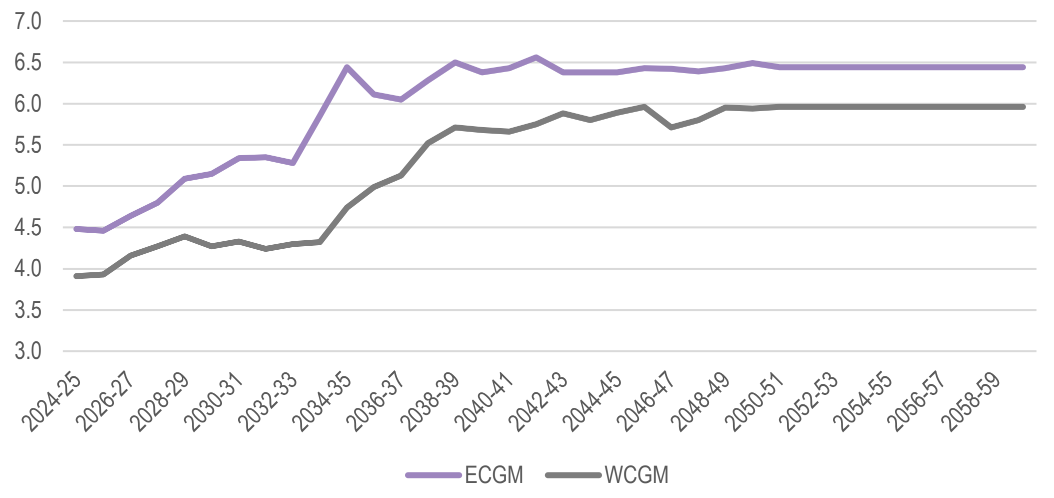
Resource costs in the WCGM diverge significantly between the high and low cases (Figure A.6), which is similar to the high-level result for the ECGM. However, this divergence occurs for different reasons in the two markets. Since pipelines are not constrained in WA, and there is no expected change to the geographic supply origin of gas as in the ECGM, there is not expected to be any additional pipeline capital cost to retaining gas consumption at current levels over the projection period. In the case of the WCGM, the driving factor in escalating the total resource cost for the high case is the underlying changes in cost of production as low-cost fields are depleted and new higher cost fields are added.

Figure A.6 WCGM resource cost, by case ($billion)



For use in the transition model, the total resource cost was converted back into a homogenised fuel cost. For the high cases of the ECGM and WCGM respectively the yearly fuel prices (contained in the figure below) formed the inputs for the transition model.

Figure A.7 Resource cost per unit of gas production, by market ($/GJ)



Wholesale electricity market modelling B

This appendix outlines the key electricity market assumptions, modelling methodology, and results that were used to inform the transition model.

B.1 Market assumptions

B.1.1 National Electricity Market

Cost inputs for the NEM have utilised AEMO's Plexos modelling as part of the 2022 ISP Step Change scenario. Load-weighted prices from the LT planning model were extracted and these used as variable fuel resource costs for gas-based appliances.

As the Step Change scenario operates under a fixed emissions budget, any incremental demand has zero net emissions and the prices utilised reflect the need for firmed zero emission generation to meet incremental demand stemming from electrification.

B.1.2 Western Australian Wholesale Electricity Market

ACIL Allen has developed an updated market outlook of the WEM – the Reference case projection. The Reference case incorporates the best information available to ACIL Allen at the time that the case is developed and reflects current market conditions including any recent changes such as (but not limited to):

— new supply and retirements
— fuel costs
— demand
— generator investment costs
— government policy.

Assumptions utilised in the Reference case generally reflect a mid-case view. For example, we adopt forecast P50 peak demand and energy under the 2023 ESOO Central scenario, projected mid-case gas prices from our in-house gas market model (*GasMark*), and generator investment costs under the 2023 IASR assumptions Global NZE by 2050 scenario.

All assumptions used in the modelling are taken from publicly available or in-house information and databases maintained by ACIL Allen. The Reference case is intended to reflect a median or 50th percentile view and was current as at October 2023.

Table 1.4 Overview of WEM Reference case assumptions

Assumption	Details			
Macro-economic variables	Exchange rate of AUD to USD converging to 0.75 AUD/USD. Inflation of 2.5 per cent per annum. The brent crude oil price is assumed to converge from current levels to USD65/barrel by the mid-2020s and remain at this level in the long-term.			
Electricity demand	**Underlying demand** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario (energy and POE50 peak demand).	**Rooftop PV** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario, which extends to 2032 and ACIL Allen extrapolates this though to 2050.	**Behind-the-meter BESS** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario, which extends to 2032 and ACIL Allen extrapolates this through to 2050.	**Electric vehicles** AEMO 2023 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario, which extends to 2032 and ACIL Allen extrapolates this through to 2050. Assumed charging profiles are a blend of three charging behaviours that changes over time as charging infrastructure is developed. Profiles include an overnight charging profile, a daytime charging profile and a late evening/convenience charging profile.
State-based policies	In June 2022, the WA Government announced the accelerated closure of the Synergy coal fleet in response to the challenge from incorporating rooftop solar PV and the desire to decarbonise the electricity grid at a faster rate. The revised closure schedule is: Muja C Unit 5 late 2022 (no change); Muja C Unit 6 in 2024 (no change); Collie in late 2027; Muja D in late 2029. As part of these changes, the State Government has also committed to not commission any new natural gas-fired power stations on the SWIS after 2030. This closure schedule has been incorporated into the Reference case however the modelling still allows for the entry of gas-fired generation post 2030. Bluewaters is assumed to close by 2029-30, on the assumption that the Griffin coal mine, which supplies coal to Bluewaters, ceases operations.			
Federal greenhouse gas emission policies	Economy-wide 43 per cent reduction in GHG emissions below 2005 levels by 2030 and a net zero emissions target by 2050. Retention of the LRET in its current form to 2030 is assumed, with no extension beyond 2030.			
Electricity supply (beyond new supply driven by state based schemes)	**Assumed new entry and closures** Committed or likely committed generator closures included where the closure has been announced by the participant, including: Muja C unit 6 in late 2024	**Assumed new entry and closures** Named new entrant projects are included in the modelling where there is a high degree of certainty that these will go ahead (i.e., project has reached financial close) including: Flat Rocks wind farm stage 1 (76 MW) for capacity year 2024-25		**Projected new entry and closures** Beyond committed and assumed projects, only commercial generic new entrants are introduced within the modelling. Closure of existing generators where the generator is projected to be unprofitable over

Assumption	Details			
	Collie in late 2027 Muja D in late 2029, Tiwest cogen in 2028 Pinjar in 2031-32 Pinjarra cogen in 2035-36 Cockburn in 2039	Cunderdin Solar farm (100 MW) and battery (55 MW/ 220 MWh) for capacity year 2024-25 Synergy's Kwinana 2 battery (200 MW/ 800 MWh) for capacity year 2024-25 Neoen's Collie battery (200 MW/ 800 MWh) for capacity year 2024-25 Alinta's Wagerup battery (100MW/ 200 MWh) for capacity year 2025-26 Several wind, solar and battery storage projects that are considered probable or close to committed including: Synergy's Collie battery (500 MW/ 2,000 MWh) for capacity year 2025-26 Neoen's Muchea battery (500 MW/ 2,000 MWh) for capacity year 2025-26 Bristol Springs solar farm stage 1 (114 MW) for capacity year 2025-26 King Rocks wind farm (150 MW) for capacity year 2025-26 ocks wind farm stage 2 (100 MW) for capacity year 2026-27		an extended period of time or the generator's expected closure year as indicated by AEMO, whichever is earliest.
New entrant capital costs (renewables and storage)[a]	**Wind** $2,825/kW in 2023 $2,115/kW in 2030 $1,851/kW in 2040 $1,762/kW in 2050	**Solar (single axis tracking)** $1,681kW in 2023 $1,191/kW in 2030 $738/kW in 2040 $551/kW in 2050	**Battery storage (four hours)** $2,335/kW in 2023 $1,116/kW in 2030 $774/kW in 2040 $697/kW in 2050	**CCGT – H2 ready** $1,888/kW in 2023 $1,810/kW in 2030 $1,724/kW in 2040 $1,677/kW in 2050
Gas prices into gas-fired power stations	The WEM modelling assumes consistent gas price commodity assumptions for all gas-fired generation. Only variable charges on the Dampier to Bunbury pipeline are included in generators SRMC. Some variations around this generic gas price series are applied to generator which operate based on legacy contracts such as NewGen which is assumed to operate on its existing gas contract until expiry. In real 2023 terms, assumed gas prices rise from $7/GJ in 2023 to $10/GJ by 2050.			
Coal prices into coal-fired power stations	Coal prices are assumed to rise by around $1.50/GJ (~$30/tonne) in 2023 owing to the supply issues at Premier and Griffin mines, supplemented with imported thermal coal from NSW where required. In real 2023 terms, assumed coal prices into power stations are $4.75/GJ.			

[a] ACIL Allen's modelling considers battery storage technologies of varying duration – the four-hour batteries are the most prevalent duration option in our modelling results.
Note: Unless stated otherwise, all dollar values in this table are presented in real 2023 AUD.
Source: ACIL Allen

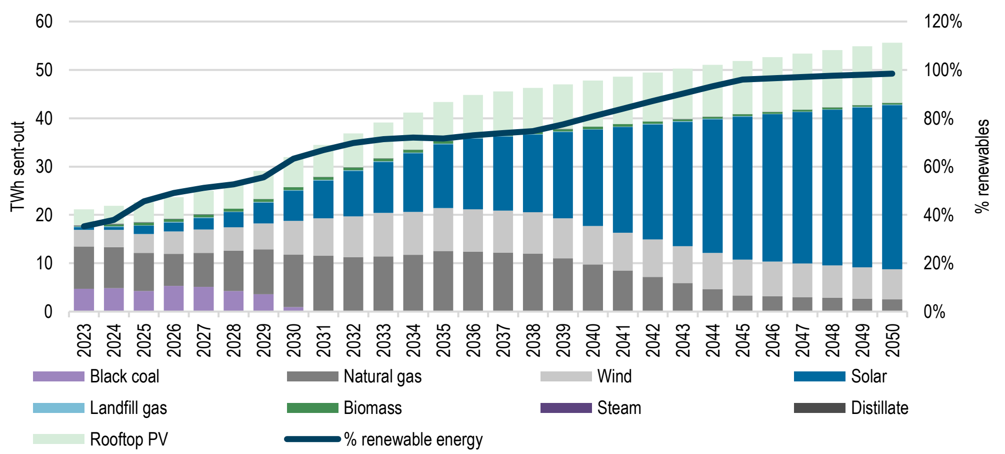
The figure below shows the projected WEM dispatch summarised by fuel type over the period to 2050. Overall consumption volumes grow over time with electrification of industrial processes (primarily alumina), a growing charging load from the uptake of electric vehicles, and some growth in residential and other industrial sectors, which is partially offset by growth in rooftop PV generation.

Coal volumes are projected to remain at historically low levels (less than 5.5 TWh) with supply constraints and higher input prices. Coal generation volumes decline significantly by 2030, with the retirement of the second unit at Muja C in 2024, Collie from 2027-28, Muja D from 2029-30, and Bluewaters from 2030-31, with high efficiency gas-fired generation, battery developments, wind, and solar generation to replace lost capacity and generation volumes.

Renewable penetration is projected to increase from 35% in 2023 to 60% in 2030 and to 99% in 2050.

Natural gas generation volumes (including renewable gas generation after 2040) are projected to increase between 2026 and 2035 as coal closures occur, and then decline over time as older gas-fired generators are retired.

Figure B.1 Projected WEM dispatch: October 2023 Reference case



Source: ACIL Allen PowerMark modelling

Wholesale hydrogen cost modelling C

This appendix outlines the key assumptions we used to model wholesale renewable ('green') hydrogen costs for the Gas Transition Model. We modelled these costs based on two production approaches:

— Firmed production on a 'standalone' basis (that is, using dedicated solar and wind generation that does not interact with the wider electricity grid, as well as dedicated electrolysers, hydrogen storage and pipelines) that delivers a constant 'firmed' flow of hydrogen to a notional user. These costs are likely to be reflective of large-scale hydrogen production such as for major industrial facilities or export-oriented industry. We have modelled these costs based on solar and wind resources available in relatively geographically unconstrained Renewable Energy Zones (REZs), and so we have assumed that the available volume of hydrogen at our modelled price is essentially unlimited.

— An unfirmed series where the flow of hydrogen can vary, reflecting a situation where it is being blended into a larger natural gas supply stream and so can vary in line with the availability of solar and wind. This series was calculated based on the ability of grid-connected electrolysers to flexibly operate at times of low wholesale electricity prices, and this flexibility, combined with the lack of storage costs, means that this series is lower cost than the firmed series. However, we have limited the volume of this unfirmed hydrogen that can be used in the transition model to 3% of overall gaseous fuel demand to reflect technical limits on blending hydrogen into the general natural gas supply.

C.1 Firmed hydrogen modelling methodology

ACIL Allen's approach to modelling standalone firmed hydrogen production costs is to find the optimal mix of solar, wind, and electrolyser capacity to minimise the cost of hydrogen supply. This optimal mix will vary from REZ to REZ, and from year to year, reflecting differences in:

— solar and wind capacity factors, which vary by REZ reflecting the quality of renewable resources specific to that location

— solar and wind generation patterns (captured in AEMO's detailed half-hourly 'traces' for each resource and each REZ, modelled across 29 notional model years that reflect a mix of historically observed weather patterns in that REZ)

— equipment capital costs, with solar and electrolyser costs in particular assumed to decline over time (wind also declines, but not as fast, while we have assumed that large-scale hydrogen storage costs do not decline at all over time)

— storage and firming costs, which generally involves some over-sizing of solar, wind and electrolysers to economise on storage costs

— pipeline costs reflecting the distance of specific REZs from major demand centres.

We modelled both the most challenging year for each REZ (estimated as the model year with the lowest combined solar and wind capacity factor for that REZ) and a typical year for each REZ (estimated as the model year with the median combined solar and wind capacity factor for that REZ). The costs between these two approaches was small – typically $1 to $3 per gigajoule – and so we have adopted results based on a typical weather year.[21] We have calculated the C-2evelized lifecycle cost of projects using an assumed weighted average cost of capital of 7% real).

Some elements of the cost-modelling – for example, pipeline costs – are sensitive to scale. We have assumed a standard project size of 25 petajoules per year for large-scale firmed supply, which would be reflective of a very large industrial user or cluster of medium-to-large-sized users.

As noted above, we have modelled relatively geographically unconstrainted REZs to reflect our assumption that supply volumes are essentially unlimited in the model. Table C.1 summarises the REZs and demand locations modelled, which consists of particularly 'scalable' REZs, with very large land areas available and that are further from existing NEM transmission, where building the solar and wind capacity required for large-scale hydrogen production would be less likely to conflict with spatial and social licence constraints arising from the need to also build solar and wind generation to supply general NEM demand.

Table C.1 Modelled REZs

State	Firmed REZs
Queensland	Q2: North Queensland Clean Energy Hub, piped to Gladstone Q8: Darling Downs, piped to Brisbane
New South Wales	Q2, piped to Newcastle Q8, piped to Newcastle N1: North-west NSW, piped to Newcastle N3: Central-west Orana, piped to Newcastle
Victoria	V2/V3: Murray River (solar) and Western Victoria (wind), piped to Geelong
South Australia	S6: Leigh Creek, piped to Adelaide

Due to a lack of physical space and competition with NEM-connected resources, we have not modelled a Tasmanian REZ. Western Australia and the Northern Territory are not included in the ISP and so AEMO does not publish equivalent solar and wind trace data for WA, and so it has not been possible for us to model Western Australian REZs. For the purpose of modelling, we have assumed that Tasmanian hydrogen prices are the same as Victorian prices, and Western Australian and Northern Territory prices are the same as Queensland prices.

C.1.1 Key assumptions

Solar, wind and electrolyser assumptions

Solar, wind and electrolyser capital costs are the largest cost components of standalone green hydrogen production. For consistency with the electricity sector modelling used in this analysis, we have adopted AEMO's 2022 ISP assumptions for solar and wind and adjusted for inflation to convert them to present day (2023) dollars.

For electrolyser costs, AEMO's published ISP assumptions focus on proton exchange membrane (PEM) electrolysers rather than alkaline electrolysers, despite the latter's lower capital cost. We have used CSIRO's GenCost study (which is itself an input to the ISP) to derive a comparable

[21] Hydrogen consumers may agree to flexible contract terms (e.g. temporary consumption reductions) to avoid the cost of paying for infrastructure to supply hydrogen across all possible weather conditions. Accordingly, we consider the 'typical year' cost to be a fair reflection of likely long-term hydrogen contract prices, though weather and general commercial risk may result in a small premia over these prices.

alkaline electrolyser cost, as the lower capital cost of these electrolysers supports more cost-competitive hydrogen production.

Solar and wind costs are the largest cost component in hydrogen production. They comprise about 60% of firmed hydrogen supply cost in our modelling on average, and about 67% of the cost of unfirmed supply. Electrolysers are the second largest cost component, comprising 20% of firmed supply cost and 26% of unfirmed supply.

Another important assumption is electrolyser efficiency, as this determines the volume of solar and wind generation that must be built to deliver a given volume of hydrogen. AEMO does not publish an alkaline electrolyser efficiency series, but following the IEA,[22] we have assumed that alkaline electrolysers have the same efficiency as AEMO's published PEM efficiency series.

Hydrogen storage costs

Hydrogen storage is important to firm hydrogen supply, and the cost of various forms of hydrogen storage are relatively uncertain. We have followed a US study by researchers from the Argonne National Laboratory to assume standardised per unit costs for three forms of storage:

— salt caverns
— lined rock caverns
— dedicated pipeline storage.

Table C.2 summarises the key assumptions drawn from this study.

Table C.2 Hydrogen storage assumptions

Storage type	Capital cost	Cushion gas requirement
	2021 USD/kg	% of installed capacity
Salt caverns	36.8	31%
Lined rock caverns	59	17%
Dedicated pipeline storage	516	9%

Source: Papadias D and Ahluwalia R, Bulk storage of hydrogen, International Journal of Hydrogen Energy, https://doi.org/10.1016/j.ijhydene.2021.08.028

As salt caverns can only be created in suitable salt deposits, they are limited to certain locations with suitable geology. Within the scope of this modelling, we allow hydrogen producers to access salt cavern storage in either the Adavale basin in south-western Queensland or the Amadeus Basin in southern Northern Territory, but this choice also incurs an additional cost of pipeline transport to the salt cavern location.

On the assumptions used in this work, we find that the more locationally flexible lined rock caverns are generally more economical, as they avoid the need for long dedicated pipelines and also have lower cushion gas requirements. Salt cavern is only selected for one supply option: when supply from the North Queensland Clean Energy Hub (Q2) is delivered to New South Wales, the pipeline corridor passes close by the Adavale Basin and so the incremental pipeline distance required is small. In 2029-30 when the storage requirement is relatively large, the saving from using salt cavern storage instead of lined rock cavern storage is enough to overcome the additional pipeline cost, but this is not the case in later years when cheaper renewable generation and electrolysers reduces the need for storage. On the assumptions sourced above dedicated pipeline storage is more expensive than underground storage and so is not selected in our modelling.

Hydrogen storage comprises about 10% of the cost of firmed hydrogen production in our modelling.

[22] IEA 2023 Electrolysers, https://www.iea.org/energy-system/low-emission-fuels/electrolysers.

Pipeline transport costs

Pipeline transport costs, including the option of 4, 12, or 24 hours of linepack storage, are derived from a recent study undertaken on behalf of APGA.[23] Pipeline costs are incurred to transport hydrogen from the production REZ to the nearest major load centre or pipeline connection point (and to dedicated salt cavern storage locations when that storage option is selected). The spatial assumptions for this modelling are summarised in Table C.3. Pipeline transport comprises about 9% of the cost of firmed hydrogen production in our modelling.

Table C.3 Spatial assumptions for pipeline transport costs

REZ	Assumed production centre	Assumed load centre or connection point	Distance from production to load centres (km)
North Queensland Clean Energy Hub	Hughenden	Gladstone	1100
North Queensland Clean Energy Hub	Hughenden	Newcastle	1950
Darling Downs	Dalby	Brisbane	250
Darling Downs	Dalby	Newcastle	825
North-west NSW	Moree	Newcastle	550
Central West Orana	Wellington	Newcastle	375
North-west Victoria	Warracknabeal	Geelong	325
Leigh Creek	Leigh Creek	Adelaide	575

Note: distances calculated as walking distance with an additional 10% to allow for practical constraints on optimal pipeline route. RBP = Roma-Brisbane Pipeline; EGP = Eastern Gas Pipeline; MSP = Moomba-Sydney Pipeline; VNI = Victoria-NSW Interconnector; MAPS = Moomba-Adelaide Pipeline System.
Source: ACIL Allen analysis using Google Maps

Baseload plant power costs

For the ISP AEMO assumes that small-scale (notionally domestic) electrolysers need constant plant power supply equivalent to 4.5% of the rated electrolyser capacity, and large-scale (notionally export-oriented) electrolysers require 2% of the rated electrolyser capacity. We consider these estimates to translate to very high loads for larger projects and so have adjusted the assumptions such that our unfirmed hydrogen production are assumed to draw a constant load equivalent to 2% of rated electrolyser capacity and our larger firmed production sites draw a constant load of 1% of rated electrolyser capacity.

We have used ACIL Allen *PowerMark* modelling to estimate baseload electricity costs for the spot years modelled (Table C.4). We have not made specific allowance for transmission, retail or green scheme costs – these will be small compared to wholesale power costs for flat consumption of the scale modelled here.

Table C.4 Baseload power price assumptions (2023 $/MWh)

Year	QLD	NSW	VIC	SA
2029-30	$76	$91	$92	$93
2039-40	$119	$112	$119	$112
2049-50	$122	$116	$126	$122

Source: ACIL Allen PowerMark modelling

[23] GPA 2022, Pipelines vs powerlines: a technoeconomic analysis in the Australian context, https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/pipelines_vs_powerlines_-_a_technoeconomic_analysis_in_the_australian_context.pdf.

Baseload plant power comprises about 3% of the cost of firmed hydrogen production in our modelling.

Water costs

We adopt water cost assumptions from Aurecon's analysis in support of AEMO's ISP.[24] To be conservative we assume that plants will require dedicated desalination, to avoid competition with existing freshwater users. These assumptions indicate a cost of about $3 per kilolitre, which translates to cost of only about 6 cents per kilogram of hydrogen. Water is the smallest cost component we modelled, comprising just over 1% of hydrogen production cost.

C.1.2 Results

Figure C.1 presents ACIL Allen's modelled hydrogen production costs for three spot years: 2029-30, 2039-40 and 2049-50. Costs for years between these points are interpolated based on the implied compound annual growth rate.

— Queensland has the lowest cost of any region modelled, based on costs in the lowest-cost REZ, the North Queensland Clean Energy Hub.

— New South Wales' most cost-competitive supply option is based on production in the North Queensland Clean Energy Hub and pipeline transport to New South Wales

— Victoria has the highest cost of supply.

— All prices decline consistently over time to reach between $3.3 and $3.9 per kilogram (in real terms) by 2049-50, which is equivalent to about $21 to $28 per gigajoule.

Figure C.1 Firmed hydrogen production cost summary (2023$/kg)

Source: ACIL Allen analysis.

[24] Aurecon 2022, 2021-22 Cost and technical parameter review, https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/2021-cost-and-technical-parameters-review_rev3-21-march-2022.pdf?la=en.

C.2 Unfirmed hydrogen modelling methodology

ACIL Allen has modelling unfirmed hydrogen production as grid-connected, reflecting the generally small size of these projects (which are limited by the volume of demand for unfirmed hydrogen when blended into general natural gas supply).

Estimating the cost of unfirmed grid-connected hydrogen involves:

— analysing detailed (hourly) long-term projections of electricity prices across major electricity markets
— finding the cost-minimising load factor for electrolysers to minimise average production costs (lower load factors will increase per unit electrolyser costs but result in a lower average wholesale electricity purchase price, with the opposite being true for higher load factors.

We have modelled these prices for each NEM region and assumed that WA and NT unfirmed hydrogen prices will be similar to those in Queensland.

C.2.1 Key assumptions

Electricity prices

We have used ACIL Allen's *PowerMark* modelling to analyse hourly wholesale electricity prices across the five NEM regions for four spot years: 2024-25, 2029-30, 2039-40 and 2049-50. We ordered these prices into a series of prices increasing from smallest to greatest, to estimate how average wholesale electricity cost would increase with increasing electrolyser load factor.

Reflecting that these projects are grid-connected we included additional cost components to reflect transmission, retail and green scheme costs. These costs were estimated to be almost $25/MWh in 2024-25, reflecting ongoing costs from the LRET and SRES policies, before declining to $12.7/MWh in 2029-30 and $12/MWh in the long-run.

Electrolyser prices

As for firmed hydrogen production, we have used CSIRO's GenCost study as the basis of our estimate of alkaline electrolyser cost, and AEMO's ISP assumptions as the basis of our assumed electrolyser efficiency series.

Hydrogen and pipeline storage costs

We have assumed that unfirmed hydrogen does not involve any firming of hydrogen supply, and that the point of consumption or grid injection is very close to the point of production. For this reason, we have not assumed any hydrogen storage or pipeline costs for unfirmed hydrogen supply.

Baseload plant power costs

For the ISP AEMO assumes that small-scale (notionally domestic) electrolysers need constant plant power supply equivalent to 4.5% of the rated electrolyser capacity, and large-scale (notionally export-oriented) electrolysers require 2% of the rated electrolyser capacity. We consider these estimates can translate to very high loads, and so we have assumed baseload demand of 2% of rated electrolyser capacity.

As for firmed hydrogen supply, we used ACIL Allen *PowerMark* modelling to estimate baseload electricity costs for the spot years modelled.

Water costs

As for firmed hydrogen supply, we have adopted water cost assumptions from Aurecon's analysis in support of AEMO's ISP,[25] and assumed cost equivalent to that from desalination. Despite this relatively conservative assumption, water costs are a negligible component of overall hydrogen production cost, being about 6 cents per kilogram of hydrogen.

C.2.2 Results

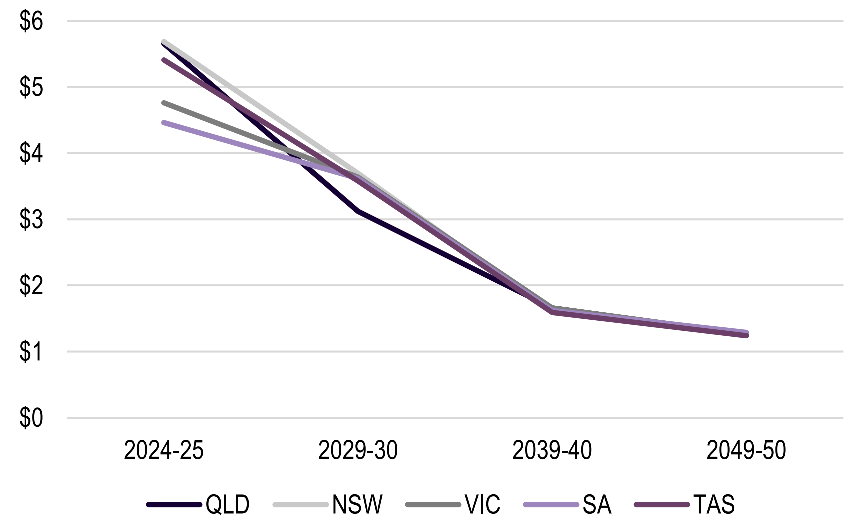
Figure C.2 presents ACIL Allen's modelled unfirmed hydrogen production costs for four spot years: 2024-25, 2029-30, 2039-40 and 2049-50. Costs for years between these points are interpolated based on the implied compound annual growth rate.

— South Australia initially has the lowest unfirmed hydrogen cost, reflecting the high prevalence of negative wholesale electricity prices in that state

— Prices across the NEM converge in the medium to long-term as widespread coal retirements reduce the prevalence of negative prices, and high solar penetration results in a high proportion of zero-priced periods, with the incidence of these periods being similar across all NEM regions

— The long-term price falls to very low levels of about $1.3/kg or about $9/GJ, reflecting the ability of small quantities of electrolysers to purchase zero wholesale electricity at zero cost for about 60% of hours across the year, and the significant decline of electrolyser costs.

Figure C.2 Unfirmed (volume-limited) hydrogen production cost summary (2023$/kg)



Source: ACIL Allen analysis.

[25] Aurecon 2022, 2021-22 Cost and technical parameter review, https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/2021-cost-and-technical-parameters-review_rev3-21-march-2022.pdf?la=en.

Optimal renewable gas target design

D

D.1 Policy context for a renewable gas target

Efficient emissions reduction is best achieved through a broad-based and technologically-neutral policy that provides equally strong incentives across all emissions sources and abatement actions. Theoretically, this is best achieved by internalising the social and environmental costs of carbon emissions through an emissions trading scheme or the imposition of a carbon tax across all sectors of the economy. Either approach would mean that individuals and companies incur a cost that reflects the environmental and social costs of carbon emissions these costs when producing carbon emissions and would have an incentive to reduce emissions when this was cheaper than the carbon price. However, Australia's complicated history with carbon pricing means that implementing such an approach is not likely to be politically feasible for the foreseeable future.

Instead, Australia's policy landscape is characterised by a mix of federal and state policies, providing incentives that vary significantly between sectors, technologies, use cases and locations. Despite the significant variation, this mix of policies is heavily focused on reducing emissions in the electricity sector, by supporting both electricity supply-side abatement and demand-side electrification. For example, the combined effects of the national Renewable Energy Target and a broad range of state-based renewable electricity support policies means that electricity users can confidently expect that emissions from their energy supply will progressively reduce over coming years. Similar policy effort has not been expended to transition natural gas users to renewable gas, and so these gas users do not have the same confidence that their energy supply will decarbonise over time.

A pivotal step to rebalance Australia's emissions reduction policies is to establish a renewable gas target (RGT). Such a target would kick-start supply-side abatement in the gas sector and give todays' gas users confidence that they will have viable low-emissions energy options in the future, similar to what the RET achieved for the electricity sector.

Taking a real options perspective also highlights the value of rebalancing Australia's abatement policy landscape. The fuel and capital cost trajectories of various low-emissions energy options are difficult to predict and what looks to be a dominant or obvious choice today may prove to be more expensive than expected. Instead, policy-makers should support a more extensive range of technology options, in which case emitters will be better placed to choose the best option for them as cost trends become clear and avoid locking in poor choices based on early trends or assumptions.

Box D.1 What is renewable gas

Renewable gases are gaseous fuels that can largely or entirely substitute for existing uses of natural gas in today's energy system. There are three types of renewable gases.

Biomethane

Biomethane is methane produced by anaerobic digestion (decomposition of organic matter by bacteria in an oxygen-free environment). Anaerobic digestion produces biogas a mix of methane, carbon dioxide and various impurities known as biogas. This biogas can be purified or 'upgraded' to biomethane by removing the carbon dioxide and impurities. Any carbon released to the atmosphere by venting unwanted carbon dioxide or burning biomethane still results in zero emissions over the fuel's lifecycle because the carbon was initially captured through the growth of organic material. Accordingly, biomethane can be considered renewable.

As methane is the main component of natural gas, once biogas has been upgraded to biomethane it is entirely substitutable for natural gas and compatible with existing infrastructure and appliances.

Green hydrogen

Green hydrogen is produced by decomposing water into its constituent molecules – hydrogen and oxygen – using renewable electricity. This process is known as electrolysis.

Hydrogen gas is substitutable for natural gas in various uses, including energy and feedstock (natural gas is often converted to hydrogen for use as a chemical feedstock, such as in ammonia production). Therefore green hydrogen can widely substitute for natural gas, though some infrastructure and appliances may require modification or replacement to accommodate the different chemical characteristics of hydrogen.

Renewable synthetic methane

Synthetic methane is produced by combining hydrogen and carbon dioxide in a process known as 'methanation'. When hydrogen and carbon dioxide are produced renewably the product is a renewable gas known as renewable synthetic methane. This methane is entirely substitutable for natural gas.

Green hydrogen production is discussed above. Renewable carbon dioxide production can occur in two main ways:

1. direct air capture, where carbon dioxide is captured from the air and the process is powered by renewable energy
2. organic carbon dioxide, produced by capturing carbon dioxide when upgrading biogas to biomethane or gasifying biomass.

Source: ACIL Allen

An RGT could be pursued through a legislated obligation on gas users to purchase renewable gas, analogous to the approach established through the RET. However, other mechanisms are possible and have been used in various contexts to support clean energy investment. Section D.2 below gives an overview of analogous policies in the Australian context, while Section D.3 considers the pros and cons of various policy options given Australia's stated policy objectives.

Section D.3 also identifies that a renewable gas purchase obligation analogous to the RET is the optimal policy option to implement an RGT. Section D.4 works through detailed policy design considerations for a renewable gas purchase obligation.

D.2 Australian experience with clean energy support policies

Australia has significant experience with policies that support various clean energy technologies, at both the national and the state level. Below we review the high-level features of a range of key policies to provide context for our consideration of policy options for an RGT.

D.2.1 Renewable Energy Target

The national RET was legislated in 2000 with an initial target of supporting 9.5 terawatt-hours (TWh) of new renewable electricity generation by 2010. The initial RET was legislated to cease in 2020. The target was subsequently amended three times.

— In 2009 it was increased to 45 TWh by 2020, which was chosen to target renewable generation equivalent to 20% of forecast national demand[26], with the scheme extended to 2030 to accommodate the target increase.

— In 2011 it was reduced to 41 TWh to reflect the shift of small-scale renewable electricity generation (principally rooftop solar) into a separate scheme.

— In 2015 it was further reduced to 33 TWh, reflecting in part lower electricity demand relative to the forecasts used in setting the 2009 target.

The RET operates by placing a renewable electricity purchase obligation on wholesale electricity customers participating in major grids. These liable customers can acquit their obligations by surrender of certificates created by recognised renewable electricity generators, and so the RET is commonly known as a ‘certificate scheme’. The trading of certificates creates competition between renewable generators and rewards liable entities that better manage their portfolio of renewable generation.

Despite the uncertainty created by various target changes, and fluctuations in certificate prices typical of these schemes, the RET has been effective in supporting investment and delivering its target. For example, investment under the RET slowed during 2014 and 2015 during the review of the target but responded quickly to meet the ultimate 2020 target of 33 TWh and has since continued to increase well above the mandated target level.[27]

Overall the RET has been very effective in achieving its objectives. Not only has the target been comfortably exceeded, but the architecture of the scheme has also provided the basis for widespread action from sub-national governments, corporations and households to purchase additional renewable energy and support abatement additional to the scheme. Familiarity with the RET appears to be a major reason why a broad range of stakeholders support the use of a comparable certificate scheme for an RGT.[28]

D.2.2 NSW Greenhouse Gas Abatement Scheme

The NSW Greenhouse Gas Abatement Scheme (GGAS) commenced on 1 January 2003 and was the first mandatory greenhouse gas emissions trading scheme in the world. Like the RET it took the form of a certificate scheme. NSW electricity retailers and large electricity users were liable under the scheme to purchase certificates representing greenhouse gas abatement achieved through a range of eligible abatement activities. These activities included:

— reduced emissions from existing generators (such as through upgrades that improved efficiency)

— new low-emissions electricity generation

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[26] This 20% national target included pre-existing renewable generators, principally hydro-electric generation. This pre-existing generation supplies about 15 TWh per year on average, and so the revised target implied renewable generation of about 60 TWh out of the then forecast 300 TWh of national demand by 2020.

[27] Clean Energy Regulator 2021, *The 2020 Renewable Energy Target annual statement – large-scale renewable energy target met*, https://www.cleanenergyregulator.gov.au/About/Pages/Accountability%20and%20reporting/Administrative%20Reports/Annual-Statement.aspx.

[28] Future Fuels CRC 2023, *Understanding the implications of a Renewable Gas Target for Australia’s gas networks*, p. 81.

— improved energy efficiency, including a range of activities with deemed efficiency improvements at the household level, such as the distribution of compact fluorescent light globes and low-flow showerheads
— sequestered carbon in forests
— reduced emissions from industrial processes and energy use.

GGAS closed on 1 July 2012 as the emissions reduction objective had been achieved (in part due to investment stimulated through the RET) and also because it was considered duplicative of the national carbon pricing mechanism that took effect at that time. Over 144 million certificates were surrendered over the life of the scheme,[29] nominally representing 144 million tonnes of carbon dioxide equivalent (tCO_2-e) abatement. However, uncertainties about the additionality of many activities credited under GGAS means that the scheme is likely to have achieved less abatement than this in practice.

Administrative costs of the scheme were modest. The scheme regulator, IPART, estimated administrative costs over the life of the scheme of about $18 million, or about 12.5 cents per certificate.[30] This excludes compliance costs of liable entities and abatement providers.

D.2.3 Queensland Gas Scheme

The Queensland Gas Scheme (QGS, sometimes referred to as the Queensland Gas Electricity Certificate Scheme or the GEC Scheme) commenced on 1 January 2005 with a target of ensuring that 13% of Queensland's electricity supply was generated using gas. The target was increased to 15% of electricity supply in 2010.

The scheme was created to support gas supply in Queensland, initially with a view to supporting investment in a proposed pipeline from Papua New Guinea, but later to support Queensland's rapidly emerging coal seam gas sector.

As with the RET and GGAS, the QGS was a certificate scheme that required liable entities (electricity retailers and wholesale customers) to acquit certificates representing eligible gas-fired generation.

The scheme was effective in achieving its objectives. Certificates traded near the scheme's penalty level from 2005 to early 2007, but then declined rapidly as drought conditions curtailed coal-fired generation (and therefore increased gas-fired generation), and as large-scale gas generators were committed to be built. By late 2009 certificates were trading at very low levels.

Around this time there was consideration of increasing the scheme target to 19%, but the operation of the national carbon pricing mechanism from 1 July 2012 and the success of the scheme in supporting gas-fired generation led the Queensland Government to close the scheme from the end of 2013.

D.2.4 Feed-in tariffs

During the late 2000s and early 2010s most states and territories in Australia implemented various feed-in tariff schemes to support small-scale solar generation. A feed-in tariff is a guaranteed minimum payment above general market rates, with a view to supporting investment.

These schemes varied in their design and longevity, but in general succeeded in supporting uptake of small-scale solar. However, they also typically created a boom-and-bust cycle of solar

[29] IPART 2013, *NSW Greenhouse Reduction Scheme: strengths, weaknesses and lessons learned*, https://www.ipart.nsw.gov.au/sites/default/files/documents/nsw_greenhouse_gas_reduction_scheme_-_strengths_weaknesses_and_lessons_learned_-_final_report_-_july_2013.pdf, p. 2.

[30] IPART 2013, *NSW Greenhouse Reduction Scheme: strengths, weaknesses and lessons learned*, p.10.

installations, with the generous feed-in tariffs creating elevated rates of installation, and a slump in investment following the schemes' closure. In this way, these schemes brought forward investment, as well as stimulating it.

The Australian experience demonstrates the simplicity and effectiveness of feed-in tariffs to stimulate investment, but also their inflexibility and their tendency to create a volatile investment environment characterised by boom-and-bust cycles.

D.2.5 Direct contracting

The NSW, Victorian and ACT governments have supported large-scale renewable generation through direct contracting, with these actions complementing incentives under the RET to support investment.

Each state has taken a slightly different approach:

— The NSW Electricity Infrastructure Roadmap sets out a plan for reverse auctions to support up to 12 GW of renewable electricity generation through Long-Term Energy Support Agreements (LTESAs). LTESAs provide a floor price to successful tenderers to reduce their investment risk, rather than a firm offtake price. The NSW Government recently announced results of the first reverse auction, representing about 1,400 MW of renewable generation.

— The Victorian Renewable Energy Target policy established reverse auctions to support renewable electricity generators through long-term contracts that establish a fixed strike price (sometimes referred to 'contracts-for-difference', as payments are made by reference to the difference between the prevailing market price and the contract strike price). The first VRET auction supported 800 MW of wind and solar generation to target 40% renewable generation in the state by 2025, while the second auction supported 600 MW of solar generation to offset emissions from the State Government's own electricity use.

— The ACT's reverse auction policy supported about 600 MW of large-scale renewable generation across the National Electricity Market to notionally supply 100% of the ACT's electricity consumption. As with Victoria, payments to these generators were delivered through long-term contracts-for-difference.

The Victorian and ACT policies are substantially complete and have been effective in achieving their objectives (though projects under the second Victorian auction are yet to be commissioned).

The NSW policy is only at its early stages and so its long-term effectiveness cannot be meaningfully assessed.

D.2.6 NSW Renewable Fuel Scheme

The NSW Government's 2019 Hydrogen Strategy set out a target to develop 8 PJ of hydrogen production within the state by 2030. To achieve this the NSW Government has legislated to create the Renewable Fuel Scheme (RFS), which is a certificate scheme established under the *Electricity Supply Act 1995* in parallel to other similar NSW certificate schemes (the Energy Savings Scheme and the Peak Demand Reduction Scheme, which incentivise energy efficiency and peak demand reductions respectively).

The RFS has not yet commenced and does not have fully detailed rules in place to support the scheme's operation. However, the legislation does establish that gas retailers and large gas users will be the liable entities under the scheme, and that green hydrogen will be an eligible renewable fuel (with the potential for the Minister to establish other eligible renewable fuels through regulations).

D.2.7 WA Hydrogen target

In December 2022 the WA Government announced its intention to develop two hydrogen target certificate schemes:

— An initial scheme focused on electricity generation in WA's South-West Interconnected System, with an indicative target of 1% of generation from green hydrogen

— A subsequent broader scheme to support green hydrogen use across all potential applications, including process heat, feedstock and road transport.

The WA Government is consulting on the design of the hydrogen electricity target scheme. An early consultation paper indicates that the scheme will place liability to purchase certificates representing eligible hydrogen electricity generation on electricity retailers and large customers.[31]

D.3 Policy objectives and assessment of preferred policy option

D.3.1 Policy objectives

Reflecting the context set out in section D.1 the overall purpose of an RGT is to allow renewable gas to compete on a more equal footing with renewable electricity as a viable low-emissions energy option, rebalancing the policy landscape and giving gas users the option to decarbonise without electrification. Therefore, we consider that an RGT should be designed to achieve two primary policy objectives.

— **Reduce emissions.** Renewable gas should be developed as it can make both short-term and long-term contributions to reducing emissions in Australia.

— **Develop the renewable gas industry**. Australia's renewable gas industry is relatively immature, with biomethane development in particular being significantly behind that in Europe and North America. Australia must develop skills and adapt imported technology to local feedstocks and conditions to rapidly take-up renewable gas. This won't be easy to achieve without strong and sustained policy incentives.

An RGT can also contribute to a range of other objectives, though these are secondary to the two discussed above.

— **Improve energy security**. Developing new and diverse energy sources based on local feedstocks and electricity supply can improve energy security. Today's gas supply is based on a handful of large gas sources, which brings a degree of supply risk when major facilities have technical issues. An RGT can develop a new renewable gas supply industry that is likely to be based on many smaller supply points, diversifying supply and reducing critical event risk.

— **Build new demand-side industries**. Australia's rich renewable resources offers the prospect of developing a range of new industries based on the intensive use of zero-emissions energy. Many of these industries depend on renewable gases, including hydrogen and hydrogen-derivative exports, and the reduction of iron ore to green iron using hydrogen. An RGT can develop the skills and supply-side industry to support these new demand-side industries, unlocking significant export-oriented economic opportunities for Australia.

[31] WA Government 2022, *Renewable hydrogen target for electricity generation in the SWIS*, https://www.wa.gov.au/system/files/2022-10/EPWA-Renewable%20Hydrogen%20Target%20for%20Electricity%20Generation%20in%20the%20SWIS-Consultation%20Paper_0.pdf, p. 14.

D.3.2 Multi-criteria analysis framework for assessing preferred policy option

We have developed a multi-criteria analysis (MCA) framework to analyse the merits of various RGT policy designs. This framework prioritises actions that target our two primary policy objectives: emissions reduction and renewable gas industry development.

Table D.1 Multi-criteria analysis framework

Criterion	Weighting	Evaluation of criterion	Objectives targeted
Effectiveness	30%	Does the scheme offer high confidence that it will achieve the targeted emissions reduction objective?	Emissions reduction
Economic efficiency	30%	Is the scheme designed to achieve the emissions reduction objective in an economically efficient way, and so ensure that the scheme is economically and politically sustainable?	Emissions reduction
Investability	20%	Does the scheme provide investors with sufficient certainty to underpin renewable gas investment?	Renewable gas industry development
Simplicity and administrative feasibility	20%	Is the scheme design simple to establish with low risk of unintended consequences arising in implementation?	Emissions reduction and renewable gas industry development

Source: ACIL Allen analysis

D.3.3 Multi-criteria analysis of potential policy options

ACIL Allen has identified four primary policy options to drive the achievement of an RGT:

— **A certificate scheme.** A government places a renewable gas purchase obligation on gas market participants, with compliance demonstrated through the surrender of certificates created by eligible renewable gas producers (hence a 'certificate scheme').

— **Direct contracting.** A government or government authority contracts with renewable gas producers at prices sufficient to underpin investment and production. Typically contracts would be determined through a competitive reverse auction, so these schemes are sometimes referred to as reverse auction schemes. Costs would be recovered from consumers or governments.

— **Feed-in tariff.** A government sets a mandated minimum payment rate for renewable gas production to support investment and production, with costs recovered from consumers or governments.

— **Direct funding support.** A government provides direct budgetary funding to renewable gas producers to support investment and production.

Below we assess each policy option against the four assessment criteria to determine an overall ranking of the policy options.

Table D.2 Assessment of policy options against criteria

Policy option	Discussion	Rating (out of 5)
Effectiveness		
Certificate scheme	A certificate scheme establishes a purchase obligation that precisely reflects the renewable gas target level. This gives high confidence in achieving the policy target, particularly if the scheme is established in legislation. In general, by directly targeting the policy objective in terms of volume of renewable gas	5

Policy option	Discussion	Rating (out of 5)
	uptake and allowing the price of certificates to vary to achieve this target, certificate schemes are likely to prove highly effective.	
Direct contracting	Governments can undertake multiple auction rounds to calibrate the contracted volume to achieve the renewable gas target level. However, each auction round is subject to budgetary and policy decisions, and contracted projects may be delayed or cancelled. Residual risk remains that this mechanism will fail to achieve the policy target.	4
Feed-in tariff	The feed-in tariff payment level must be set in advance, creating a risk that it will be set at too low a level to achieve the policy target. While the rate could then be adjusted, regular changing of the feed-in tariff would create investor uncertainty and undermine the broader effectiveness of the scheme. In general, it is difficult to use a fixed price feed-in tariff effectively target a specific volume of low-emissions energy uptake.	4
Direct funding	Governments can undertake multiple grant rounds to attract sufficient investment to achieve the renewable gas target. However, each grant round is subject to budgetary and policy decisions. Further, it is difficult to structure grant programs to protect against the risk of project delays and cancellations, creating a material risk that the mechanism will fail to achieve the policy target.	3
Economic efficiency		
Certificate scheme	A purchase obligation is a market-based mechanism that creates competitive tension between renewable gas producers and engages the market knowledge of liable customers to identify suitable projects and credible project proponents. This competitive market-based process supports both allocative efficiency (identifying the markets where renewable gas is most competitive) and productive efficiency (driving cost-efficiency from producers).	5
Direct contracting	Direct contracting typically involves price-based competition between potential providers, but this is limited to the specific requirements determined by each government allocation round. While this supports productive efficiency, it does not necessarily achieve allocative efficiency because governments are not well-placed to identify the commercial value of renewable gas in different markets. For example, natural gas is cheaper in WA than in eastern Australia, in which case an eastern Australian renewable gas project may offer better value than a WA project with lower production cost. In general terms, such a mechanism is not truly market-based as producers can only compete with each other on the terms specified by the government, without necessarily creating an industry that can sustainably compete in the wider energy market.	4
Feed-in tariff	The feed-in tariff payment must be set in advance, creating a risk that it will be set at a level above that needed to meet the target. In that case it will support a range of high-cost (productively inefficient) projects, and undermine dynamic efficiency (by front-loading project development, which precludes later projects that may have benefited from innovation and industry learning).	2
Direct funding	Governments may struggle to assess the true commercial value of projects at arms-length, and so select inferior projects and undermine allocative efficiency. Government grant rounds also suffer from the political need for early commitment, locking the funder into supporting specific projects despite cost over-runs or delays and so undermining productive efficiency.	2
Investability		
Certificate scheme	The financial incentive created by selling traded renewable gas certificates is uncertain and subject to competitive forces. This creates some risk and uncertainty for investors, reducing investability (but increasing efficiency incentives, as discussed above). However, the creation of a mandatory market for renewable gas provides an ongoing investment incentive, creating a	4

Policy option	Discussion	Rating (out of 5)
	significant opportunity for investors to undertake multiple investments that capitalise on the market and technical knowledge developed through early projects.	
Direct contracting	Government contracting provides a high degree of revenue certainty for investors, and a high level of investability. However, the need for budget funding creates uncertainty about the timing and value of future contracting rounds, reducing the scope for multiple investments that build on the knowledge developed through early projects.	4
Feed-in tariff	Government mandating a fixed price gives a high degree of revenue certainty and a high level of investability. However, the risk that the initial feed-in tariff will be set at an overly-generous level creates a risk that it will be reduced over time, reducing the scope for multiple investments that build on the knowledge developed through early projects.	4
Direct funding	Grant recipients enjoy a strong level of government support to invest. However, the need for budget funding creates uncertainty about the timing and value of future contracting rounds, reducing the scope for sequential investments that build on the knowledge developed through early projects.	4
Simplicity/administrative feasibility		
Certificate scheme	A certificate scheme is relatively complex, requiring high quality regulatory oversight and robust compliance and trading systems. However, Australia has experience with such schemes through similar schemes such as the RET, GGAS and QGAS, and existing capabilities and systems that can be readily adapted to support a renewable gas scheme.	3
Direct contracting	Direct contracting is relatively simple, although governments must protect themselves against the risk of delayed or cancelled projects through a range of due diligence checks and assessment gateways, creating some complexity.	4
Feed-in tariff	A feed-in tariff is relatively simple to administer, but it requires a settlement architecture to ensure that projects are paid appropriately and sufficient funds are raised from consumers (or governments) to make these payments.	5
Direct funding	Grant funding is relatively simple, although governments must protect themselves against the risk of delayed or cancelled projects through various due diligence checks and assessment gateways, creating some complexity.	4

Source: ACIL Allen analysis

Based on the assessment in Table D.1 the optimal RGT policy option is a certificate scheme:

1. A certificate scheme achieved a weighted rating of 4.4 out of 5 in our MCA, with high scores (5 out of 5) for effectiveness and economic efficiency.
2. Direct contracting ranked second in our MCA, scoring 4.0 out of 5. It scored good ratings (4 out of 5) on all criteria but is likely to be less effective and efficient than a certificate scheme.
3. A feed-in tariff ranked third in our MCA, scoring 3.6 out of 5. This option is likely to be quite effective and support investment, and is the simplest option to administer, but can lead to economically inefficient outcomes.
4. Direct funding is the weakest policy option, scoring 3.1 out of 5. The reliance on periodic government funding creates uncertainty on the long-term effectiveness of the policy, as well as uncertainty for investors. This approach also is likely to create distorted incentives that undermine economic efficiency.

Key Finding 1 Optimal policy option

A certificate scheme placing a renewable gas purchase obligation on gas market participants is the optimal policy option for achieving a renewable gas target.

D.4 Detailed RGT certificate scheme design

Choosing a certificate scheme as the optimal RGT policy option necessitates a range of detailed policy design considerations. This section sets out the key elements of our proposed optimal RGT certificate scheme (hereafter referred to as a renewable gas scheme or the 'scheme').

D.4.1 Target setting

The long-run target level

A key element of a renewable gas scheme is the long-run or ultimate level of the RGT itself. Without a target that is materially above business-as-usual expectations, the policy will not drive significant abatement or additional investment.

The Australian Government has set a target of achieving net zero emissions by 2050.[32] In this context, one potential ultimate renewable gas target level is 100% of gaseous fuel consumption, which implies zero natural gas consumption. However, two factors indicate that this position may not be appropriate or necessary.

— A net zero target does not imply zero emissions from fossil fuels. It is possible to use offsets from carbon dioxide removal to net out emissions from, say, residual natural gas consumption beyond 2050 and still achieve net zero emissions.

— A renewable gas scheme is unlikely to be the only policy implemented that reduces gas consumption and emissions. For example, the Safeguard Mechanism requires large emitters to reduce emissions, and similar broad-based emissions reduction policies could be implemented to target net zero economy-wide. Given this, an RGT need not be designed to achieve the ultimate objective of net zero emissions, but should be seen as one policy in the broader policy portfolio. An RGT scheme would have a vital early role in driving renewable gas production and consumption in such a portfolio, but in the long-term it would work with other policies to deliver net zero emissions in the gas sector.

In this context, we consider that at least 90% of gaseous fuel consumption should be from renewable gases in the long-run. This allows 'headroom' for some natural gas consumption to continue with matching use of offsets to achieve net zero, while setting a strong and ambitious target for renewable gas production and ensuring that the gas sector does not excessively rely on offsets to reduce emissions.

This target represents a floor or minimum share of renewable gas use, not a ceiling or maximum. Suppose offsetting is a more expensive abatement option than further penetration of renewable gases. In that case, other policy incentives will likely drive renewable gas take-up above the long-run RGT level. This is evidenced by recent outcomes in the electricity sector, where policy and improving economics has seen the level of renewable electricity generation in Australia go well beyond the level mandated by the RET.

[32] *Climate Change Act 2022*, section 10(1)(b).

Key Finding 2 Ultimate renewable gas target level

The ultimate or long-run renewable gas target level should be 90% of gaseous fuel consumption.

Renewable gas target trajectory

A renewable gas target must ramp up over time to give industry sufficient time to invest in response to the policy. The optimal target trajectory is affected by several factors, and we expect that modelling the scheme will further inform this design element. These factors include:

— short-term constraints such as investment lead times, industry maturity and regulatory barriers
— policy decisions on the exemption of specific gas-using sectors (see section D.4.2, page D-12)
— choices on policy design elements that affect the cost to consumers of failing to achieve targets such as 'borrowing' certificates from the future for compliance and penalty levels (see section D.4.3)
— the need for the ultimate target level to be achieved and held for multiple years before the scheme ends to give later investments sufficient policy support (for example, the RET achieved its ultimate policy target in 2020 but will operate until 2030).

The scheme should start as soon as possible – indicatively 2025, but as soon as practically possible – as the need to develop this abatement option is urgent. However, some flexibility mechanisms may be needed before 2030 to defer early year liabilities as the scheme and the industry matures.

The scheme must operate for a long time to give sufficient time to develop large volumes of renewable gas. It should run until at least 2050 to provide enough time for the required level of investment to occur, and to align with Australia's net zero objective. A long-lived target will also give sufficient certainty to underpin investment in new capital equipment required for renewable gas production, such as anaerobic digesters, biogas upgraders and electrolysers.

We consider that the ultimate target should be reached by 2050, to ensure that the gas sector is contributing significantly to the Australian Government's objective of net zero by 2050. The ultimate target level should be maintained until 2060 to give late investments sufficient incentive to invest.

Key Finding 3 Target trajectory

The renewable gas scheme should:

start in 2025, or as soon as practically possible

involve some flexibility mechanisms for targets between 2025 and 2030 to give industry time to mature and invest to achieve the scheme

ramp the target strongly from 2030 to achieve the ultimate target by 2050

hold the target constant at the ultimate target level between 2050 and 2060.

Target specification

An RGT could be specified:

— as a fixed volume of energy (e.g. petajoules of consumption) representing the targeted renewable gas consumption share applied to forecast gaseous fuel demand
— as a fixed share of gaseous fuel consumption, such that the mandated volume of renewable gas consumption varies in line with changes in overall gaseous fuel consumption.

The electricity RET used the first approach, translating the targeted share of renewable electricity generation into a fixed volume of electricity production and consumption, expressed in gigawatt-hours in the legislation. This approach has the advantage of creating a fixed quantity of renewable gas demand for investors to supply but leaves a risk that gaseous fuel demand will grow significantly resulting in the share of renewable gas demand falling below the intended target level. Conversely, the second approach creates a risk falling gaseous fuel demand will reduce the required volume of renewable gas and harm the economics of new renewable gas projects, reducing investor confidence.

Reflecting these two risks we propose a hybrid approach.

— The core RGT should be expressed as a percentage of gaseous fuel demand, allowing it to flex upwards or downwards in line with overall gaseous fuel demand. This flexibility is necessary as there are potential futures where gaseous fuel demand increases significantly – for example through the development of new hydrogen-based industries – or where it decreases significantly – for example through widespread electrification.
— Renewable gas investors should be given some insulation from the risk of falling gaseous fuel demand by setting a fixed volume of renewable gas as a 'floor' target. This will be particularly important early in the scheme's life when the market is immature and financiers are unfamiliar with the renewable gas industry.

The target that applies in any given year would be higher of the core target or the translated floor target, unless the floor target translates to a target higher than 90%, in which case it would be 90% (as discussed above, capping the target at 90% gives the flexibility to use natural gas with offsets alongside renewable gas).

Key Finding 4 Defining the target

> The core renewable gas target should be expressed as a percentage of gaseous fuel demand to accommodate the significant uncertainty in future gaseous fuel demand.
>
> The renewable gas target should incorporate a fixed floor target, expressed as a volume of energy, to insulate early investors in renewable gases from the risk of falling gaseous fuel demand.

D.4.2 Scheme scope, eligibility and liability

Scope and segmentation

In several dimensions, scheme design can be broad and integrated, or more segmented (Table D.1).

Table D.1 Integrated versus segmented renewable gas target approaches

Scheme element	Integrated approach and examples	Segmented approach and examples
Geographic scope	National scheme with a single target	Multiple state-based schemes with separate targets
		National scheme with common state-specific targets
Renewable gas type	Single scheme target for all eligible renewable gases	Sub-targets for specific renewable gases
User type	Scheme target calculated on the basis of all liable users	Defined user sub-categories must achieve specific targets (could be a common target or differentiated)

Source: ACIL Allen analysis

In general more integrated approaches will be more efficient than segmented approaches. Segmenting the scheme target by geography, gas or user type will likely harm efficiency.

— Renewable gases will likely be more competitive with natural gas in some locations than others (for example, due to lower renewable gas production costs or higher prevailing natural gas prices). A single national target allows renewable gas production to be targeted to areas where it is most competitive, reducing cost compared to a segmented approach that requires all jurisdictions to achieve their share of a common national target. Separate state-based scheme will be even less efficient, as their targets and detailed design features will likely vary and so distort investment and increase administrative complexity.
— Requiring all eligible renewable gas types to contribute to meeting a target creates the risk of mandating investment into a portion of relatively expensive renewable gas types. It is more efficient to set a single scheme target for all eligible gases and allow different gas types to compete. This competition promotes both productive and dynamic efficiency.
— Segmenting targets by user types would distort uptake and complicate the scheme. While in the long-run all gas user types must transition to renewable gases (or move away from gaseous fuel), in practice this will be easier for some user types than others. For example, gas-powered generation may find it hard to transition initially, but then transition rapidly as hydrogen-compliant turbines become more widely available. User-segmented targets would impose costs by forcing early adoption of renewable gas in difficult use cases.

Key Finding 5 Scheme scope and segmentation

The renewable gas scheme should be as broadly-based and integrated as possible. That is, it should:

- have a single national target, rather than state-specific sub-targets
- apply equally to all eligible renewable gas types, rather than having gas-specific sub-targets
- apply equally to all gaseous fuel users, rather than having use case specific sub-targets.

Eligible renewable gases

In principle all renewable gases should be eligible to create certificates under the scheme and so contribute to satisfying the RGT. As set out in **Box D.1** the three main renewable gases are biomethane, green hydrogen and renewable synthetic methane.

To keep eligibility as broad as possible, and therefore reduce scheme costs through increased competition between potential renewable gas sources, we consider that biogas (the raw gas produced by anaerobic digestion) should also be eligible to participate in the scheme. However, the scope for use of unpurified biogas is relatively limited. It would need to be blended into pipelines in small quantities to comply with existing pipeline gas specifications, or alternatively could be used 'behind-the-meter' (we propose that behind-the-meter renewable gas use be included within the scheme, as discussed below on page D-17).

A key design element is the definition of green hydrogen, specifically, how the emissions profile of electricity production used in hydrogen production is estimated and treated. The Australian Government is developing a 'guarantee of origin' (GO) scheme to officially record the production processes and emissions associated with hydrogen production to underpin contracting. A consultation paper released in December 2022 proposed replacing the RET's accounting framework post-2030 with a similar market-based framework underpinned by 'Renewable Electricity Guarantee of Origin' (REGO) certificates.[33] Under this framework, a hydrogen producer

[33] Australian Government 2022, *Renewable electricity certification: policy position paper for renewable electricity certification under the Guarantee of Origin scheme and for economy-wide use*,

would surrender REGO certificates equivalent to its electricity consumption to qualify as green hydrogen, at which time the producer would create a 'product GO' certificate to support the sale of that green hydrogen to a customer. Adopting a parallel accounting framework for our proposed renewable gas scheme would be complex and confusing, so it should be designed to be consistent with the national GO framework once finalised (in other words, surrendering REGO certificates should be sufficient to establish that hydrogen production is renewable, and therefore to create a certificate under the renewable gas scheme).

We have assumed that 'blue hydrogen' (Box D.1) is not included within the scheme because:

— it is not renewable
— it is unlikely to reduce emissions to the same extent as other renewable gases, due to imperfect carbon capture.

Box D.1 What is blue hydrogen?

Blue hydrogen refers to hydrogen produced from fossil fuel feedstock where carbon capture and storage is used to significantly reduce the net emissions created from its production.

The two most common production methods are steam reformation of natural gas and coal gasification.

Source: ACIL Allen

Key Finding 6 Eligible renewable gas types

The scheme should define biomethane, green hydrogen and renewable synthetic methane as eligible renewable gases.

The definition of green hydrogen should be based on the acquittal of official renewable electricity generation certificates, consistent with the Australian Government's proposed hydrogen Guarantee of Origin scheme.

Biogas should also be eligible to participate, provided 'behind-the-meter' gaseous fuel consumption is suitably treated within the scheme design (see Key Finding 9).

We have assumed that blue hydrogen is not included as it is not renewable and would generally not be able to achieve the same emissions reductions as other renewable gases.

Liability

In general, broader scheme liability will better achieve the scheme's primary objectives of emissions reduction and renewable gas industry development, by creating an incentive for more gas end users to take up renewable gas and creating a larger market for renewable gas.

One important exclusion is exported natural gas. The scheme's objective is to reduce emissions within Australia and, consistent with typical international emissions accounting practice, emissions that occur in other countries are out of scope. Consistent with this, natural gas exports should be considered out of scope and so should not incur a liability to purchase renewable gas under the scheme. However, gas used to process natural gas for export is counted in Australia's emissions profile and must ultimately be decarbonised, so this gas use should be liable.

Further, if renewable gas is eligible to create certificates under the scheme, the consumption of this gas should also be treated as liable under the scheme. This reduces the risk that some users will gain a benefit under the scheme by selling certificates without any associated obligation.

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https://storage.googleapis.com/files-au-climate/climate-au/p/prj232e2205fdfa8b85770e8/public_assets/Policy%20position%20paper%20%20-%20%20Renewable%20Electricity%20Certification.pdf.

There are also practical considerations that affect how liability is defined and managed. The three main choices for which entity should be liable are:

- wholesale gas customers, including both retailers who buy gas on behalf of smaller users and large users who directly participate in wholesale gas markets
- gas networks, whose primary role is to transport gas to end users
- wholesale electricity customers, including both retailers and large users.

We do not consider that placing liability on electricity customers is appropriate for two main reasons.

- It would result in the costs of stimulating renewable gas production being placed on many entities that do not benefit from this production, specifically electricity users that do not consume gaseous fuels.
- It would distort the abatement incentives of both electricity and gas users, and so reduce the allocated efficiency of the scheme. In principle, electricity users should pay for the costs of reducing emissions from electricity supply, and gas users should pay those costs for gas supply. When these costs are internalised in the prices of these energy sources, users can make efficient decisions on which fuel offers the best decarbonised energy source for their specific needs. If costs of decarbonising gas are placed on electricity users, these decisions would be biased towards gas use and distorted.

We prefer liability being placed on wholesale gas customers, for three main reasons:

- The electricity RET places liability on wholesale electricity customers, and hence many Australian energy market participants are familiar with this model.
- Wholesale gas customers are active gas market participants, and so are better placed to manage the liabilities associated with the scheme and make commercial decisions on the competitiveness of renewable gas supply options than are networks.
- Not all large gas users are supplied by gas networks with, for example, several large LNG plants undertaking their own production and processing operations (and pipeline transport between them) as a single integrated facility with no recognised gas network involved. Placing liability on gas networks would inadvertently exempt some large users from the scheme and could distort future infrastructure ownership decisions (for example, it would bias against using third-party pipeline infrastructure to connect gas production and liquefaction facilities).

In general, liability for network-connected users can be managed through the same processes that wholesale gas customers manage pipeline withdrawals. Where retailers purchase wholesale gas on behalf of network-connected small users, these retailers would face liability and, presumably, pass scheme compliance costs to small users. Where network-connected large users purchase wholesale gas networks they would be directly liable. To avoid double-counting gas that is traded multiple times in the wholesale market prior to final consumption, the scheme would need to specify that purchases are for the purpose of final consumption. In the RET this concept is known as a wholesale 'acquisition' so we use this term hereafter.

For the small number of non-network-connected gas users, practicality dictates that there should be a size threshold for liability. This threshold could reflect

- the cut-off for liability under the 2012-2014 carbon pricing mechanism of 25,000 tonnes of carbon dioxide equivalent (tCO_2-e), or about 0.5 petajoules of gas consumption
- the Safeguard Mechanism liability cut off of 100,000 tCO_2-e, or almost 2 petajoules of gas consumption.

As most stand-alone gas users are very large – for example, LNG facilities – the practical difference between these two positions is negligible. For consistency with the Safeguard Mechanism, we prefer a 2 petajoule cut-off reflecting about 100,000 tCO_2-e in emissions.

As renewable gas consumption is also liable under the scheme, large standalone renewable gas producing and consuming facilities will be liable. As with large standalone natural gas consuming facilities, such as LNG plants, a size threshold should apply to avoid inadvertently bringing small renewable gas facilities into the scheme and incurring high administrative costs. An example of such a small renewable gas facility would be a small-scale electrolyser suppling hydrogen for vehicle refuelling at a small depot. This threshold should be the same as for natural gas-consuming facilities, with 2 petajoules or more of consumption. Facilities below that size could opt into the scheme to monetise their excess renewable gas production.

Key Finding 7 Scheme liability

> All natural gas and renewable gas used within Australia should be liable under the scheme. Exported gas is not used within Australia and should be out of scope.
>
> Wholesale gas customers and users should be the liable entities under the scheme as they are best placed to manage scheme liabilities.
>
> Liable wholesale gas customers would be identified either based on their wholesale acquisitions of gas delivered through a gas network, or by identifying large non-network connected gas users that consume more than 2 petajoules of gas per year.

Exemptions

While liability should be broad in principle, there is a case for reducing the liability of some users to manage the expected scheme costs.

Existing Australian policy practice in the RET, and previously in the carbon pricing mechanism from 2012 to 2014, demonstrates a case for reducing emissions policy costs for emissions-intensive and trade-exposed (EITE) industries. This assistance was established to reduce the risk of disadvantaging Australian industry relative to international competitors, with the associated risk that production and emissions would shift from Australia to other jurisdictions and produce 'carbon leakage'.

Partial or complete exemption of EITE industries from the scheme is one way of achieving this objective. However, it is not the only approach. As EITE industries represent a large portion of Australia's gas consumption,[34] exempting these industries from liability would place a disproportionate burden on the remaining non-exempted sectors, particularly gas-fired power generation and residential gas users. As the RGT approaches the volume of non-EITE gaseous fuel consumption, it would become unviable to fully exempt EITE industries as it would require non-exempted entities to purchase more renewable gas than their total consumption.

Instead of exemption, other possible policy approaches include delayed inclusion in the scheme (with early renewable gas targets being lower to reflect the reduction in liable gas consumers within the scheme), or full inclusion in the scheme combined with direct budgetary support to reduce the cost burden of the scheme. Irrespective of the specific RGT design option adopted, most EITE industries would retain strong abatement incentives to reduce emissions under the Safeguard Mechanism.

[34] Initial analysis indicates that gas use by the LNG (own-use only), alumina, ammonia and steel industries alone is about 42% of Australian domestic natural gas consumption. As there are other EITE industries it is likely that EITE gas consumption exceeds 50% of national consumption.

Key Finding 8 Exemptions

It is unlikely to be viable to exempt emissions-intensive trade-exposed industries in the medium- to long-term under a renewable gas scheme, due to the high proportion of such loads amongst gas users. Other policy options available in finalising a renewable gas scheme include delayed inclusion in the scheme and direct budgetary support to reduce the scheme's impact.

Liability and eligibility carve-outs

As set out in Key Finding 7, wholesale gas customers that acquire gas delivered through gas networks and large non-network gas users with more than 2 petajoules of gas consumption should be liable.

However, a few complex cases require accommodation with the liability rules. Consistent with our general approach of making renewable gas both eligible and liable under the scheme, any adjustments to liability should be mirrored in our approach to eligibility. This reduces the risk that some users will gain a benefit under the scheme by selling certificates without any associated obligation, or conversely that some users will face liabilities under the scheme without an associated benefit.

Two main 'boundary cases' raise questions about how this principle should be applied:

— When a user uses a combination of gas supplied via network (which is liable) and renewable gas supplied 'behind-the-meter' (BTM), should the BTM supply be eligible to create certificates and also included in the calculation of liable gaseous fuel consumption?
— Should a standalone (non-network) facility that relies entirely or largely on renewable gas be liable under the scheme and eligible to create and sell certificates?

Treatment of behind-the-meter supply

BTM supply is produced and used on-site, or produced nearby and supplied by a dedicated (non-network) pipeline. BTM supply is likely to come from renewable gas, such as on-site production and use of biogas or green hydrogen produced from localised electrolysers, so decisions on eligibility and liability are particularly important.

As discussed above on page D-13, broadening eligibility creates competition between more potential renewable gas sources, reducing costs and increasing scheme efficiency. For this reason, we consider that BTM supply should be eligible.

As a corollary, the principle discussed above dictates that the BTM fuel consumption should also be treated as liable consumption. Box D.1 uses a simple worked example to illustrate how this would work.

Box D.1 Worked example of behind-the-meter renewable gas supply

In this worked example we consider a food processing facility that uses 0.5 petajoules of natural gas per year from the local gas network and a further 0.5 petajoules of biogas per year produced behind-the-meter using an on-site anaerobic digester and a renewable gas target of 20%.

In this case both the grid-supplied and behind-the-meter supply are considered liable gaseous fuel consumption, and the facility's share of renewable gas consumption is 50% (0.5 petajoules out of a total of 1 petajoule).

As the renewable gas target is 20%, the food processing facility (or a retailer acting on its behalf in wholesale gas markets) would need to surrender certificates equivalent to 0.2 petajoules of renewable gas consumption (20% of 1 petajoule). Therefore, the food processor or its retailer (depending on contractual arrangements) would have 0.3 petajoules of renewable gas certificates that are excess to its needs, that it could 'bank' for future compliance or sell to other gas users.

Source: ACIL Allen analysis

Practicality and administrative costs may require that BTM production and consumption below a specific size threshold be included in the scheme on an opt-in basis. In any case, renewable gas producers are likely to be very motivated to be included in the scheme so they can register their production as eligible renewable gas and sell any excess certificates to other gas users

Standalone renewable gas consuming facilities

In the future Australia may have a number of standalone renewable gas producing and consuming facilities that do not rely on network gas supply. This could include green ammonia or green steel production using hydrogen supplied from dedicated electrolysers and piped directly to the production facilities.

We consider that these new facilities should be included in the scheme, as this will increase the potential sources of renewable gas and lower the overall cost of complying with the scheme. It will also support the secondary objective of the scheme of supporting new demand-side industries (see section D.3), as these facilities will typically have excess renewable gas certificates that they can sell to other liable entities to generate additional revenue streams.

However, if renewable gas producing and consuming facilities are included in the scheme it is necessary and appropriate to include both their production of renewable gas (which increases supply of certificates) and their consumption of gaseous fuels (which increases demand for certificates). The importance of this is illustrated by considering liability as the RGT approaches its ultimate level of 90%:

— If a renewable gas user can create certificates without any associated liability, it can sell certificates equivalent to its entire gas consumption. But only 10% of its renewable gas consumption exceeds the ultimate RGT of 90%.
— Conversely, suppose the user's gaseous fuel consumption is also treated as liable. In that case, the user will need to surrender 90% of its certificates to comply with the scheme's long-run target, and then, correctly, only has 10% of its certificates available to sell as excess to its requirements.

The difference between these two positions is not material when the RGT is at low levels but becomes significant as the target approaches the ultimate level of 90%.

Bringing large renewable gas-producing and consuming facilities into the scheme will cause the RGT to increase (as it is expressed as a percentage of gaseous fuel consumption), but the availability of renewable gas certificates will increase more proportionally, so it will make the RGT easier to comply with. This means that new renewable gas facilities will tend to 'dilute' the share of market supply from other producers and reduce the price of certificates. These effects are illustrated in the worked example below (Box D.1).

Box D.1 Worked example of new standalone renewable gas producing and consuming facilities

In this worked example we consider:

- the commissioning of a new standalone green ammonia facility that both produces and uses 10 petajoules of hydrogen per year
- a renewable gas target of 50%

In this case the facility can create 10 petajoules of renewable gas certificates and only has a liability to surrender 5 petajoules of certificates. This means that the facility has 5 petajoules of excess certificates to sell to other gaseous fuel users.

Regarding the effect on the national certificate market, we assume that gaseous fuel consumption was 1,500 petajoules and the market was positioned to achieve the annual target without the new green ammonia plant and so has supply of 750 petajoules of renewable gas.

In that case, the annual gaseous fuel consumption has increased to 1,510 petajoules, and the target has increased to 755 petajoules. But renewable gas supply has increased to 760 petajoules, so supply now exceeds demand and the excess 5 petajoules of renewable gas certificates can be banked for compliance in future years.

Source: ACIL Allen analysis

Including large renewable gas producing and using facilities in the scheme interacts with the Safeguard Mechanism in important ways. These interactions are discussed in further detail in section D.4.4 below.

Key Finding 9 Treatment of behind-the-meter and standalone renewable gas consumption

Behind-the-meter and standalone renewable gas production and consumption should be included within the scheme to increase the number of eligible renewable gas sources.

This production should also be treated as liable gaseous fuel consumption with an associated obligation to surrender a share of those certificates.

Practical considerations mean that it is likely to be appropriate to exclude smaller behind-the-meter or standalone renewable gas facilities. However, smaller facilities could opt into the scheme to monetise their renewable gas production in excess of the mandated target.

D.4.3 Other factors that affect efficiency, price and cost

Banking and borrowing

An important design element of a certificate scheme is intertemporal flexibility, or banking and borrowing – that is, the extent to which an entity's liability in a specific year can be met by certificates from an earlier year (banking) or deferred and met with certificates from a future year (borrowing).

Banking is a no-regrets measure and is typically allowed in analogous schemes without restriction. Suppose renewable gas producers can collectively ramp up production to exceed a given year's target. In this case, certificates from this year's excess production should be recognised and rewarded by allowing them to be banked against future liabilities. For example, the RET allows unlimited banking.

Borrowing is more controversial in the design of analogous schemes, illustrated by two potential issues discussed below:

— Borrowing could create a loophole to avoid liability, for example if an individual entity defers its liabilities and then subsequently goes bankrupt.
— A more fundamental issue can arise if numerous entities defer liabilities and then lobby policy-makers to write-off these liabilities or change the scheme design. Such a position would undermine the integrity and credibility of the scheme.

Borrowing should be somewhat restricted to avoid these issues. The RET imposes the following restrictions on how entities manage shortfalls.

— For a shortfall of less than 10% of their total liability, a liable entity can make up a shortfall within three years without penalty (in effect, a three-year borrowing provision).
— For shortfalls of more than 10% of their total liability, a liable entity must pay a cash shortfall charge for the component above 10%. This shortfall charge can be refunded if the entity subsequently achieves compliance.

The banking and borrowing provisions of the RET have supported the overall effectiveness of the scheme and we see no particular reason to adopt different requirements for a renewable gas scheme.

However, one exception is the need to give liable entities sufficient flexibility to comply with the scheme in its early years of operation. Given the need to rapidly ramp-up renewable gas production and the relative immaturity of the renewable gas industry in Australia, it is likely to be appropriate to give liable entities an extended borrowing window in the early years of the scheme, indicatively a five-year window from 2025 to 2029 inclusive. Shortfalls above 10% would be subject to a shortfall charge but entities could make up shortfalls and be refunded within five years, rather than three.

Key Finding 10 Banking and borrowing

The renewable gas scheme should broadly adopt the banking and borrowing provisions of the existing Renewable Energy Target, that is:

unlimited banking (early compliance)

limited borrowing (deferred compliance), with a shortfall charge applying to shortfalls of more than 10% and a period of up to three years in which to make good shortfalls.

The scheme should have an extended five-year borrowing window from 2025 to 2029 inclusive to give liable entities additional flexibility to manage risks when rapidly ramping up renewable gas supply.

Price protection and capping

It is possible that renewable gas supply will not be able to ramp to meet some interim targets, even with the flexibility provided by limited borrowing. Given this risk, the shortfall charge discussed above acts as an unofficial scheme price cap, with liable entities able to pay the shortfall charge in lieu of compliance. Therefore the level of this shortfall charge plays an essential role in managing the risk of acute spikes in the market price of certificates and has important risk management benefit for both gas users and renewable gas producers.

— The shortfall charge caps the overall exposure of gas users to scheme costs, mitigating the potential for extremely high costs.
— Renewable gas producers may enter into contracts that guarantee a particular supply volume, and face commercial penalties for non-delivery. The cost of these penalties can reasonably be the capped at the level of the shortfall charge, reducing the risk of renewable gas investments.

The size of the shortfall charge will need to be informed our modelling of the economics of renewable gas supply. The ultimate level of the shortfall charge should be set in a way that balances the need to provide significant incentive for renewable gas production and the risk to consumers of excessive scheme costs.

Key Finding 11 Capping scheme costs

Under the proposed borrowing provisions, the shortfall charge represents an unofficial price cap for the renewable gas scheme.

An appropriately-determined shortfall charge will balance the need to provide significant incentive for renewable gas production and the risk to consumers of excessive scheme costs.

D.4.4 Other issues and complexities

Interaction with Safeguard Mechanism

The Safeguard Mechanism imposes tightening baselines on the scope 1 (direct) emissions of large facilities emitting more than 100,000 tCO_2-e per year. Currently the scope 1 emissions from natural gas combustion can be calculated in three main ways:

— using generic combustion factors
— through direct sampling of gas composition
— through a combination of sampling and verification of commercial transactions.[35]

If facilities subject to the Safeguard Mechanism ('Safeguard facilities') are able to mix and match between these approaches, there is a risk that incentives under the renewable gas scheme and Safeguard Mechanism will lead to double-counting and 'leakage' of emissions away from Safeguard facilities to non-Safeguard facilities, reducing the efficiency and effectiveness of the scheme:

— Safeguard facilities may be able to claim 100% renewable gas operation based on commercial purchases of renewable gas, while still selling excess certificates under the renewable gas scheme – essentially creating a double benefit through both reduced Safeguard liabilities and revenue from the sale of certificates.
— Non-Safeguard facilities do not have a direct incentive to reduce scope 1 emissions and so will be happy to use generic factors or sampling approaches that assume 0% renewable gas.
— The overall effect will be that overall national emissions reductions in Safeguard facilities will be over-stated by the transfer of credit for renewable gas to those facilities.

While there may be a need for direct sampling to account for variations in gas quality at certain facilities, the best approach is likely to be adopting a nationally-consistent 'gaseous fuels' emissions factor, that reflects the blended emissions intensity of all gaseous fuels that are liable under the renewable gas scheme. This means that all entities contributing to decarbonising gas supply across Australia receive proportional credit through the emissions accounting framework.

This solves two main problems:

— The 'leakage' of emissions from Safeguard facilities to non-Safeguard facilities discussed above.
— Current arrangements could lead to inefficient outcomes. For example, a facility in one state could purchase certificates created from hydrogen injection into a network in another state, and Safeguard facilities connected to that network would get direct benefit from the reduced emissions intensity of their gas use estimated through the sampling approach (due to the

[35] Part 2.3 of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*.

higher hydrogen content).[36] So facilities would be subsidising the decarbonisation of other facilities, distorting incentives under both schemes.

Key Finding 12 Interaction with Safeguard Mechanism

Emissions from gaseous fuel use that is liable under the renewable gas scheme should be estimated for the Safeguard Mechanism using a generic national 'gaseous fuels' emissions factor, with this factor reflecting the national average blend of renewable and non-renewable gases.

This ensures efficient outcomes for all Safeguard Mechanism facilities and reduces the risk that commercial transactions will distort how the use of renewable gas is credited under the Safeguard.

Voluntary uptake of renewable gases

The use of a generic gaseous fuels emissions factor will ensure that increasing use of renewable gas has an even effect across a broad range of gas users (Key Finding 12). To ensure that this approach doesn't dilute incentives for gas users that want to go beyond the minimum mandated level of renewable gas, the renewable gas scheme and emissions accounting approaches should work together to recognise additional voluntary efforts.

For example, a user could surrender renewable gas certificates in excess of their liability as part of a broader corporate strategy to reduce emissions. In this event, emissions accounting under the National Greenhouse and Energy Reporting scheme (and therefore the Safeguard Mechanism) should reflect this voluntary surrender by adjusting that user's direct (scope 1) emissions to reflect their level of renewable gas consumption. In the limit, if a gas user surrendered certificates equivalent to their entire gas usage, their scope 1 emissions from that gas use should be zero.

Key Finding 13 Voluntary uptake of renewable gases

If gas users voluntarily surrender renewable gas certificates above the level mandated under the renewable gas scheme, this should be recognised as a reduction in scope 1 emissions for that user under the National Greenhouse and Energy Reporting scheme and the Safeguard Mechanism.

Baselining pre-existing facilities

The RET baselined pre-existing renewable electricity generators, principally hydro-electric generation, to avoid creating credits from existing generators that would continue to operate even in the absence of the policy.

The logic of baselining pre-existing facilities largely translates to a renewable gas scheme, as crediting pre-existing activities is unlikely to support additional renewable gas production, and therefore may not reduce emissions or develop the renewable gas industry.

However, a renewable gas scheme is being considered in a very different policy environment to that in which the RET was established. There were no material policy incentives for renewable generation prior to the RET, and so it was reasonable to assume that pre-existing electricity generators would continue to operate without any support from the RET. The same is not true of a renewable gas target, with some existing facilities receiving support through other policy mechanisms. The clearest case of this are biogas electricity generators that receive credit for their electricity output under the RET. If the RET closes as planned in 2030 and the renewable gas scheme baselines pre-existing biogas production, it is possible that output from these facilities will reduce due to a lack of sustaining investment.

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[36] This does not apply to biomethane as the methane in biomethane is handled the same as methane from natural gas under the physical sampling approach.

There are also practical issues with baselining. For example, biogas production is not always accurately metered, and so it may be difficult to establish a credible baseline.

Given these complexities, the issue of baselines for pre-existing facilities requires further consideration. At a minimum, if pre-existing facilities are not baselined, they should not be allowed to 'double dip' by drawing incentives from both the scheme and other policy measures (see Key Finding 15).

Key Finding 14 Baselining existing facilities

There may be a policy case to baseline pre-existing biogas or other renewable gas producers so that the renewable gas scheme only credits additional production.

However, this policy case is complex and requires further consideration. For example, baselining may not be feasible due to metering difficulties, and may not be appropriate if existing biogas facilities need sustaining investment beyond the life of the RET.

Interaction with other schemes

Today when biogas is burnt to generate electricity the responsible entity is eligible to create certificates under the RET.[37]

This creates a potential for 'double-dipping' if a renewable gas scheme comes into operation before the scheduled closure of the RET in 2030 and existing biogas production used for electricity generation is not baselined (see Key Finding 14). Double-dipping is most problematic for pre-existing facilities, as this does nothing to incentivise additional renewable gas production. This should be prevented through a simple double-dipping provision: if a pre-existing facility has created certificates under the RET it is not eligible to generate credits under the renewable gas scheme, or vice versa.

A somewhat similar risk of double-dipping also arises under state-based hydrogen support schemes such as the NSW Renewable Fuel Scheme (RFS) and the WA hydrogen target. The RFS sets a target of 8 petajoules of renewable hydrogen production by 2030 and holds that target constant from 2030 until the scheme closes in 2044[38] , while the WA scheme has an indicative target that 1% of electricity generation in the South-West Interconnected System should be from green hydrogen.[39]

However, as the investments supported by these schemes will, in most cases, not pre-date the RGT, the question of additionality can be handled differently. The simplest approach is probably to allow renewable gas production to be credited under multiple schemes (e.g. under both the RFS and RGT), but to explicitly adjust the national RGT level upwards to accommodate the established state scheme targets. This will ensure that the RGT will support additional investment beyond what those schemes require.

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[37] Section 17 of the *Renewable Energy (Electricity) Act 2000* defines the following potential sources of biogas as eligible renewable energy sources (without any restriction on whether they are burnt directly or processed through a process such as anaerobic digestion): energy crops, agricultural waste, waste from processing of agricultural products, food waste, food processing waste, landfill gas and sewage gas.

[38] *Electricity Supply (General) Regulation 2014 (NSW)*, section 63.

[39] WA Government 2022, *Renewable hydrogen target for electricity generation in the SWIS*, https://www.wa.gov.au/system/files/2022-10/EPWA-Renewable%20Hydrogen%20Target%20for%20Electricity%20Generation%20in%20the%20SWIS-Consultation%20Paper_0.pdf, p. 14.

Key Finding 15 Interaction with other schemes

> Pre-existing facilities should not be allowed to create certificates under both the renewable gas scheme and the RET to avoid 'double-dipping'.
>
> New facilities would be allowed to create facilities under multiple schemes, as would likely occur, for example, under the NSW Renewable Fuel Scheme or the WA hydrogen target. However, the national renewable gas target should be adjusted upward to accommodate these schemes and ensure that the national scheme brings forward additional production beyond what is required under state-based schemes.

Interaction with technical regulation

Hydrogen has different chemical characteristics to methane, and so it faces greater pipeline and appliance compatibility issues than biomethane and renewable synthetic methane. A complex hierarchy of rules govern the injection of gases into pipelines and compatibility with appliances, including:

— The National Gas Law and Rules, which apply primarily to the economic regulation of pipelines

— State-based safety regulations applying to the operation of pipelines

— Australian standards applying to specific gas-using appliances.

The need to ensure compatibility with pipelines and appliances, including compliance with relevant regulations and standards, will increase the cost of hydrogen blending relative to biomethane and renewable synthetic methane, disadvantaging hydrogen production. This will be especially true when hydrogen blends are injected into large volume pipeline mains serving larger industrial and commercial gas users, as the compatibility of hydrogen blends with larger gas appliances needs to be assessed on a case-by-case basis.

There is no need for the renewable gas scheme to explicitly manage or anticipate the costs and constraints imposed by safety regulation and appliance compatibility. If hydrogen producers cannot find pipelines willing and able to accept their product, then investors will need to increase supply of biomethane, renewable synthetic methane and behind-the-meter hydrogen or biogas, or facilitate the development of new pipelines to achieve the RGT. Behind-the-meter use of hydrogen is an important way to work around pipeline blending constraints as it can directly target individual users with more hydrogen-compliant appliances, or who are willing to invest to adapt their appliances to take hydrogen.

Key Finding 16 Technical regulation of hydrogen

The renewable gas scheme does not need to make specific allowance for the technical regulation of hydrogen to ensure compatibility with pipelines and appliances. This compatibility is assessed and achieved through other mechanisms.

Summary of sensitivity analysis E

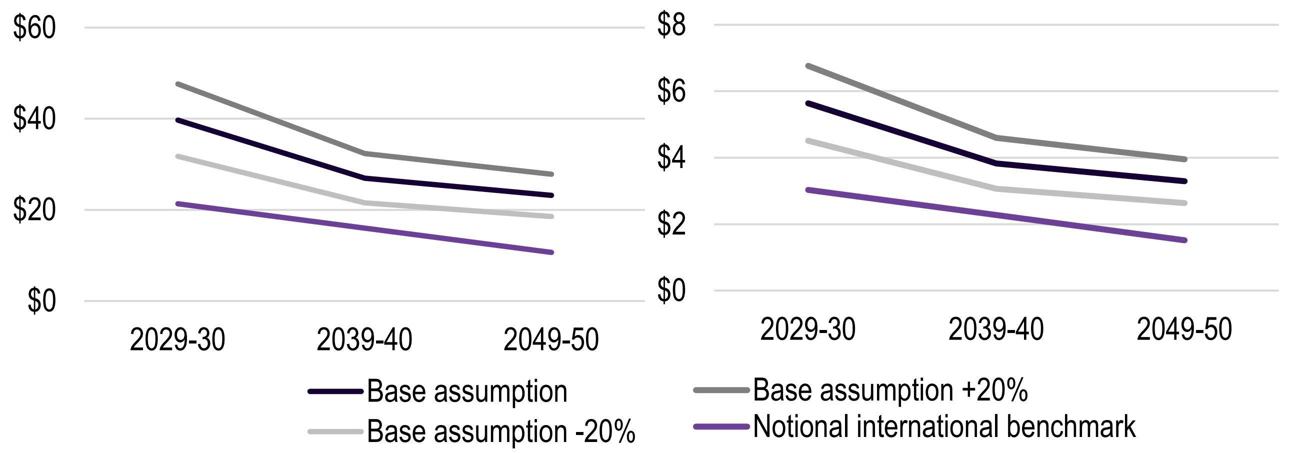
This appendix summarises results for the six sensitivities that vary assumptions from the core assumptions adopted in the modelling scenarios:

- Hydrogen Cost sensitivity
- No Biomethane sensitivity
- High Renewable Gas sensitivity
- High Electrification sensitivity
- High Hydrogen sensitivity
- High Biomethane sensitivity.

For each sensitivity, we present three figures below that show the change in fuel mix for the sensitivity relative to the Theoretical Efficient Policy scenario, the gaseous fuel share for each sector for the sensitivity compared to the Theoretical Efficient Policy scenario, and the detailed fuel and appliance mix at a detailed activity level.

The hydrogen cost assumptions used in the various sensitivities are summarised in Figure E.1. This illustrates that we have tested a range of potential hydrogen costs, but our lower hydrogen cost assumptions remain above the widely-discussed international green hydrogen cost benchmarks of USD2/kg in 2030 and USD1/kg in 2050.

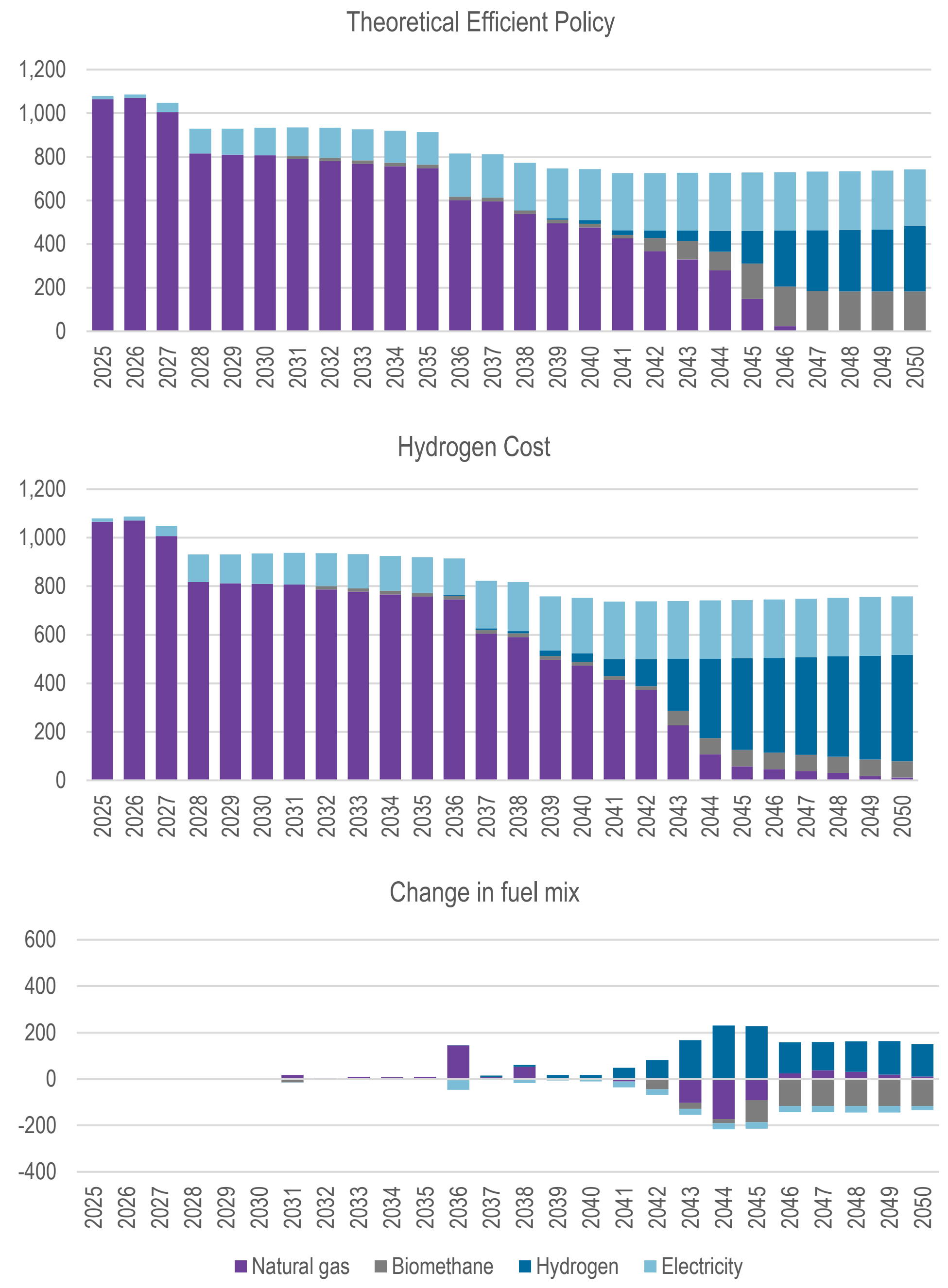
Figure E.1 Queensland firmed hydrogen production cost, by scenario and sensitivity: ($/GJ, LHS; $/kg, RHS)



Note: the notional international benchmark is based on hydrogen cost of USD2/kg in 2030 and USD1/kg in 2050, converted to AUD at an exchange rate of 0.66 USD:AUD.

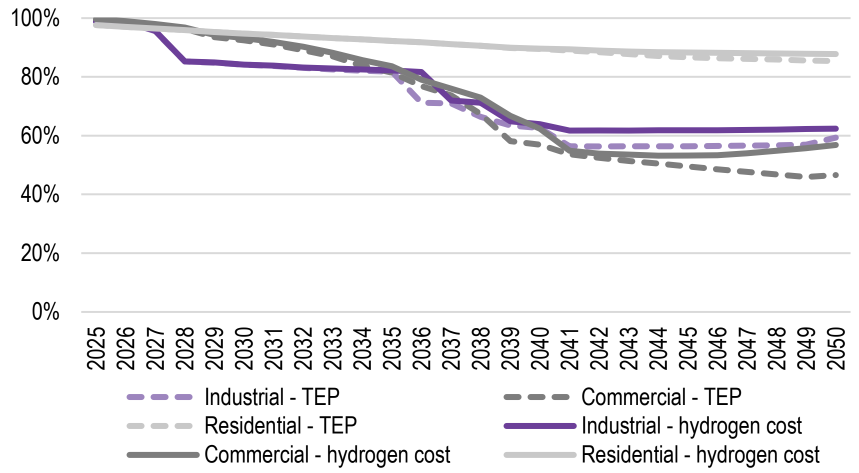
Source: ACIL Allen analysis

Figure E.2 Fuel mix (PJ): Theoretical Efficient Policy scenario, Hydrogen Cost sensitivity, and change between Theoretical Efficient Policy scenario and Hydrogen Cost sensitivity



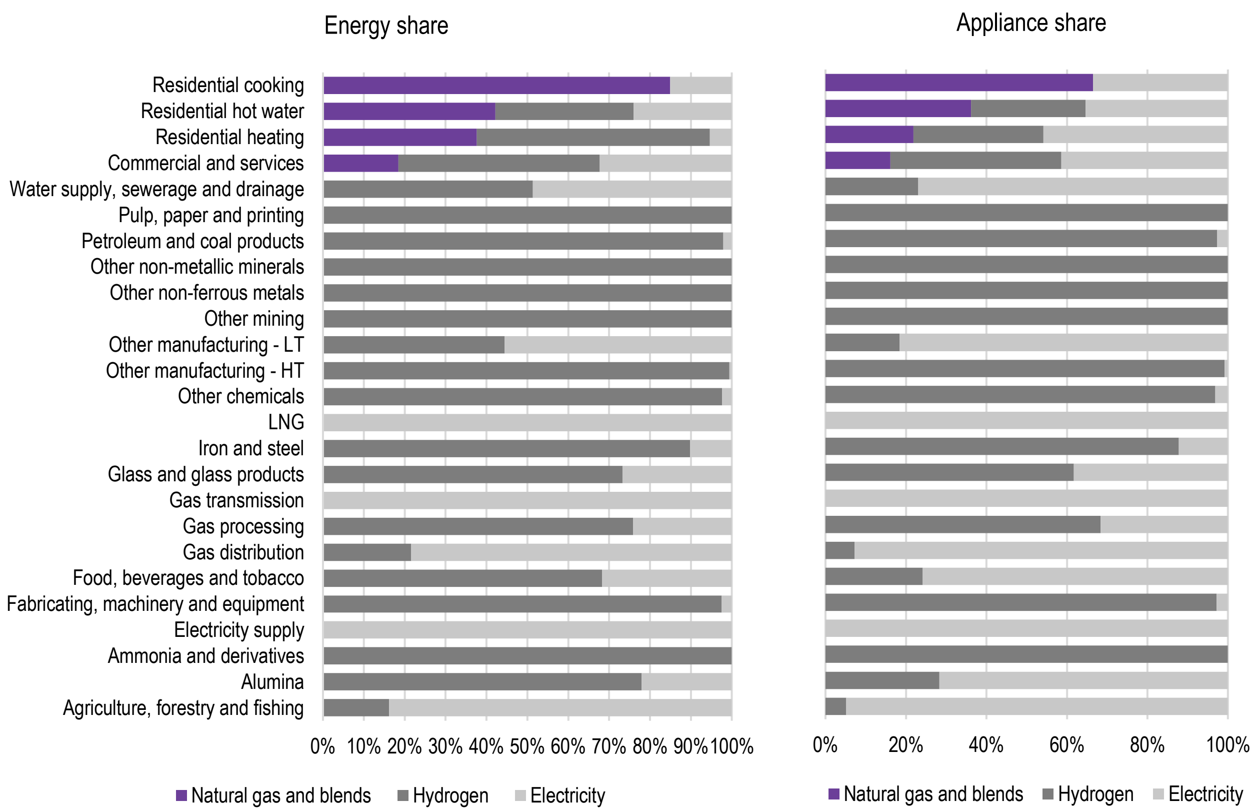
Source: Gas Transition Model

Figure E.3 Gaseous fuel share (%), by sector: Hydrogen Cost sensitivity compared to Theoretical Efficient Policy scenario



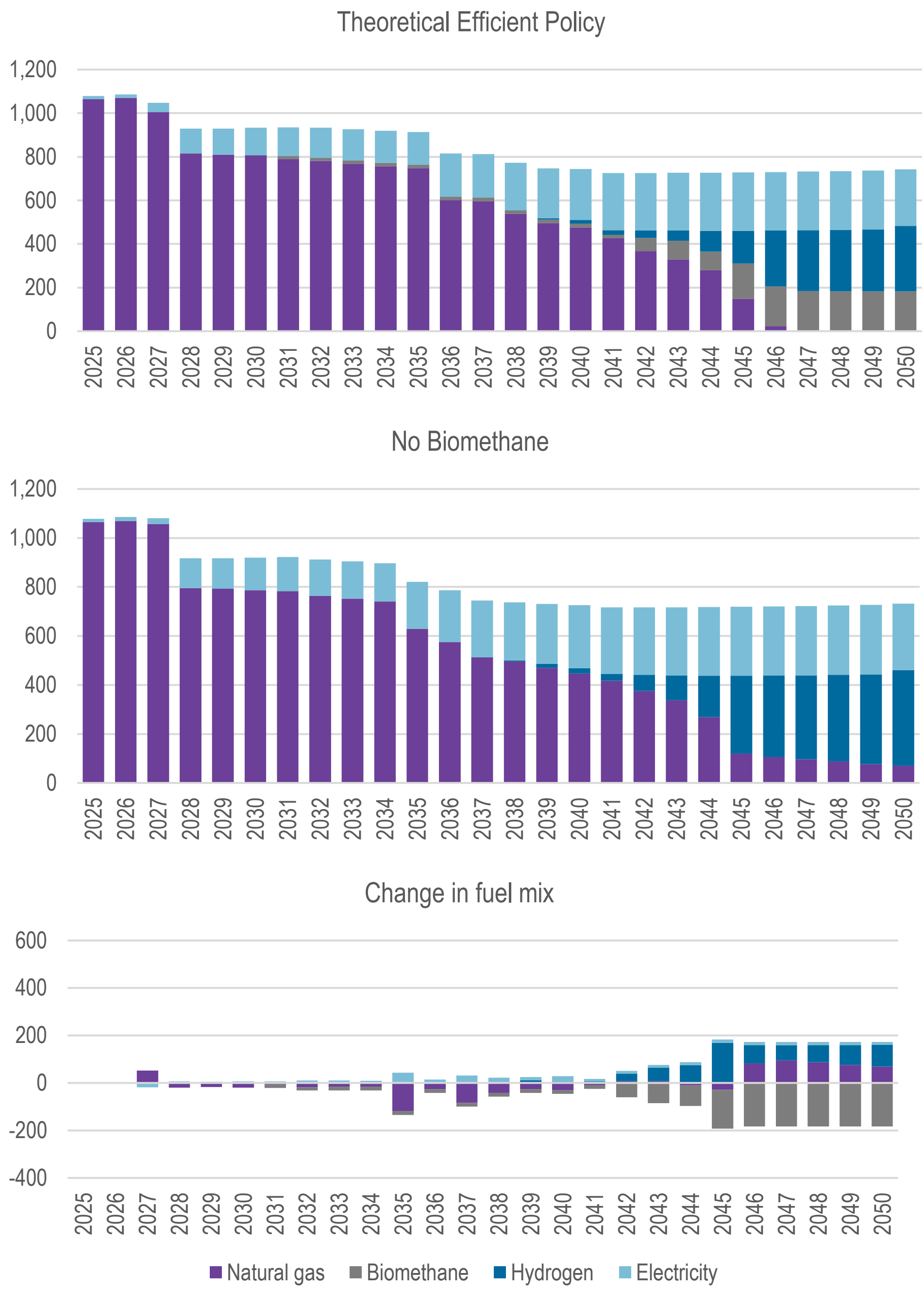
Source: Gas Transition Model

Figure E.4 Energy and appliance shares by sector and fuel type in 2050: Hydrogen Cost sensitivity



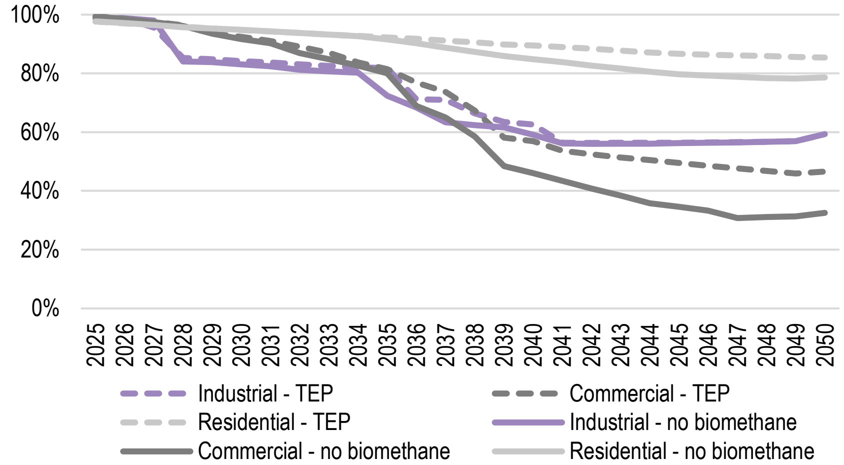
Source: Gas Transition Model

Figure E.5 Fuel mix (PJ): Theoretical Efficient Policy scenario, No Biomethane sensitivity, and change between Theoretical Efficient Policy scenario and No Biomethane sensitivity



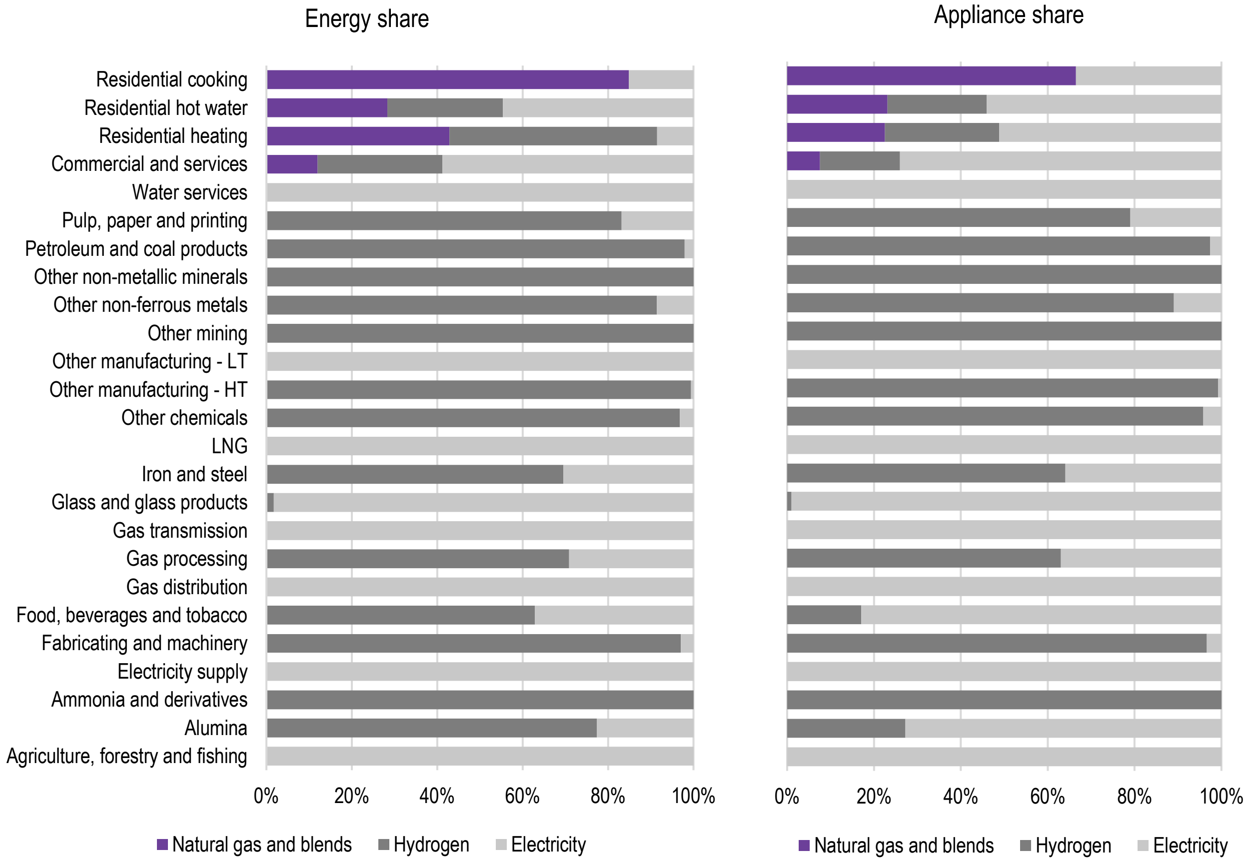
Source: Gas Transition Model

Figure E.6 Gaseous fuel share (%), by sector: No Biomethane sensitivity compared to Theoretical Efficient Policy scenario



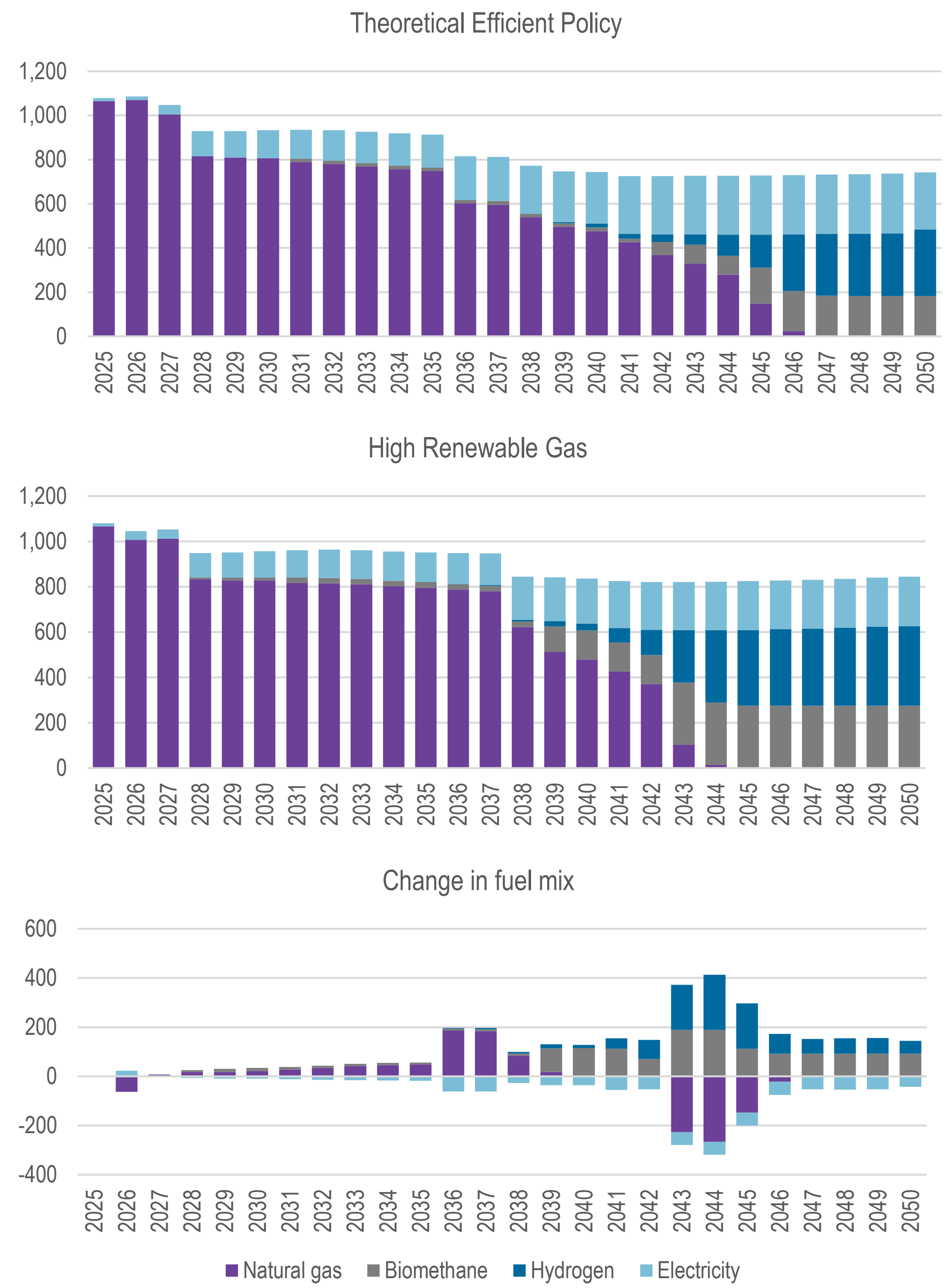
Source: Gas Transition Model

Figure E.7 Energy and appliance shares by sector and fuel type in 2050: No Biomethane sensitivity



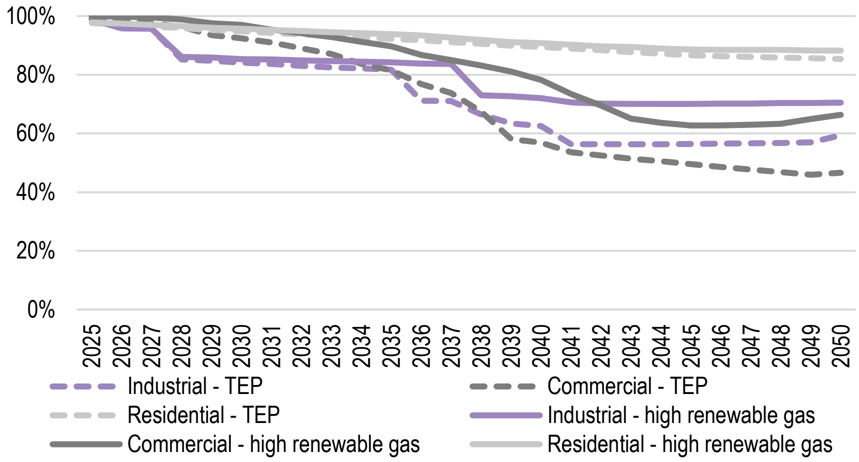
Source: Gas Transition Model

Figure E.8 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Renewable Gas sensitivity, and change between Theoretical Efficient Policy scenario and High Renewable Gas sensitivity



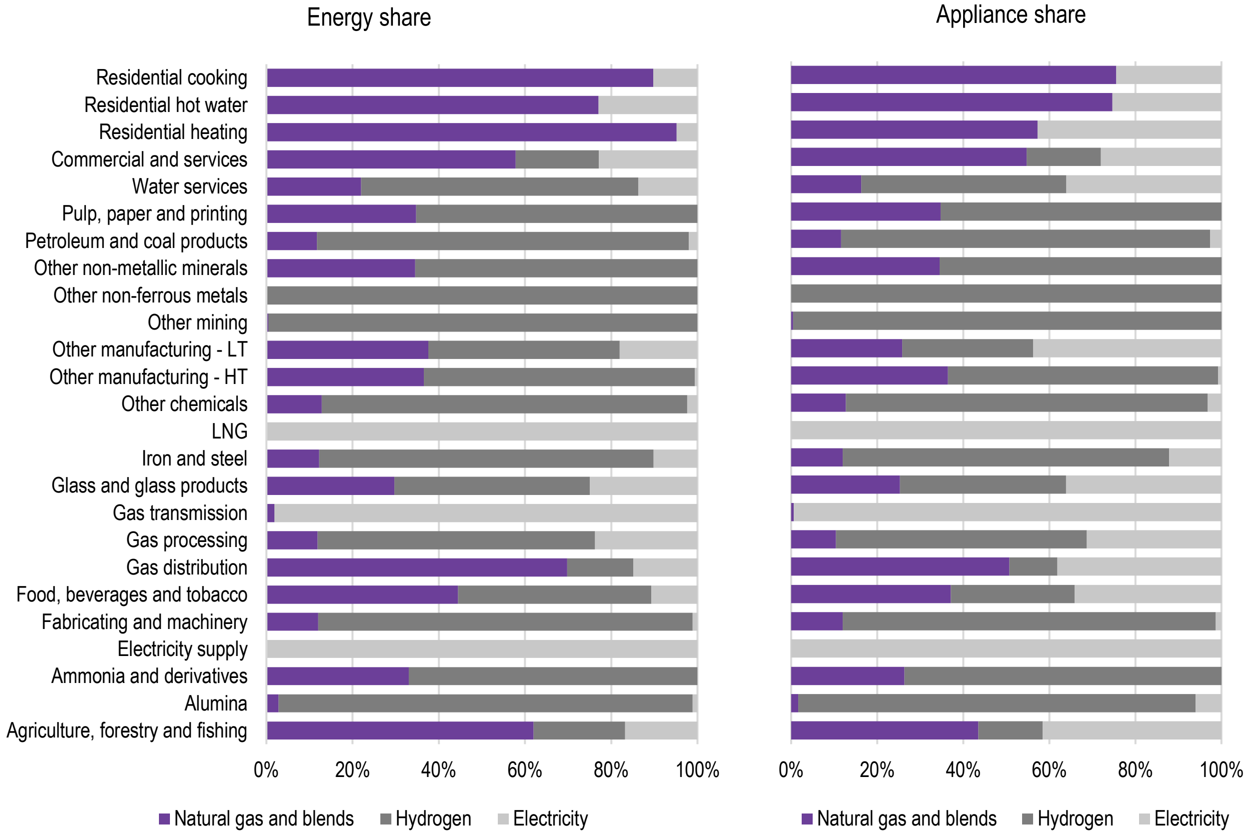
Source: Gas Transition Model

Figure E.9 Gaseous fuel share (%), by sector: High Renewable Gas sensitivity compared to Theoretical Efficient Policy scenario



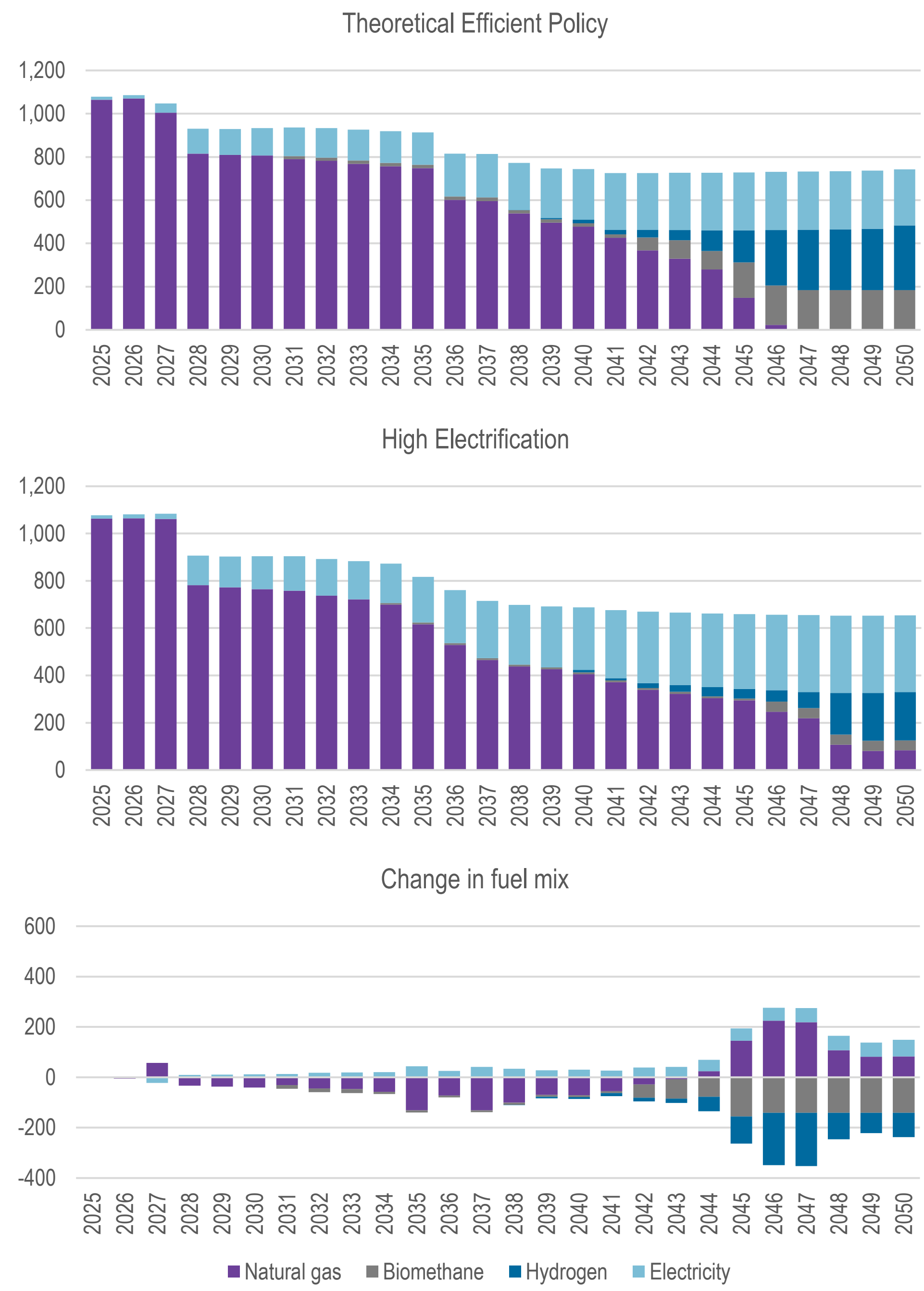
Source: Gas Transition Model

Figure E.10 Energy and appliance shares by sector and fuel type in 2050: High Renewable Gas sensitivity



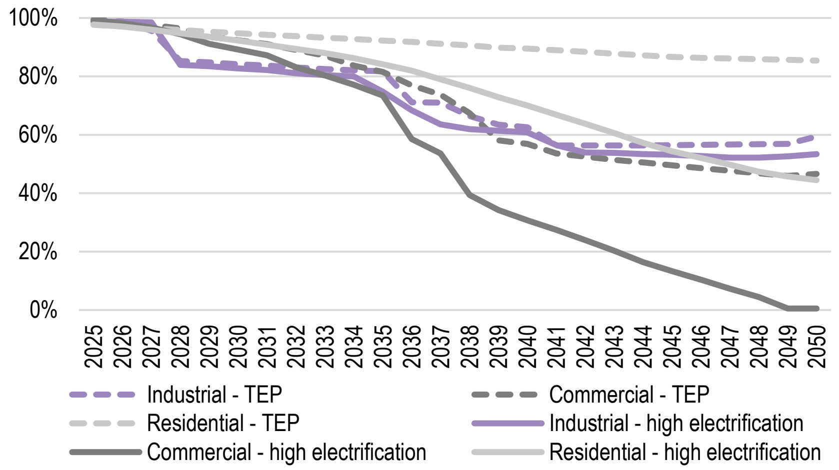
Source: Gas Transition Model

Figure E.11 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Electrification sensitivity, and change between Theoretical Efficient Policy scenario and High Electrification sensitivity



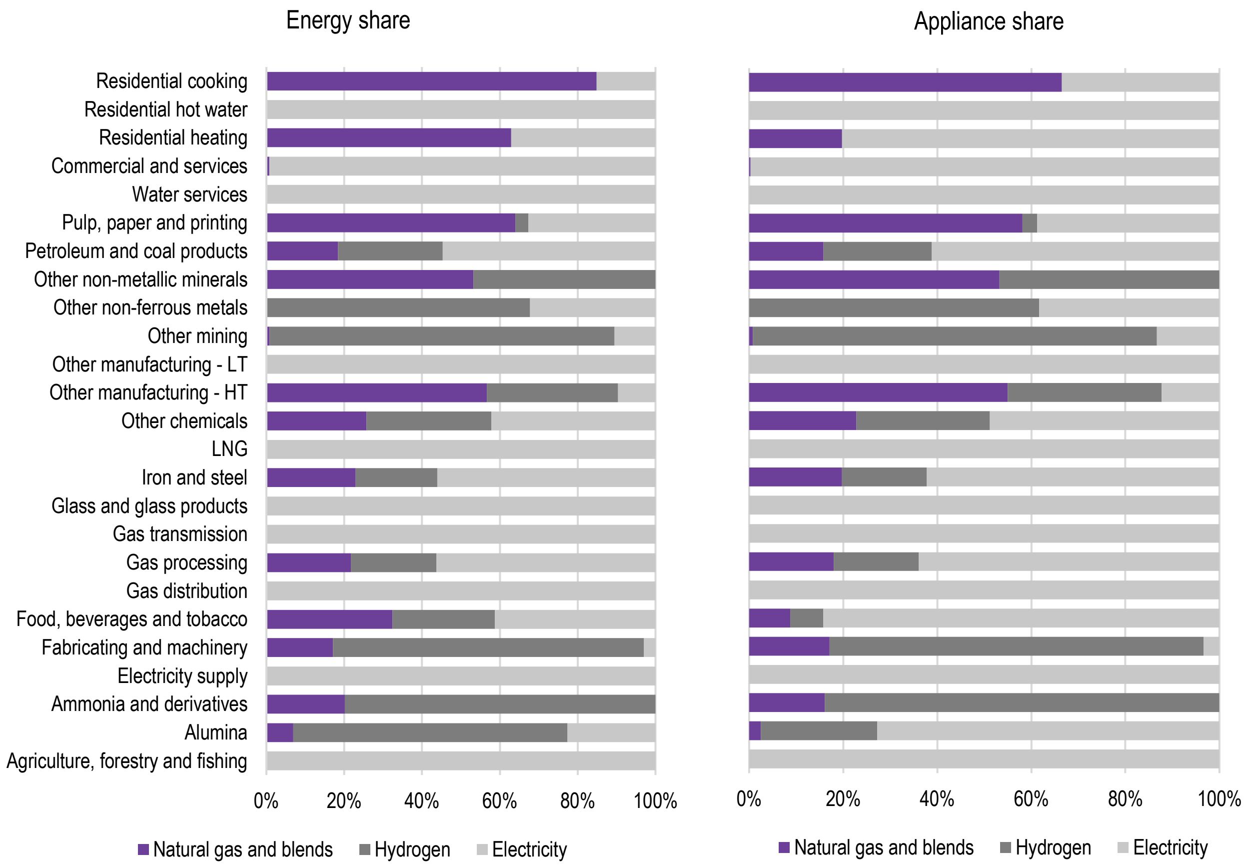
Source: Gas Transition Model

Figure E.12 Gaseous fuel share (%), by sector: High Electrification sensitivity compared to Theoretical Efficient Policy scenario



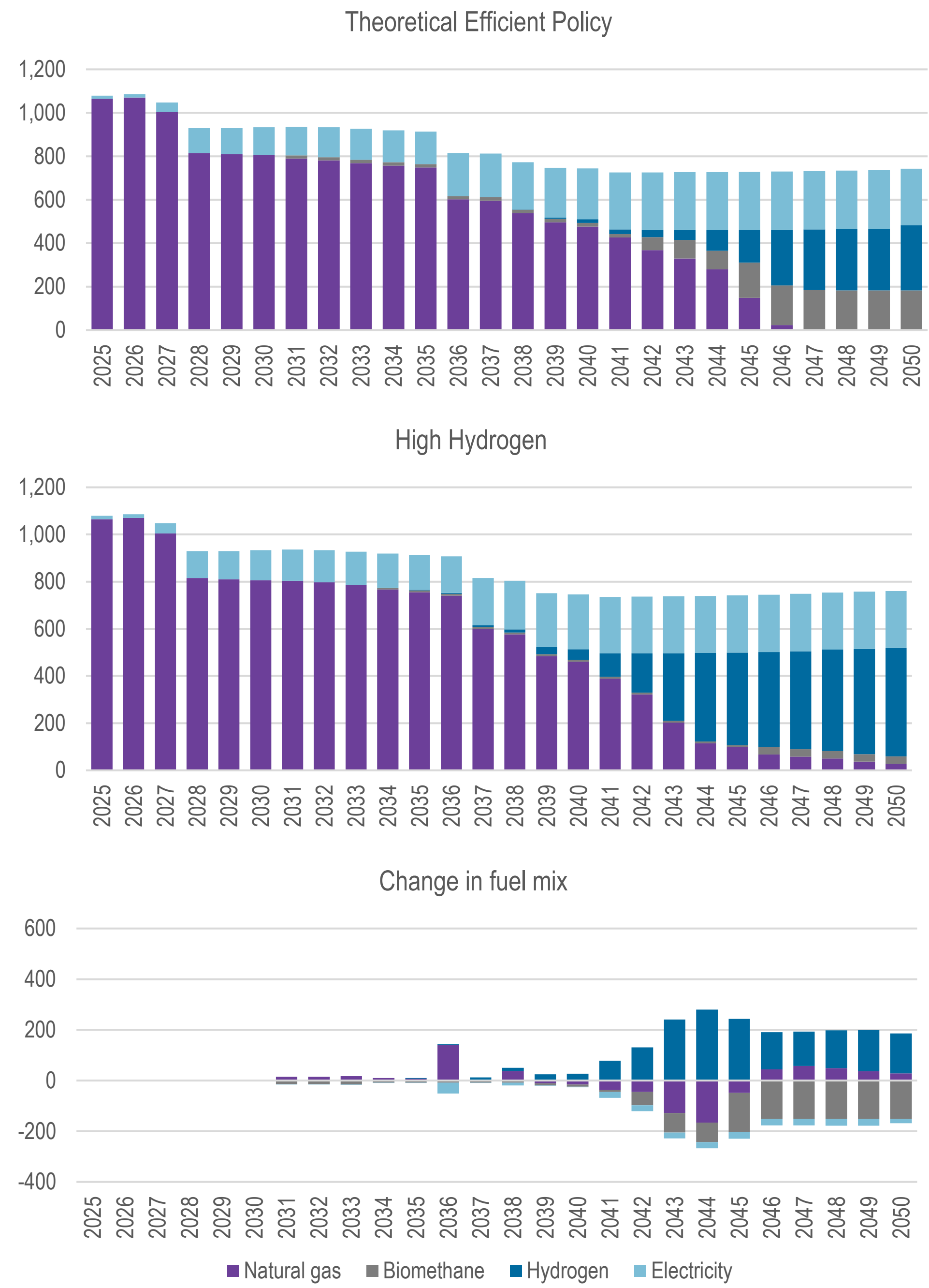
Source: Gas Transition Model

Figure E.13 Energy and appliance shares by sector and fuel type in 2050: High Electrification sensitivity



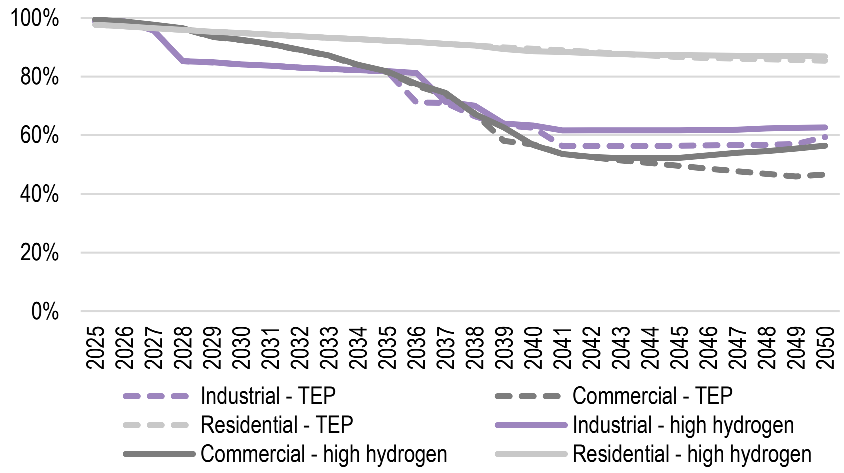
Source: Gas Transition Model

Figure E.14 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Hydrogen sensitivity, and change between Theoretical Efficient Policy scenario and High Hydrogen sensitivity



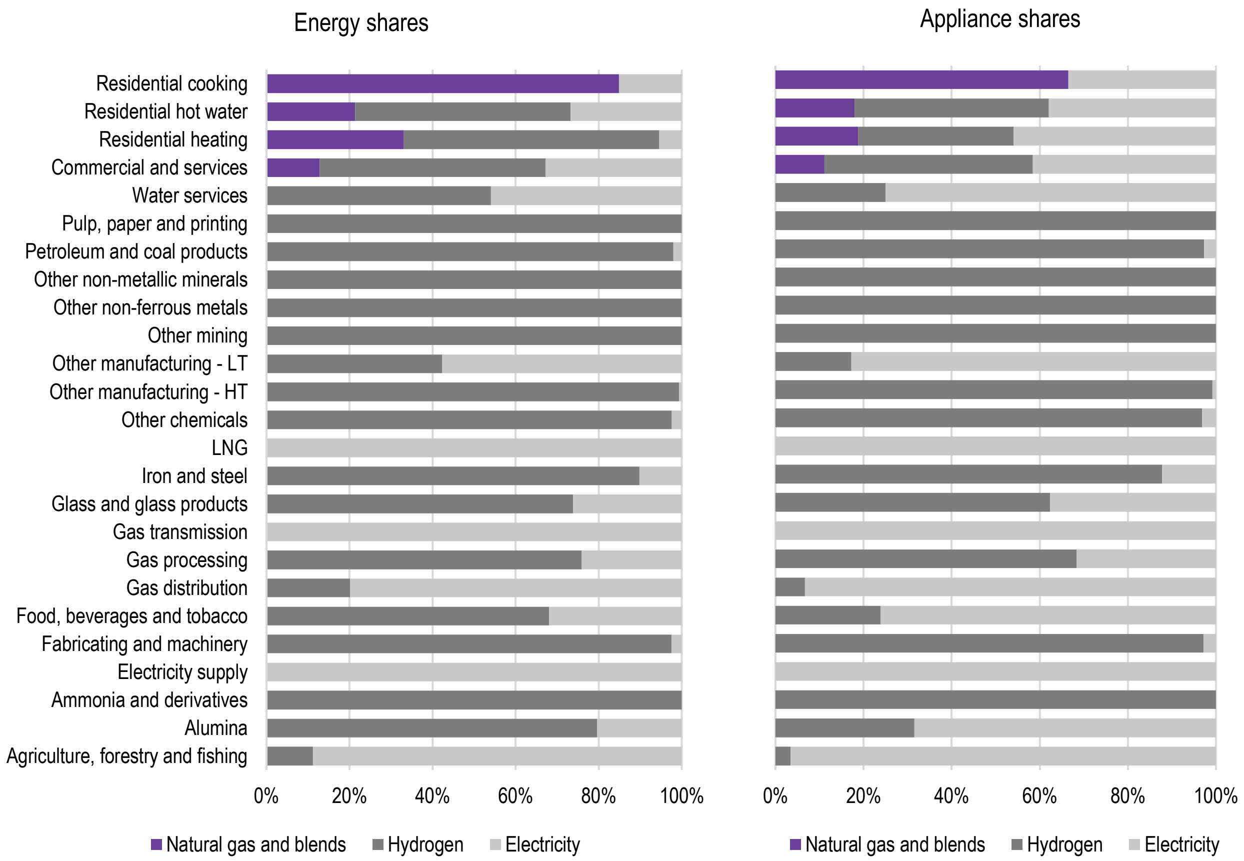
Source: Gas Transition Model

Figure E.15 Gaseous fuel share (%), by sector: High Hydrogen sensitivity compared to Theoretical Efficient Policy scenario



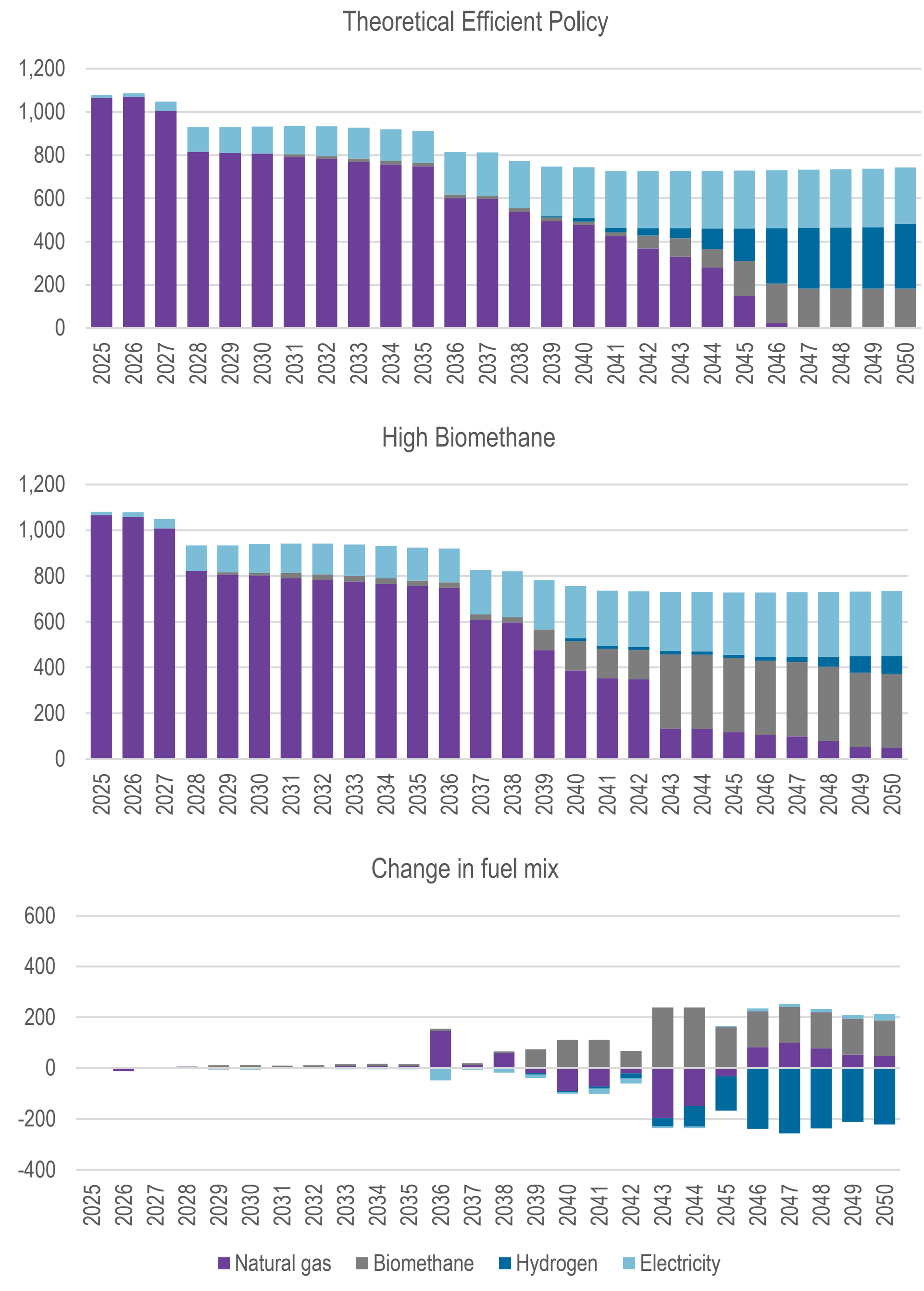
Source: Gas Transition Model

Figure E.16 Energy and appliance shares by sector and fuel type in 2050: High Hydrogen sensitivity



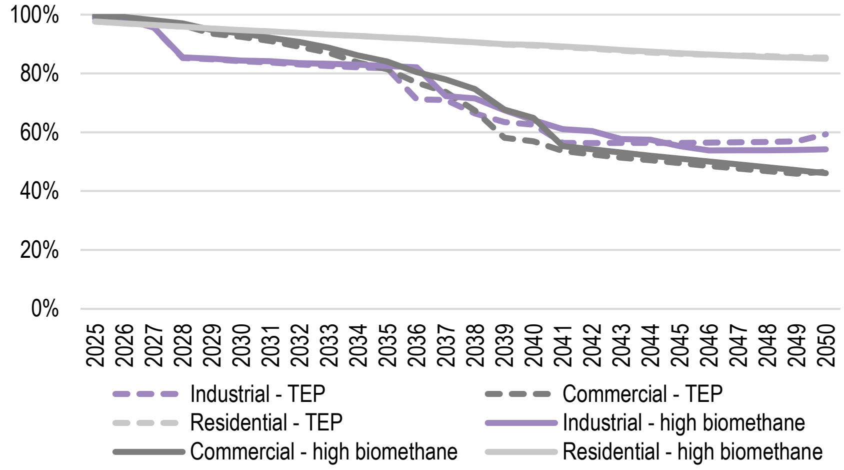
Source: Gas Transition Model

Figure E.17 Fuel mix (PJ): Theoretical Efficient Policy scenario, High Biomethane sensitivity, and change between Theoretical Efficient Policy scenario and High Biomethane sensitivity



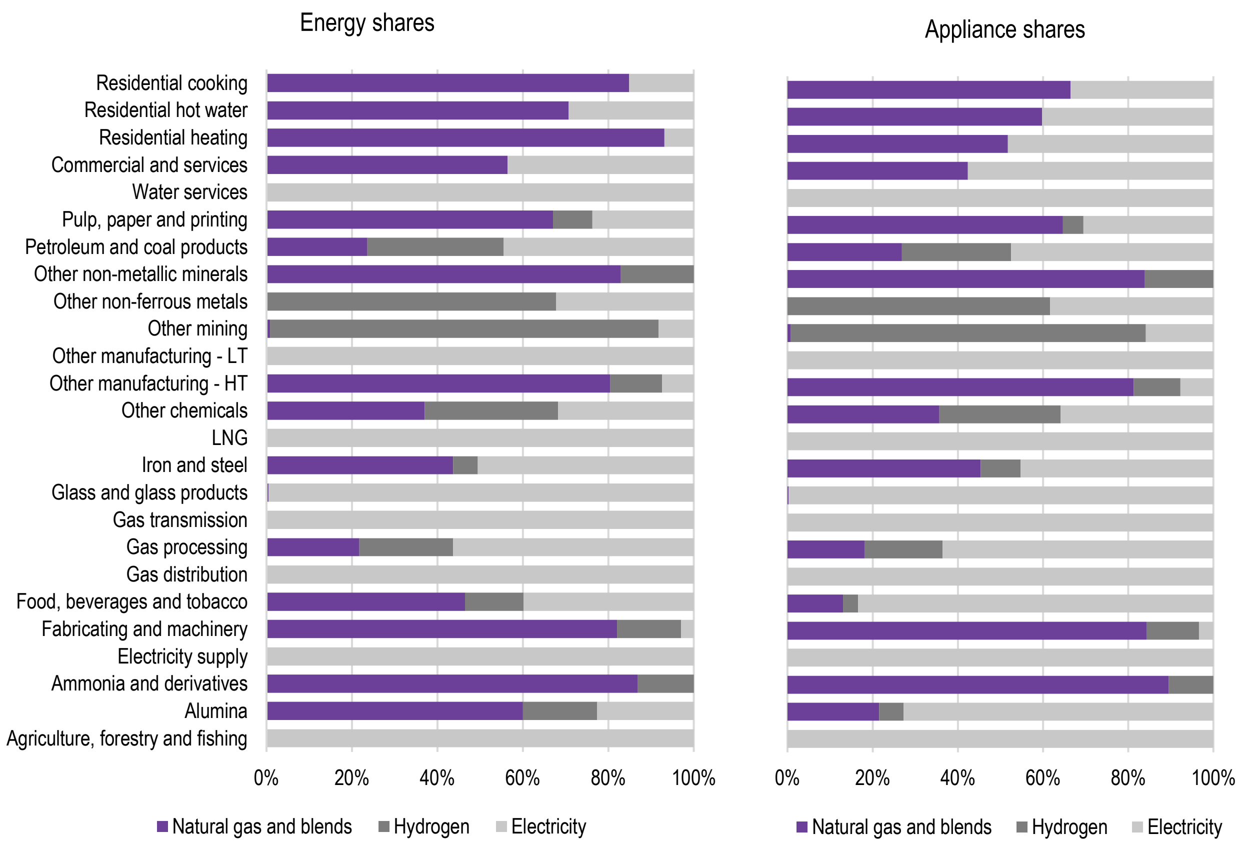
Source: Gas Transition Model

Figure E.18 Gaseous fuel share (%), by sector: High Biomethane sensitivity compared to Theoretical Efficient Policy scenario



Source: Gas Transition Model

Figure E.19 Energy and appliance shares by sector and fuel type in 2050: High Biomethane sensitivity



Source: Gas Transition Model

Overview of Tasman Global F

Tasman Global is a dynamic, global CGE model that has been developed by ACIL Allen for the purpose of undertaking economic impact analysis at the regional, state, national and global level.

A CGE model captures the interlinkages between the markets of all commodities and factors, taking into account resource constraints, to find a simultaneous equilibrium in all markets. A global CGE model extends this interdependence of the markets across world regions and finds simultaneous equilibrium globally. A dynamic model adds onto this the interconnection of equilibrium economies across time periods. For example, investments made today are going to determine the capital stocks of tomorrow and hence future equilibrium outcomes depend on today's equilibrium outcome, and so on.

A dynamic global CGE model, such as *Tasman Global*, has the capability of addressing total, sectoral, spatial and temporal efficiency of resource allocation as it connects markets globally and over time. Being a recursively dynamic model, however, its ability to address temporal issues is limited. In particular, *Tasman Global* cannot typically address issues requiring partial or perfect foresight. However, as documented in Jakeman et al (2001), it is possible to introduce partial or perfect foresight in certain markets using algorithmic approaches.[40] Notwithstanding this, the model does have the capability to project the economic impacts over time of given changes in policies, tastes and technologies in any region of the world economy on all sectors and agents of all regions of the world economy.

Tasman Global was developed from the 2001 version of the Global Trade and Environment Model (GTEM) developed by ABARE (Pant 2007)[41] and has been evolving ever since. In turn, GTEM was developed out of the MEGABARE model,[42] which contained significant advancements over the Global Trade Analysis Project (GTAP) model of that time.[43]

F.1 A dynamic model

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before an economic disturbance and one following). A dynamic model such as *Tasman Global* is beneficial

[40] Jakeman, G., Heyhoe, E., Pant, H., Woffenden, K. and Fisher, B.S. (2001). *The Kyoto Protocol: economic impacts under the terms of the Bonn agreement*. ABARE paper presented to the International Petroleum Industry Environmental Conservation Association conference, 'Long Term Carbon and Energy Management - Issues and Approaches', Cambridge, Massachusetts, 15-16 October.

[41] Pant, H.M. (2007), *GTEM: Global Trade and Environment Model*, ABARE Technical Report, Canberra, June.

[42] Hanslow, K. & Hinchy, M. (1996). *The MEGABARE model: interim documentation*. Canberra: ABARE.

[43] Hertel, T. (1997). *Global Trade Analysis: modelling and applications.* Cambridge University Press, Cambridge.

when analysing issues for which both the timing of and the adjustment path that economies follow are relevant in the analysis.

F.2 The database

A key advantage of *Tasman Global* is the level of detail in the database underpinning the model. The database is derived from the GTAP database.[44] This database is a fully documented, publicly available global data base which contains complete bilateral trade information, transport and protection linkages among regions for all GTAP commodities. It is the most detailed database of its type in the world.

Tasman Global builds on the GTAP database by adding the following important features:

— a detailed population and labour market database

— detailed technology representation within key industries (such as electricity generation and iron and steel production)

— disaggregation of a range of major commodities including iron ore, bauxite, alumina, primary aluminium, brown coal, black coal and LNG

— the ability to repatriate labour and capital income

— explicit representation of the states and territories of Australia

— the capacity to represent multiple regions within states and territories of Australia explicitly.

Nominally, version 10.1 of the *Tasman Global* database divides the world economy into 153 regions (145 international regions plus the 8 states and territories of Australia) although in reality the regions are frequently disaggregated further. ACIL Allen regularly models Australian or international projects or policies at the regional level including at the or at the state/territory/provincial level for various countries.

The *Tasman Global* database also contains a wealth of sectoral detail currently identifying up to 76 industries (Table F.1). The foundation of this information is the input-output tables that underpin the database. The input-output tables account for the distribution of industry production to satisfy industry and final demands.

Industry demands, so-called intermediate usage, are the demands from each industry for inputs. For example, electricity is an input into the production of communications. In other words, the communications industry uses electricity as an intermediate input.

Final demands are those made by households, governments, investors and foreigners (export demand). These final demands, as the name suggests, represent the demand for finished goods and services. To continue the example, electricity is used by households – their consumption of electricity is a final demand.

Each sector in the economy is typically assumed to produce one commodity, although in *Tasman Global*, the electricity, transport and iron and steel sectors are modelled using a 'technology bundle' approach. With this approach, different known production methods are used to generate a homogeneous output for the 'technology bundle' industry. For example, electricity can be generated using brown coal, black coal, petroleum, base load gas, peak load gas, nuclear, hydro, geothermal, biomass, wind, solar or other renewable based technologies – each of which has its own cost structure.

[44] Aguiar, A., Chepeliev, M., Corong, E., McDougall, R., & van der Mensbrugghe, D. (2019). The GTAP Data Base: Version 10. *Journal of Global Economic Analysis*, 4(1), 1-27. Retrieved from https://www.jgea.org/ojs/index.php/jgea/article/view/77.

The other key feature of the database is that the cost structure of each industry is also represented in detail. Each industry purchases intermediate inputs (from domestic and imported sources) primary factors (labour, capital, land and natural resources) as well as paying taxes or receiving subsidies.

Table F.1 Standard sectors in the Tasman Global CGE model

no	Name	no	Name
1	Paddy rice	39	Diesel (incl. nonconventional diesel)
2	Wheat	40	Other petroleum, coal products
3	Cereal grains nec	41	Hydrogen
4	Vegetables, fruit, nuts	42	Chemical, rubber, plastic products
5	Oil seeds	43	Iron ore
6	Sugar cane, sugar beet	44	Bauxite
7	Plant- based fibres	45	Mineral products nec
8	Crops nec	46	Ferrous metals
9	Bovine cattle, sheep, goats, horses	47	Alumina
10	Pigs	48	Primary aluminium
11	Animal products nec	49	Metals nec
12	Raw milk	50	Metal products
13	Wool, silk worm cocoons	51	Motor vehicle and parts
14	Forestry	52	Transport equipment nec
15	Fishing	53	Electronic equipment
16	Brown coal	54	Machinery and equipment nec
17	Black coal	55	Manufactures nec
18	Oil	56	Electricity generation
19	LNG	57	Electricity transmission and distribution
20	Other natural gas	58	Gas manufacture, distribution
21	Minerals nec	59	Water
22	Bovine meat products	60	Construction
23	Pig meat products	61	Trade
24	Meat products nec	62	Road transport
25	Vegetables oils and fats	63	Rail and pipeline transport
26	Dairy products	64	Water transport
27	Processed rice	65	Air transport
28	Sugar	66	Transport nec
29	Food products nec	67	Warehousing and support activities
30	Wine	68	Communication
31	Beer	69	Financial services nec
32	Spirits and RTDs	70	Insurance
33	Other beverages and tobacco products	71	Business services nec
34	Textiles	72	Recreational and other services
35	Wearing apparel	73	Public Administration and Defence
36	Leather products	74	Education
37	Wood products	75	Human health and social work activities
38	Paper products, publishing	76	Dwellings

Note: nec = not elsewhere classified.

Source: ACIL Allen

F.3 Model structure

Given its heritage, the structure of the *Tasman Global* model closely follows that of the GTAP and GTEM models and interested readers are encouraged to refer to the documentation of these models for more detail.[45] In summary:

- The model divides the world into a variety of regions and international waters.
  - Each region is fully represented with its own 'bottom-up' social accounting matrix and could be a local community, an LGA, state, country or a group of countries. The number of regions in a given simulation depends on the database aggregation. Each region consists of households, a government with a tax system, production sectors, investors, traders and finance brokers.
  - 'International waters' are a hypothetical region in which global traders operate and use international shipping services to ship goods from one region to the other. It also houses an international finance 'clearing house' that pools global savings and allocates the fund to investors located in every region.
  - Each region has a 'regional household'[46] that collects all factor payments, taxes, net foreign borrowings, net repatriation of factor incomes due to foreign ownership and any net income from trading of emission permits.
- The income of the regional household is allocated across private consumption, government consumption and savings according to a Cobb-Douglas utility function, which, in practice, means that the share of income going to each component is assumed to remain constant in nominal terms.
- Private consumption of each commodity is determined by maximising utility subject to a Constant Difference of Elasticities (CDE) function which includes both price and income elasticities.
- Government consumption of each commodity is determined by maximising utility subject to a Cobb-Douglas utility function.
- Each region has *n* production sectors, each producing single products using various production functions where they aim to maximise profits (or minimise costs) and take all prices as given. The nature of the production functions chosen in the model means that producers exhibit constant returns to scale.
  - In general, each producer supplies consumption goods by combining an aggregate energy-primary factor bundle with other intermediate inputs and according to a Leontief production function (which in practice means that the quantity shares remain in fixed proportions). Within the aggregate energy-primary factor bundle, the individual energy commodities and primary factors are combined using a nested Constant Elasticity of Substitution (CES) production function, in which energy and primary factor aggregates substitute according to a CES function with the individual energy commodities and individual primary factors substituting with their respective aggregates according to further CES production functions.
  - Exceptions to the above include the electricity generation, iron and steel and road transport sectors. These sectors employ the 'technology bundle' approach developed by ABARE[47] in which non-homogenous technologies are employed to produce a homogenous output with the choice of technology governed by minimising costs according to a modified Constant Ratios of Elasticities of Substitution, Homothetic (CRESH) production function. For example, electricity may be generated from a variety of

[45] Namely Hertel, T. (1997). Op. cit. and Pant, H.M. (2007). Op. cit., respectively.

[46] The term "regional household" was devised for the GTAP model. In essence it is an agent that aggregates all incomes attributable to the residents of a given region before distributing the funds to the various types of regional consumption (including savings).

[47] Hanslow, K. & Hinchy, M. (1996). Op. cit.

technologies (including brown coal, black coal, gas, nuclear, hydro, solar etc.), iron and steel may be produced from blast furnace or electric arc technologies while road transport services may be supplied using a range of different vehicle technologies. The 'modified-CRESH' function differs from the traditional CRESH function by also imposing the condition that the quantity units are homogenous.

— There are four primary factors (land, labour, mobile capital and fixed capital). While labour and mobile capital are used by all production sectors, land is only used by agricultural sectors while fixed capital is typically employed in industries with natural resources (such as fishing, forestry and mining) or in selected industries built by ACIL Allen.
  — Land supply in each region is typically assumed to remain fixed through time with the allocation of land between sectors occurring to maximise returns subject to a Constant Elasticity of Transformation (CET) utility function.
  — Mobile capital accumulates as a result of net investment. It is implicitly assumed in *Tasman Global* that it takes one year for capital to be installed. Hence, supply of capital in the current period depends on the last year's capital stock and investments made during the previous year.
  — Labour supply in each year is determined by endogenous changes in population, given participation rates and a given unemployment rate. In policy scenarios, the supply of labour is positively influenced by movements in the real wage rate governed by the elasticity of supply. For countries where sub-regions have been specified (such as Australia), migration between regions is induced by changes in relative real wages with the constraint that net interregional migration equals zero. For regions where the labour market has been disaggregated to include occupations, there is limited substitution allowed between occupations by individuals supplying labour (according to a CET utility function) and by firms demanding labour (according to a CES production function) based on movements in relative real wages.
  — The supply of fixed capital is given for each sector in each region.

  The model has the option for these assumptions to be changed at the time of model application if alternative factor supply behaviours are considered more relevant.

— It is assumed that labour (by occupation) and mobile capital are fully mobile across production sectors implying that, in equilibrium, wage rates (by occupation) and rental rates on capital are equalised across all sectors within each region. To a lesser extent, labour and capital are mobile between regions through international financial investment and migration, but this sort of mobility is sluggish and does not equalise rates of return across regions.

— For most international regions, for each consumer (private, government, industries and the local investment sector), consumption goods can be sourced either from domestic or imported sources. In any country that has disaggregated regions (such as Australia), consumption goods can also be sourced from other intrastate or interstate regions. In all cases, the source of non-domestically produced consumption goods is determined by minimising costs subject to a CRESH utility function. Like most other CGE models, a CES demand function is used to model the relative demand for domestically produced commodities versus non-domestically produced commodities. The elasticities chosen for the CES and CRESH demand functions mean that consumers in each region have a higher preference for domestically produced commodities than non-domestic commodities and a higher preference for intrastate- or interstate-produced commodities than foreign commodities.

— The capital account in *Tasman Global* is open. Domestic savers in each region purchase 'bonds' in the global financial market through local 'brokers' while investors in each region sell bonds to the global financial market to raise investible funds. A flexible global interest rate clears the global financial market.

— It is assumed that regions may differ in their risk characteristics and policy configurations. As a result, rates of return on money invested in physical capital may differ between regions and therefore may be different from the global cost of funds. Any difference between the local rates of return on capital and the global cost of borrowing is treated as the result of the existence of a risk premium and policy imperfections in the international capital market. It is maintained that the equilibrium allocation of investment requires the equalisation of changes in (as opposed to the absolute levels of) rates of return over the base year rates of return.

— Any excess of investment over domestic savings in a given region causes an increase in the net debt of that region. It is assumed that debtors service the debt at the interest rate that clears the global financial market. Similarly, regions that are net savers gives rise to interest receipts from the global financial market at the same interest rate.

— Investment in each region is used by the regional investor to purchase a suite of intermediate goods according to a Leontief production function to construct capital stock with the regional investor cost minimising by choosing between domestic, interstate and imported sources of each intermediate good via the CRESH production function. The regional cost of creating new capital stock versus the local rates of return on mobile capital is what determines the regional rate of return on new investment.

— In equilibrium, exports of a good from one region to the rest of world are equal to the import demand for that good in the remaining regions. Together with the merchandise trade balance, the net payments on foreign debt add up to the current account balance. *Tasman Global* does not require that the current account be in balance every year. It allows the capital account to move in a compensatory direction to maintain the balance of payments. The exchange rate provides the flexibility to keep the balance of payments in balance.

— Detailed bilateral transport margins for every commodity are specified in the starting database. By default, the bilateral transport mode shares are assumed to be constant, with the supply of international transportation services by each region solved by a cost-minimising international trader according to a Cobb-Douglas demand function.

— Emissions of six anthropogenic greenhouse gases (namely, carbon dioxide, methane, nitrous oxide, HFCs, PFCs and SF_6) associated with economic activity are tracked in the model. Almost all sources and sectors are represented; emissions from agricultural residues and land-use change and forestry activities are not explicitly modelled but can be accounted for externally. Prices can be applied to emissions which are converted to industry-specific production taxes or commodity-specific sales taxes that impact on demand. Abatement technologies similar to those adopted in a report released by the Commonwealth Government (2008) are available and emission quotas can be set globally or by region along with allocation schemes that enable emissions to be traded between regions.[48]

More detail regarding specific elements of the model structure is discussed in the following sections.

F.4 Population growth and labour supply

Population growth is an important determinant of economic growth through the supply of labour and the demand for final goods and services. Population growth for each region represented in the *Tasman Global* database is projected using ACIL Allen's in-house demographic model. The demographic model projects how the population in each region grows and how age and gender composition changes over time and is an important tool for determining the changes in regional labour supply and total population over the projected period.

For each of region, the model projects the changes in age-specific birth, mortality and net migration rates by gender for 101 age cohorts (0-99 and 100+). The demographic model also projects

[48] Australian Government (2008), *Australia's Low Pollution Future: the economics of climate change mitigation*, Australian Government, Canberra.

changes in participation rates by gender by age for each region, and, when combined with the age and gender composition of the population, endogenously projects the future supply of labour in each region. Changes in life expectancy are a function of income per person as well as assumed technical progress on lowering mortality rates for a given income (for example, reducing malaria-related mortality through better medicines, education, governance etc.). Participation rates are a function of life expectancy as well as expected changes in higher education rates, fertility rates and changes in the work force as a share of the total population.

Labour supply is derived from the combination of the projected regional population by age by gender and regional participation rates by age by gender. Over the projected period labour supply in most developed economies is projected to grow slower than total population because of ageing population effects.

For the Australian states and territories, the projected aggregate labour supply from ACIL Allen's demographic module is used as the base level potential workforce for the detailed Australian labour market module, which is described in the next section.

F.5 The Australian labour market

Tasman Global has a detailed representation of the Australian labour market which has been designed to capture:

— different occupations

— changes to participation rates (or average hours worked) due to changes in real wages

— changes to unemployment rates due to changes in labour demand

— limited substitution between occupations by the firms demanding labour and by the individuals supplying labour, and

— limited labour mobility between states and regions within each state.

Tasman Global recognises 97 different occupations within Australia – although the exact number of occupations depends on the aggregation. The firms that hire labour are provided with some limited scope to change between these 97 labour types as the relative real wage between them changes. Similarly, the individuals supplying labour have a limited ability to change occupations in response to the changing relative real wage between occupations. Finally, as the real wage for a given occupation rises in one state relative to other states, workers are given some ability to respond by shifting their location. The model produces results at the 97 3-digit Australian New Zealand Standard Classification of Occupations (ANZSCO) level which are presented in Table F.2.

The labour market structure of *Tasman Global* is thus designed to capture the reality of labour markets in Australia, where supply and demand at the occupational level do adjust, but within limits.

Labour supply in *Tasman Global* is presented as a three-stage process:

1. labour makes itself available to the workforce based on movements in the real wage and the unemployment rate
2. labour chooses between occupations in a state based on relative real wages within the state
3. labour of a given occupation chooses in which state to locate based on movements in the relative real wage for that occupation between states.

By default, *Tasman Global*, like all CGE models, assumes that markets clear. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model).

Table F.2 Occupations in the Tasman Global database, ANZSCO 3-digit level (minor groups)

ANZSCO code, Description	ANZSCO code, Description	ANZSCO code, Description
1. MANAGERS	**3. TECHNICIANS & TRADES WORKERS**	**5. CLERICAL & ADMINISTRATIVE**
111 Chief Executives, General Managers and Legislators	311 Agricultural, Medical and Science Technicians	511 Contract, Program and Project Administrators
121 Farmers and Farm Managers	312 Building and Engineering Technicians	512 Office and Practice Managers
131 Advertising and Sales Managers	313 ICT and Telecommunications Technicians	521 Personal Assistants and Secretaries
132 Business Administration Managers	321 Automotive Electricians and Mechanics	531 General Clerks
133 Construction, Distribution and Production Managers	322 Fabrication Engineering Trades Workers	532 Keyboard Operators
134 Education, Health and Welfare Services Managers	323 Mechanical Engineering Trades Workers	541 Call or Contact Centre Information Clerks
135 ICT Managers	324 Panel beaters, and Vehicle Body Builders, Trimmers and Painters	542 Receptionists
139 Miscellaneous Specialist Managers	331 Bricklayers, and Carpenters and Joiners	551 Accounting Clerks and Bookkeepers
141 Accommodation and Hospitality Managers	332 Floor Finishers and Painting Trades Workers	552 Financial and Insurance Clerks
142 Retail Managers	333 Glaziers, Plasterers and Tilers	561 Clerical and Office Support Workers
149 Miscellaneous Hospitality, Retail and Service Managers	334 Plumbers	591 Logistics Clerks
	341 Electricians	599 Miscellaneous Clerical and Administrative Workers
2. PROFESSIONALS	342 Electronics and Telecommunications Trades Workers	
211 Arts Professionals	351 Food Trades Workers	**6. SALES WORKERS**
212 Media Professionals	361 Animal Attendants and Trainers, and Shearers	611 Insurance Agents and Sales Representatives
221 Accountants, Auditors and Company Secretaries	362 Horticultural Trades Workers	612 Real Estate Sales Agents
222 Financial Brokers and Dealers, and Investment Advisers	391 Hairdressers	621 Sales Assistants and Salespersons
223 Human Resource and Training Professionals	392 Printing Trades Workers	631 Checkout Operators and Office Cashiers
224 Information and Organisation Professionals	393 Textile, Clothing and Footwear Trades Workers	639 Miscellaneous Sales Support Workers
225 Sales, Marketing and Public Relations Professionals	394 Wood Trades Workers	
231 Air and Marine Transport Professionals	399 Miscellaneous Technicians and Trades Workers	**7. MACHINERY OPERATORS & DRIVERS**
232 Architects, Designers, Planners and Surveyors		711 Machine Operators
233 Engineering Professionals	**4. COMMUNITY & PERSONAL SERVICE**	712 Stationary Plant Operators
234 Natural and Physical Science Professionals	411 Health and Welfare Support Workers	721 Mobile Plant Operators
241 School Teachers	421 Child Carers	731 Automobile, Bus and Rail Drivers
242 Tertiary Education Teachers	422 Education Aides	732 Delivery Drivers
249 Miscellaneous Education Professionals	423 Personal Carers and Assistants	733 Truck Drivers
251 Health Diagnostic and Promotion Professionals	431 Hospitality Workers	741 Store persons
252 Health Therapy Professionals	441 Defence Force Members, Fire Fighters and Police	
253 Medical Practitioners	442 Prison and Security Officers	**8. LABOURERS**
254 Midwifery and Nursing Professionals	451 Personal Service and Travel Workers	811 Cleaners and Laundry Workers
261 Business and Systems Analysts, and Programmers	452 Sports and Fitness Workers	821 Construction and Mining Labourers
262 Database and Systems Administrators, and ICT Security Specialists		831 Food Process Workers
263 ICT Network and Support Professionals		832 Packers and Product Assemblers
271 Legal Professionals		839 Miscellaneous Factory Process Workers
272 Social and Welfare Professionals		841 Farm, Forestry and Garden Workers
		851 Food Preparation Assistants
		891 Freight Handlers and Shelf Fillers
		899 Miscellaneous Labourers

Source: ABS (2009), ANZSCO – Australian and New Zealand Standard Classifications Of Occupations, First edition, Revision 1, ABS catalogue no. 1220.0.

The *Tasman Global* database includes a detailed representation of the Australian labour market that has been designed to capture the supply and demand for different skills and occupations by industry. To achieve this, the Australian workforce is characterised by detailed supply and demand matrices.

On the supply side, the Australian population is characterised by a five-dimensional matrix consisting of:

— 7 post-school qualification levels
— 12 main qualification fields of highest educational attainment
— 97 occupations
— 101 age groups (namely 0 to 99 and 100+)
— 2 genders.

The data for this matrix is measured in persons and was sourced from the ABS 2011 Census. As the skills elements of the database and model structure have not been used for this project, it will be ignored in this discussion.

The 97 occupations are those specified at the 3-digit level (or Minor Groups) under the ANZSCO (see Table F.2).

On the demand side, each industry demands a particular mix of occupations. This matrix is specified in units of FTE jobs where an FTE employee works an average of 37.5 hours per week. Consistent with the labour supply matrix, the data for FTE jobs by occupation by industry was also sourced from the ABS 2011 Census and updated using the latest labour force statistics.

Matching the demand and supply side matrices means that there is the implicit assumption that the average hours per worker are constant, but it is noted that mathematically changes in participation rates have the same effect as changes in average hours worked.

F.6 Labour market model structure

In the model, the underlying growth of each industry in the Australian economy results in a growth in demand for a particular set of skills and occupations. In contrast, the supply of each set of skills and occupations in a given year is primarily driven by the underlying demographics of the resident population. This creates a market for each skill by occupation that (unless specified otherwise) needs to clear at the start and end of each time period.[49] The labour markets clear by a combination of different prices (i.e. wages) for each labour type and by allowing a range of demand and supply substitution possibilities, including:

— changes in firms' demand for labour driven by changes in the underlying production technology
  – for technology bundle industries (electricity, iron and steel and road transportation) this occurs due to changes between explicitly identified alternative technologies
  – for non-technology bundle industries this includes substitution between factors (such as labour for capital) or energy for factors
— changes to participation rates (or average hours worked) due to changes in real wages
— changes in the occupations of a person due to changes in relative real wages
— substitution between occupations by the firms demanding labour due to changes in the relative costs
— changes to unemployment rates due to changes in labour demand, and
— limited labour mobility between states due to changes in relative real wages.

All of the labour supply substitution functions are modified-CET functions in which people supply their skills, occupation and rates of participation as a positive function of relative wages. However,

[49] For example, at the start and end of each week for this analysis. *Tasman Global* can be run with different steps in time, such as quarterly or bi-annually in which case the markets would clear at the start and end of these time points.

unlike a standard CET (or CES) function, the functions are 'modified' to enforce an additional constraint that the number of people is maintained before and after substitution.[50]

Although technically solved simultaneously, the labour market in *Tasman Global* can be thought of as a 5-stage process:

— labour makes itself available to the workforce based on movements in the real wage (that is, it actively participates with a certain number of average hours worked per week)
— the age, gender and occupations of the underlying population combined with the participation rate by gender by age implies a given supply of labour (the potentially available workforce)
— a portion of the potentially available workforce is unemployed, implying a given available labour force
— labour chooses to move between occupations based on relative real wages
— industries alter their demands for labour as a whole and for specific occupations based on the relative cost of labour to other inputs and the relative cost of each occupation.

By default, *Tasman Global*, like all CGE models, assumes that markets clear at the start and end of each period. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model). In principle, (subject to zero starting values) people of any age and gender can move between any of the 97 occupations while industries can produce their output with any mix of occupations. However, in practice the combination of the initial database, the functional forms, low elasticities and moderate changes in relative prices for skills, occupations etc. means that there is only low to moderate change induced by these functions. The changes are sufficient to clear the markets, but not enough to radically change the structure of the workforce in the timeframe of this analysis.

Factor-factor substitution elasticities in non-technology bundle industries are industry specific and are the same as those specified in the GTAP database[51], while the fuel-factor and technology bundle elasticities are the same as those specified in GTEM.[52] The detailed labour market elasticities are ACIL Allen assumptions, previously calibrated in the context of the model framework to replicate the historical change in the observed Australian labour market over a five year period[53]. The unemployment rate function in the policy scenarios is a non-linear function of the change in the labour demand relative to the base case with the elasticity being a function of the unemployment rate (that is, the lower the unemployment rate the lower the elasticity and the higher the unemployment rate the higher the elasticity).

50 As discussed in Dixon et al (1997), a standard CES/CET function is defined in terms of *effective units*. Quantitatively this means that, when substituting between, say, X_1 and X_2 to form a total quantity X using a CET function a simple summation generally does not actually equal X. Use of these functions is common practice in CGE models when substituting between substantially different units (such as labour versus capital or imported versus domestic services) but was not deemed appropriate when tracking the physical number of people. Such 'modified' functions have long been employed in the technology bundles of *Tasman Global* and GTEM. The Productivity Commission have proposed alternatives to the standard CES to overcome similar and other weaknesses when applied to internationally traded commodities. See Dixon, P.B., Parmenter, B., Sutton, J., & Vincent, D. (1997), *ORANI: A Multisectoral Model of the Australian Economy*, Amsterdam: North Holland.

51 Narayanan et al. (2012).

52 Pant, H.M. (2007), GTEM: *Global Trade and Environment Model*, ABARE Technical Report, Canberra, June.

53 This method is a common way of calibrating the economic relationships assumed in CGE models to those observed in the economy. See for example Dixon, P.B. and Rimmer, M.T. (2002), *Dynamic General Equilibrium Modelling for Forecasting and Policy*. Contributions to Economic Analysis 256, Amsterdam: North Holland.

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APGA Submission

Electricity and Energy Sector Plan Consultation

26 April 2024

Contents

List of Figures

List of Tables

Executive Summary

The Electricity and Energy Sector Plan (EESP) Discussion Paper is clear in its framing – Australia needs alternative low carbon fuels to achieve its emission reduction goals. Alternative low carbon fuels such as renewable gases and renewable liquid fuels are a critical part of the renewable energy ecosystem. Policy support for these new forms of renewable energy has been insufficient across the past decade and this must be addressed as a matter of urgency if Australia is to meet its climate ambition.

The Australian Pipelines and Gas Association (APGA) supports the intent of the EESP to explore policy support for alternative low carbon fuels. Decarbonising existing fuel supply ensures all energy customers can decarbonise and is key to a future made in Australia. Gas power generation (GPG) will also play a vital role in firming renewable generation on the pathway net zero electricity supply.

When considering policy support, the Federal Government can learn from the policies which have worked to enable electricity decarbonisation. Certification and NGER recognition, target setting and contract for difference schemes have driven the energy transition to date and provide an excellent basis for its acceleration through gas and liquid fuels and GPG support.

Decarbonising gas and liquid fuel supply

Decarbonising gas and liquid fuels is critical for the economy. Gas accounts for 24% of all end-use energy consumption in Australia and is a critical input to Australian industry, mining and manufacturing.

Low-cost gas transport and storage infrastructure and low-cost gas appliances are part of the reason customers choose natural gas today. These low-cost advantages are also available to the renewable gas supply chain as it develops:

- Existing gas infrastructure costs less than electricity infrastructure, can deliver biomethane today, and can deliver 100% hydrogen with minimal additional cost[1].
- New renewable gas transport and storage infrastructure cost less than new electricity transport infrastructure and mature electricity storage options[1].
- Biomethane and hydrogen appliances cost less than their electric equivalents[1].

Some gas customers will have no option other than to decarbonise via renewable gas. Economic analysis by ACIL Allen indicates a minimum of 210PJpa of renewable gas is required to decarbonise industrial gas customers alone. More than this will be required to enable future expansion of Australian manufacturing and the production of green export products.

The policy focus areas identified for liquid fuels in Section 4.7 of the consultation paper can also be applied to decarbonising gas supply. The table below maps these policy focus areas to the gas supply chain. Consideration of renewable gas policy opportunities within this framework shows that in some regards, policy change to enable renewable gases is already underway. However, further policy support to decarbonise our gaseous fuel mix is required.

[1] See Section 1.1 of this submission for further details.

Table E1. Renewable gas policy focus areas and associated policy actions

Policy focus areas	1. Decarbonise our gaseous fuel mix	2. Reduce fossil gas demand	3. Ensure gas security and reliability	4. Manage supply chain vulnerabilities
Reason:	Driving renewable gases supports decarbonisation efforts and de-risks gas supply through diversification	Improving energy efficiency and promoting behavioural change reduces emissions and gas demand	Leveraging existing gas security and reliability of supply legislation will ensure climate and energy objectives are met through the transition	Existing mechanisms to address gas supply chain disruptions ensures government and industry can quickly respond to emerging gas supply chain risks
Renewable Gas Policy Action:	- An NGER market-based accounting method for gas emissions - A National Renewable gas target as part of the Future Gas Strategy (FGS) - Federal contracts for difference for renewable gas supply	- Increase gas appliance efficiency floor via existing NEPS process [UNDERWAY[2]]	- Expand existing gas security and reliability of supply legislation to cover renewable gases [COMPLETED[2]]	- Expand existing mechanisms to address gas supply chain disruptions to renewable gases [COMPLETED[2]]

Gas enables net zero electricity in Australia

Today's gas supply chain helps keep electricity prices low and reliability and security high. It does so by fuelling GPG and taking much of Australia's seasonally variable energy load off the electricity grid – most of Australia's winter heating is powered by gas. Gas can continue to support electricity reliability and security as both energy systems decarbonise together. However, policy support is required.

The Draft 2024 ISP clearly sets out the role of GPG in a decarbonised National Electricity Market:

> *As Australia's coal-fired generators retire after decades of service, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation (GPG) is the lowest cost way to supply electricity to homes and businesses.*[3]

Despite this, GPG is excluded from the Capacity Investment Scheme (CIS). This impedes the investment in GPG needed to secure the lowest cost pathway to 82% renewable electricity supply according to AEMO.

GPG support aside, policy support to enable renewable gas supply will support a decarbonising gas system, in turn reducing the load on a future net zero NEM.

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[2] See Section 1.3 of this submission for further details.
[3] AEMO, 2024, *Draft 2024 Integrated Systems Plan*, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/draft-2024-isp.pdf

Policy recommendations

APGA recommends the Department undertake modelling on the least cost pathway to gas use decarbonisation in Australia to inform renewable gas policy. Based upon industry analysis and AEMO recommendations relating to GPG, APGA proposes four policy recommendations across the immediate and medium term.

Immediate term policy recommendations

Policy action APGA recommends the EESP identifies for immediate action:

NGER market-based method for gas emissions accounting
GreenPower renewable gas certificates are being issued today, but NGER does not recognise these. Recognising GreenPower and future renewable gas certificates in NGER emissions accounting is critical to unlocking tens of petajoules of renewable gas production projects reaching FID in the near term.

GPG support via the CIS or analogous support mechanism
Extend the CIS to include GPG or develop a similar scheme to provide the long-term investment signals necessary to support investment in GPG capacity.

Medium term policy recommendations

Policy action APGA recommends the EESP identifies for medium term action:

A national Renewable Gas Target
Targeting the least cost pathway to net zero gas sets national gas decarbonisation ambition and strong industrial reliance on renewable gas makes a national RGT no-regrets policy.

Contracts for Difference for renewable gas supply
Renewable gas certification and recognition in NGER is the first step in starting a renewable gas industry today. The Hydrogen Headstart program is an excellent start but more must be done to ensure availability of large volumes of renewable gas including biomethane. Renewable gas Contract for Difference schemes could be used to ensure the cost of biomethane does not exceed the cost of natural gas for consumers today.

To discuss any of the details within this submission further, please contact APGA's National Policy Manager, Jordan McCollum, on +61 422 057 856 or jmccollum@apga.org.au.

About

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure, connecting natural and renewable gas production to demand centres in cities and other locations across Australia. Offering a wide range of services to gas users, retailers and producers, APGA members ensure the safe and reliable delivery of 28 per cent of the end-use energy consumed in Australia and are at the forefront of Australia's renewable gas industry, helping achieve net-zero as quickly and affordably as possible.

APGA supports a net zero emission future for Australia by 2050[4]. Renewable gases represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. As set out in Gas Vision 2050[5], APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC[6], which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy to homes, businesses, and industry throughout Australia.

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[4] APGA, *Climate Statement*, available at: https://www.apga.org.au/apga-climate-statement
[5] APGA, 2020, *Gas Vision 2050*, https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[6] Future Fuels CRC: https://www.futurefuelscrc.com/

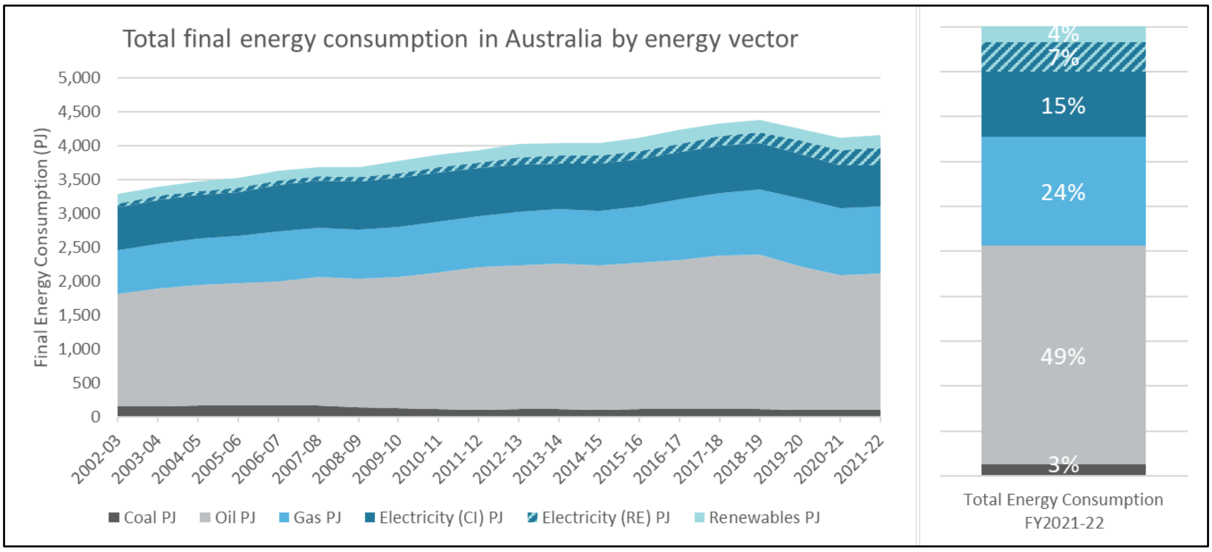
1 Decarbonising gas and liquid fuel supply

The EESP Discussion Paper takes Australia forward in its energy decarbonisation journey by committing an entire section to alternative low carbon fuels. Doing so highlights the need to decarbonise gas and liquid fuel supply chains. While both energy types are on their own decarbonisation journeys, similarities between the two mean that learnings from the decarbonisation of one can inform how best to decarbonise the other.

Over 75% of Australia's energy demand is consumed directly as fossil fuels[7] (Figure 1). Many of these direct fuel consuming energy customers are unable to electrify their energy demand – and a majority of these are the industrial energy customers upon which the Australian economy relies[8]. Gas and liquid fuel supply have renewable alternatives that must be deployed to achieve net zero:

- Natural gas has renewable gas alternatives such as biomethane and hydrogen.
- Liquid fuels have renewable liquid fuel alternatives such as bioethanol and renewable diesel.

Figure 1: Total final energy consumption in Australia by energy vector[9]



Accelerating the decarbonisation of existing gas and liquid fuel energy supply chains via alternative low carbon fuels will ensure these energy customers remain part of the Australian economy. They can continue to mine our resources, process our materials, make our products, and provide the jobs and economic activity that keeps the Australian economy vibrant and successful. Section 1.1 shows that the ability to use the lower cost infrastructure and appliances to transport, store and use fuels can help reduce the cost of an otherwise electricity – only energy transition.

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[7] DCCEEW, 2023, *Australian Energy Update 2023*, https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Update%202023_0.pdf

[8] Grattan Institute, 2021, *Towards net zero: Practical policies for reducing industrial emissions*, https://grattan.edu.au/wp-content/uploads/2021/08/Towards-net-zero-Practical-policies-to-reduce-industrial-emissions-Grattan-report.pdf

[9] DCCEEW, 2023, *Australian Energy Update 2023*.

Robust renewable fuels supply chains support a more secure and reliable energy system in a net zero future[10]. This makes renewable fuels essential to underpinning a future made in Australia. Secure and reliable carbon neutral energy of all forms will be required to re-align Australia's economy towards carbon neutral advanced manufacturing. Without a competitive supply of renewable fuels, Australia risks significant carbon leakage as industry chooses to relocate rather than decarbonise.

Beyond achieving net zero for today's gas customers, putting gas supply on its own decarbonisation journey also enables broader decarbonisation in the immediate term. Once gas is on a pathway to net zero, existing coal and liquid fuel customers can achieve immediate short-term emission reductions by transitioning to natural gas today, knowing natural gas will transition to renewable gas tomorrow.

This makes coal and liquid fuel emissions reduction cheaper and easier in the near term, accelerating decarbonisation in the decade to 2035. An example of this can be seen in BlueScope, Rio Tinto and BHP pursuing Direct Reduced Iron (DRI) technologies to replace coal supply in the short term with natural gas, and in the long term with hydrogen[11] (Figure 2). BHP is also transitioning from diesel to gas powered generation to firm variable renewable generation[12]. The opportunity to more rapidly decarbonise beyond today's gas customers makes renewable gases a priority within the EESP.

Figure 2: Excerpt from BlueScope 2023 Sustainability Report

Iron and steelmaking transformation

BlueScope's indicative decarbonisation pathway has been updated to reflect our refreshed assessment of technology developments in DRI, using natural gas as a transitional step to green hydrogen to produce lower emissions steel. This assessment was informed by our concept study with Rio Tinto to explore DRI and its application to Australia's Pilbara hematite ores in conjunction with Electric Smelting Furnaces[1] (ESF), known as 'Melters'. The study is now complete and the next stage of activity will include trials and a potential pilot program.

Further development of the use of hematite ores in a DRI-ESF process would unlock opportunities for the steel sector and the minerals sector as part of the transition to lower emissions iron and steelmaking, given their abundant availability, compared to higher grade ores typically required for the DRI process.

[10] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context* available at https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/pipelines_vs_powerlines_-_a_technoeconomic_analysis_in_the_australian_context.pdf

[11] Bluescope, 2023, *Sustainability Report FY2023,* https://www.bluescope.com/content/dam/bluescope/corporate/bluescope-com/sustainability/documents/2023_BlueScope_Report_Sustainability_Report.pdf; Fuller K, 2024, 'BlueScope, Rio Tinto and BHP join forces on plan for low carbon steel future', in *ABC News Illawarra*, https://www.abc.net.au/news/2024-02-09/green-steel-push-bluescope-bhp-rio-tinto-join-forces-carbon-plan/103447174

[12] BHP, 2023, *Operational decarbonisation*, https://www.bhp.com/-/media/documents/media/reports-and-presentations/2023/230621_operationaldecarbonisationinvestorbriefing.pdf

1.1 The advantage of gas supply chains

All natural and renewable gas supply chains benefit from the advantages of gas infrastructure and appliances. The simple, flexible nature of pipeline infrastructure makes it a cost-effective way to not only transport energy, but store energy within transmission infrastructure. As a result, natural gas remains lower cost for customers to use today in comparison with other options – even when piped thousands of kilometres across the country.

Similarly, appliances that use natural or renewable gases are cheaper than their alternatives. This lower upfront cost can make up for their energy efficiency which is inherently lower than heat pumps. Higher energy consumption through lower cost appliances can lead to lower cost of energy and appliances combined[13].

These advantages means that renewable gases can not only serve those gas customers with no other decarbonisation choice, but they can do so at a cost competitive with renewable electricity[13]. To understand the cost of decarbonisation for energy customers through alternative low carbon fuels, it is necessary to consider the cost effectiveness of energy transport, storage and appliances alongside the cost effectiveness of energy production.

1.1.1 Existing gas infrastructure

Direct comparison of like-for-like gas and electricity infrastructure demonstrates that gas infrastructure consistently costs less when providing equal or higher supply capacity. This is why gas infrastructure draws lower revenues from customers.

Table 1 and Table 2 below demonstrate comparisons of the regulated asset bases (RABs) of comparable gas and electricity infrastructure in Victoria and the ACT.

Table 1: Costs and deliveries of Victoria's energy infrastructure[14]

Transmission and Distribution Infrastructure	Regulated Asset Base ($m)	Actual Annual Revenues ($m)	Actual Energy Delivered (GWh)	Max Demand Capacity (MW)
Electricity	17,329	2,825	41,480	8,684
Gas	5,631	774	64,722	23,250

[13] Boston Consulting Group, 2023, *The role of gas infrastructure in Australia's energy transition*, https://39713956.fs1.hubspotusercontent-na1.net/hubfs/39713956/The-Role-of-Gas-Infrastrcuture-in-Australia-s-Energy-Transition.pdf

[14] APGA, 2021, *Submission: Victorian Gas Substitution Roadmap Consultation Paper*, https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/210816_apga_submission_to_the_victorian_gas_substitution_roadmap_consultation_paper.pdf

Table 2: Relative cost of energy delivery for gas and electricity distribution in the ACT[15]

Energy distribution networks	Regulated asset base ($m)	Actual annual revenues ($m)	Actual energy delivered (GWh)	Average cost to deliver a GWh ($)
Electricity	981	140	2,851	49,106
Gas	377	67	2,201	30,436

In Victoria, the RAB of gas transmission and distribution infrastructure is a third of the size of that of electricity infrastructure, but delivers a third more energy, and can support peak demand 60% higher. Relevant to customer interests, gas infrastructure also generates only 27% of the revenue of electricity, which is related both to the capital cost of the infrastructure and ongoing operational expenditure. Similarly, ACT gas infrastructure delivers 80% of the capacity of electricity infrastructure at 40% of the cost.

Analysis by the ARENA-funded Australia Hydrogen Centre further shows that the cost of converting gas infrastructure to deliver 100% hydrogen comes at a fraction of gas asset RAB. Analysis on South Australian and Victorian gas distribution networks shows that conversion of the gas network and all gas appliances to 100% hydrogen would increase distribution network stay-in-business capital expenditure to 2050 by 11-12% in present value terms[16]. This small cost of conversion indicates that today's low cost of gas infrastructure will be retained when delivering renewable gases, even hydrogen, through existing gas infrastructure.

1.1.2 New gas infrastructure

Where new energy transport and storage infrastructure is required, pipeline infrastructure is a cost competitive option. This has been shown through recent pipeline and powerline infrastructure projects:

- APA's 50km Western Outer Ring Main pipeline was completed in 2024 for approximately $185 million, or $3.7 million per kilometre. This project was in an urban environment, significantly adding to cost.
- APA's $560km Northern Gas Interconnect was completed in 2023 for a cost of $821,000 per kilometre.
- AGIG's 440km Tanami Natural Gas Pipeline, completed in 2019, cost $346 million or $786,000 per kilometre.

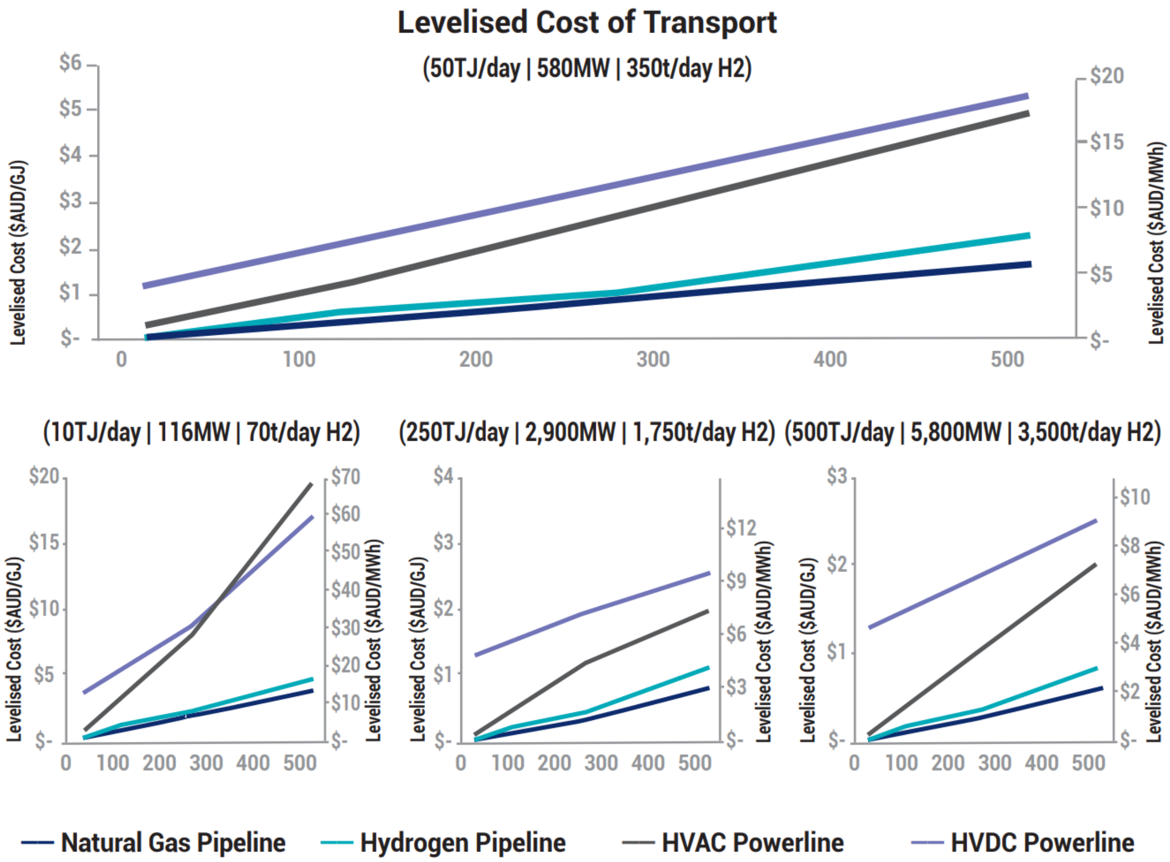
[15] APGA, 2023, *Submission: Regulating for the prevention of new fossil fuel gas network connections*, https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/230420_apga_submission_-_act_gas_connections.pdf

[16] Australian Hydrogen Centre, 2023, *100% Hydrogen Distribution Networks: Victoria Feasibility Study*, https://arena.gov.au/assets/2023/09/AHC-100-Hydrogen-Distribution-Networks-Victoria-Feasibility-Study.pdf; Australian Hydrogen Centre, 2023, *100% Hydrogen Distribution Networks: South Australia Feasibility Study*, https://arena.gov.au/assets/2023/09/AHC-100-Hydrogen-Distribution-Networks-South-Australia-Feasibility-Study.pdf

- The 360km HumeLink overhead transmission powerline project is expected to cost approximately $4.8 billion, or $13.3 million per kilometre.
- The proposed 400km Victoria – New South Wales Interconnector West overhead transmission project is expected to cost approximately $3.3 billion, or $8.25 million per kilometre. There are numerous reports that this cost will increase.

GPA Engineering's *Pipelines vs Powerlines* report provides further details on this relationship[17]. Both gas and hydrogen transmission pipelines consistently cost less to deliver the same quantity of energy across the same distance in comparison to electricity transmission powerlines. An example of this relationship can be seen in Figure 3, outlining the cost of energy transport for a range of energy capacity scenarios over 500km. This outcome has since been supported by academic research within the Future Fuels CRC.

Figure 3: Levelised cost of energy transport via pipelines and powerlines[18]

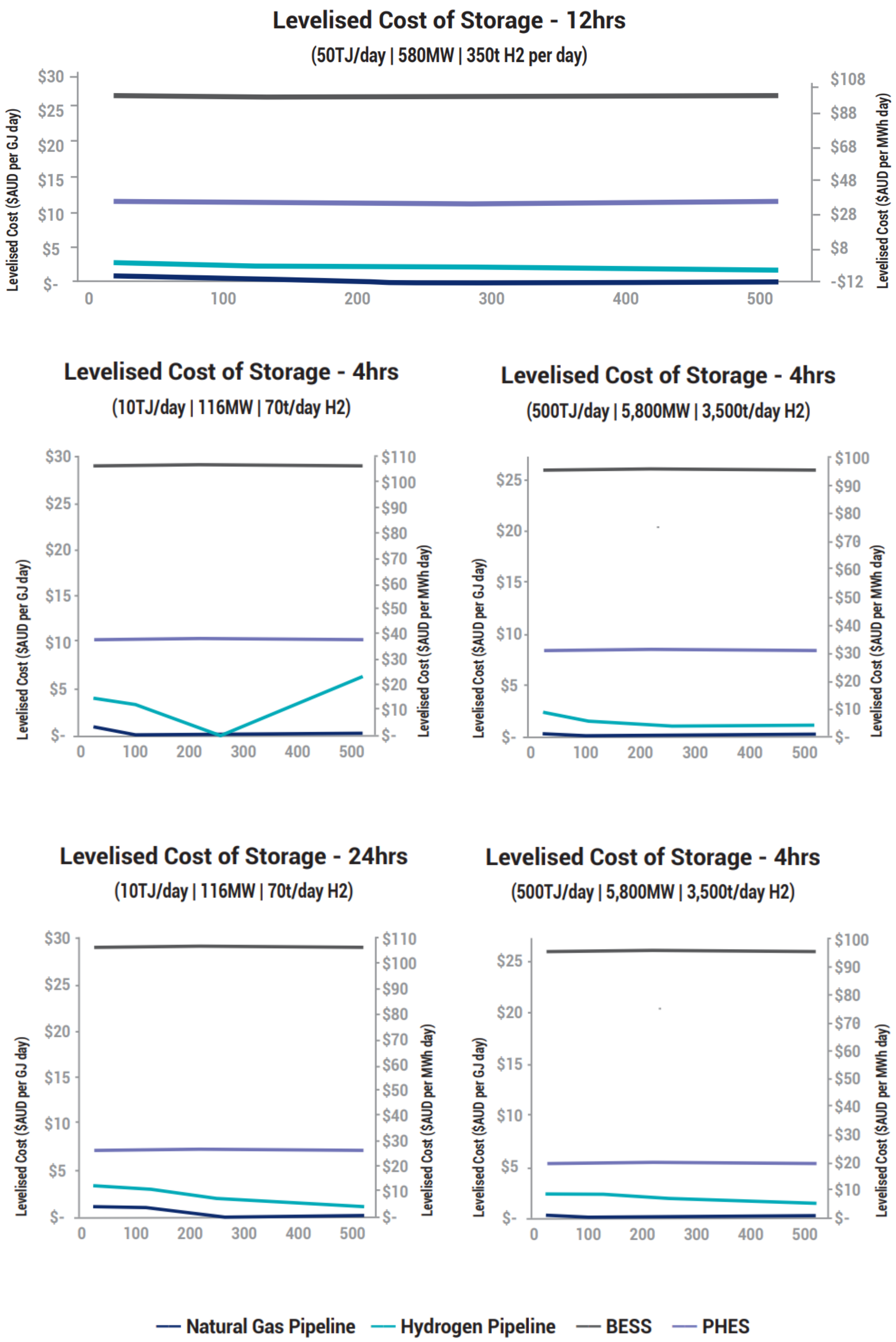


The economic benefits of new pipeline infrastructure extend beyond transport. GPA Engineering's research also examined the levelised cost of energy storage between pipelines and battery (BESS) and pumped hydro (PHES) energy storage solutions, finding that energy storage in pipelines can be hundreds of times cheaper than energy storage in utility scale batteries or pumped hydro (Figure 4). GPA Engineering found that energy

[17] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.
[18] Ibid.

storage in hydrogen pipelines can be 2-to-36 times cheaper than energy storage in utility scale batteries or pumped hydro, excluding the instances in which it is essentially free.

Figure 4: Levelised cost of energy storage via pipeline linepack, BESS and PHES



1.1.3 Gas and hydrogen appliances

The technical simplicity of combusting gas makes gas and hydrogen appliances a cost-effective option in the majority of applications gas is used for today. Collating appliance cost assumptions for its economic analysis, ACIL Allen identified (Figure 5) that gas or hydrogen appliances were the equal or lowest cost appliance option for over three quarters of applications gas use used for today[19].

Considering the cost of decarbonising gas use, both energy cost and appliance cost needs to be taken into account. Focusing on only appliance cost or energy cost could lead to inaccurate conclusions being made about the least cost decarbonisation pathway.

Figure 5: Appliance capital cost and operating life assumptions[20]

		Capital cost			Appliance life (years)	
Activity (by size)	Capital cost unit basis	Natural gas appliance	Electrical appliance	Hydrogen appliance	Gaseous fuels appliance	Electrical appliance
Low temperature heat	$\$m/MW_{th}$	0.5	1.3	0.65	20	15
High temperature heat (small)	$\$m/MW_{th}$	0.4	0.4	0.5	25	25
High temperature heat (medium)	$\$m/MW_{th}$	0.3	0.3	0.4	25	25
Metal reheat (small)	$\$m/MW_{th}$	0.5	1.7	0.7	20	15
Metal reheat (medium)	$\$m/MW_{th}$	0.3	1.5	0.4	20	15
Compression (medium)	$m/MW	6.4	7.8	6.4	25	25
Compression (large)	$m/MW	3.5	4.3	3.5	25	25
Glass making	$\$m/MW_{th}$	1.5	1.5	1.6	20	20
Calcining (medium)	$\$m/MW_{th}$	1.5	N/A	1.6	30	30
Calcining (large)	$\$m/MW_{th}$	1.5	N/A	1.6	30	30
Digestion	$\$m/MW_{th}$	0.3	1.7	0.4	20	15
Ammonia synthesis	$m/ktpa (capacity)	1.9	N/A	1.5	25	25
Urea	$m/ktpa (capacity)	2.7	N/A	0.8	25	25
LNG power generation	$m/MW	1.5	0.2	N/A	25	40
Commercial cooking	$\$m/MW_{th}$	0.2	0.3	0.3	20	15
Commercial hot water	$\$m/MW_{th}$	0.8	1.3	0.9	15	15
Commercial space heating	$\$m/MW_{th}$	0.5	0.8	0.5	20	15
Residential cooking - existing	$000/ appliance	2.0	2.7	2.2	20	15
Residential hot water - existing	$000/ appliance	3.2	2.9 (resistive) 5.4 (heat pump)	3.6	15	15

[19] See Attachment 1
[20] See Attachment 1; note there is more appliance cost detail in Attachment 1 then shown in this document.

1.2 Economic analysis of gas use decarbonisation

To assist gas customers to decarbonise, APGA and Energy Networks Australia (ENA) commissioned ACIL Allen to undertake economic analysis of gas use decarbonisation. A copy of the study is attached to this submission and APGA invites further conversation on this study and its implications. This section will explore analysis outcomes for the following topics:

- Renewable gas supply for gas customers which have no option to electrify
- Gas use decarbonisation at lowest overall cost
- Policy to deliver gas use decarbonisation at lowest overall cost.

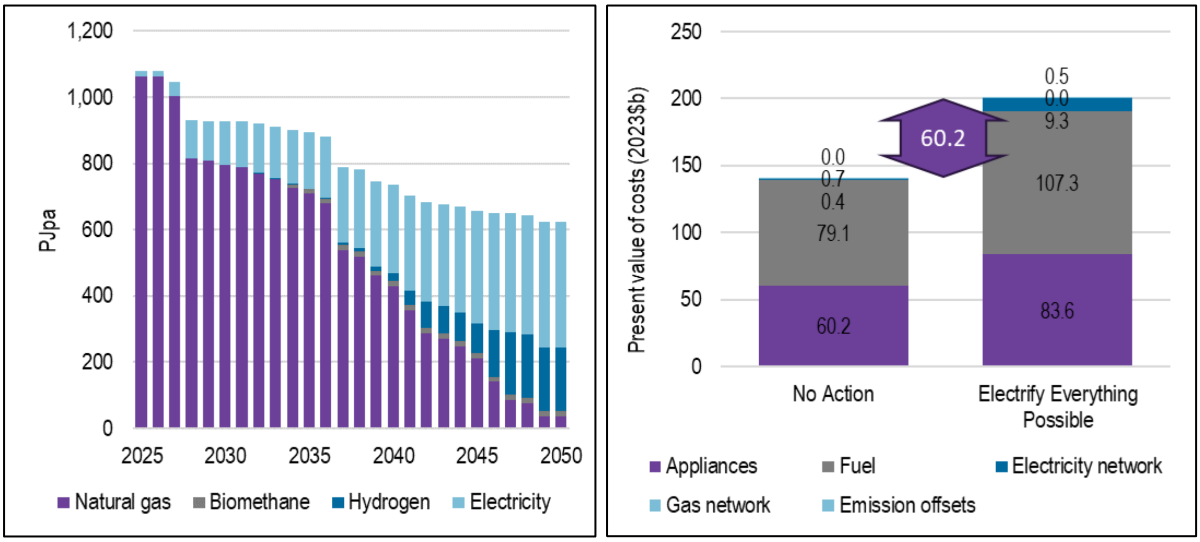
Beyond considering these results, APGA strongly recommends that the Department replicates the modelling approaches seen within this study to assess policy options to deliver gas use decarbonisation at lowest overall cost.

1.2.1 Renewable gas supply for gas customers which cannot electrify

The analysis considered the least cost pathway to decarbonise gas use, while reserving renewable gases for those who cannot electrify. In this Electrify Everything Possible (EEP) scenario, all domestic gas customers which could electrify – i.e. have an electric appliance option – were required to electrify in order to decarbonise. The least cost decarbonisation trajectory was calculated in line with a net zero carbon budget.

Figure 6 below shows that the result is a steady electrification of gas demand over the window to 2050, with 210PJpa worth of renewable gases being required decarbonise customers unable to electrify.

Figure 6: EEP scenario – energy supply breakdown and cost comparison[21]



[21] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, commissioned by APGA and ENA.

This demonstrates that a combination of renewable gas and renewable electricity is needed to decarbonise gas demand in Australia.

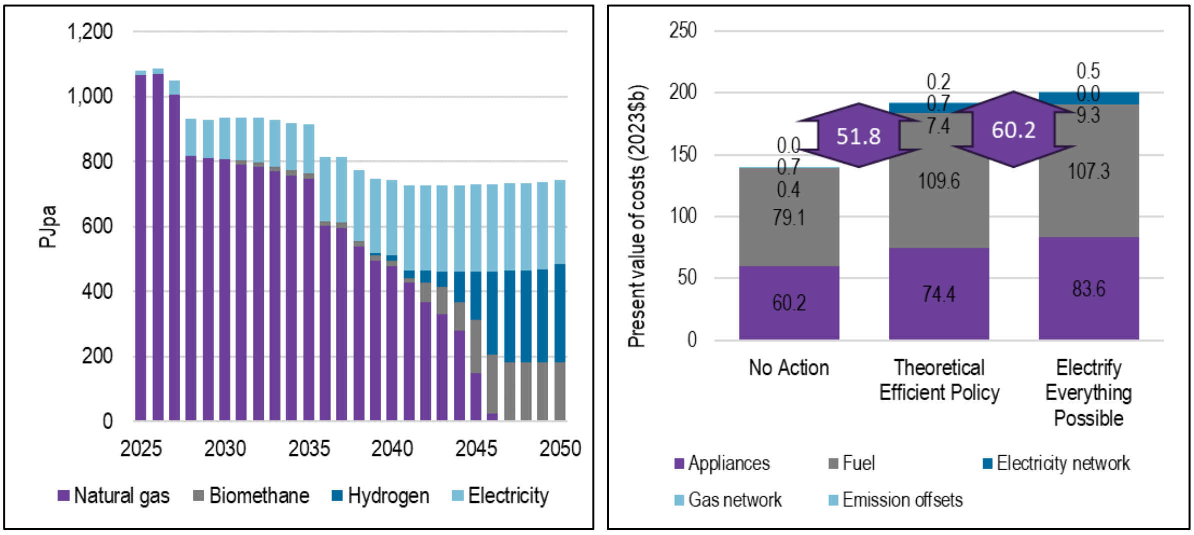
Unsurprisingly, this analysis also confirms that gas use decarbonisation will cost customers and the economy more than maintaining the carbon intensive status quo. Continuing to supply gas customers with natural gas through 2050 will require additional production and appliance replacement investments of around $140bn ($2023) through to 2050. Alternately, electrifying everything possible and supplying renewable gases to remaining gas customers is calculated to cost an additional $60.2bn ($2023), resulting in an average cost of abatement of around $165/t$CO^2$e.

1.2.2 Gas use decarbonisation at lowest total cost

Public sentiment analysis indicates that the majority of Australian energy consumers are sensitive to the costs of decarbonisation[22]. Australian business representatives share this sentiment[23]. While the above EEP scenario requires customers electrify if they can, ACIL Allen also modelled the prospect that renewable gases could be a lower cost option for some customers.

Figure 7 shows the result of the Theoretically Efficient Policy (TEP) scenario, in which decarbonisation was guided by only the cost of energy and appliances and the same net zero carbon budget.

Figure 7: TEP scenario – energy supply breakdown and cost comparison[24]



These two charts show that without the requirement to electrify everything possible, the model selects renewable gas options in many applications. The lowest cost outcome was

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22 RedBridge, 2024, *EnergyShift Australia*, commissioned by APGA, https://apga.org.au/research-and-other-reports/energyshift-australia

23 Victorian Chamber of Commerce and Industry, 2024, *Gas: a burning issue*, https://www.victorianchamber.com.au/news/gas-a-burning-issue

24 ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, commissioned by APGA and ENA.

delivered using around 480PJpa of renewable gases and 260PJpa of renewable electricity in 2050.

This scenario reduces the additional cost to decarbonise by 14% to $51.8bn ($2023). Important to note is that the ratio of energy and appliance costs differ in this scenario – lower appliance costs in this scenario indicate a lesser burden being put on customers to finance the energy transition through their own, typically higher cost capital.

This outcome accords with the principles of market economics, where providing more options to achieve an outcome often results in lower costs overall. However, the implication is profound for the energy transition. Comparing the EEP and TEP scenarios indicates:

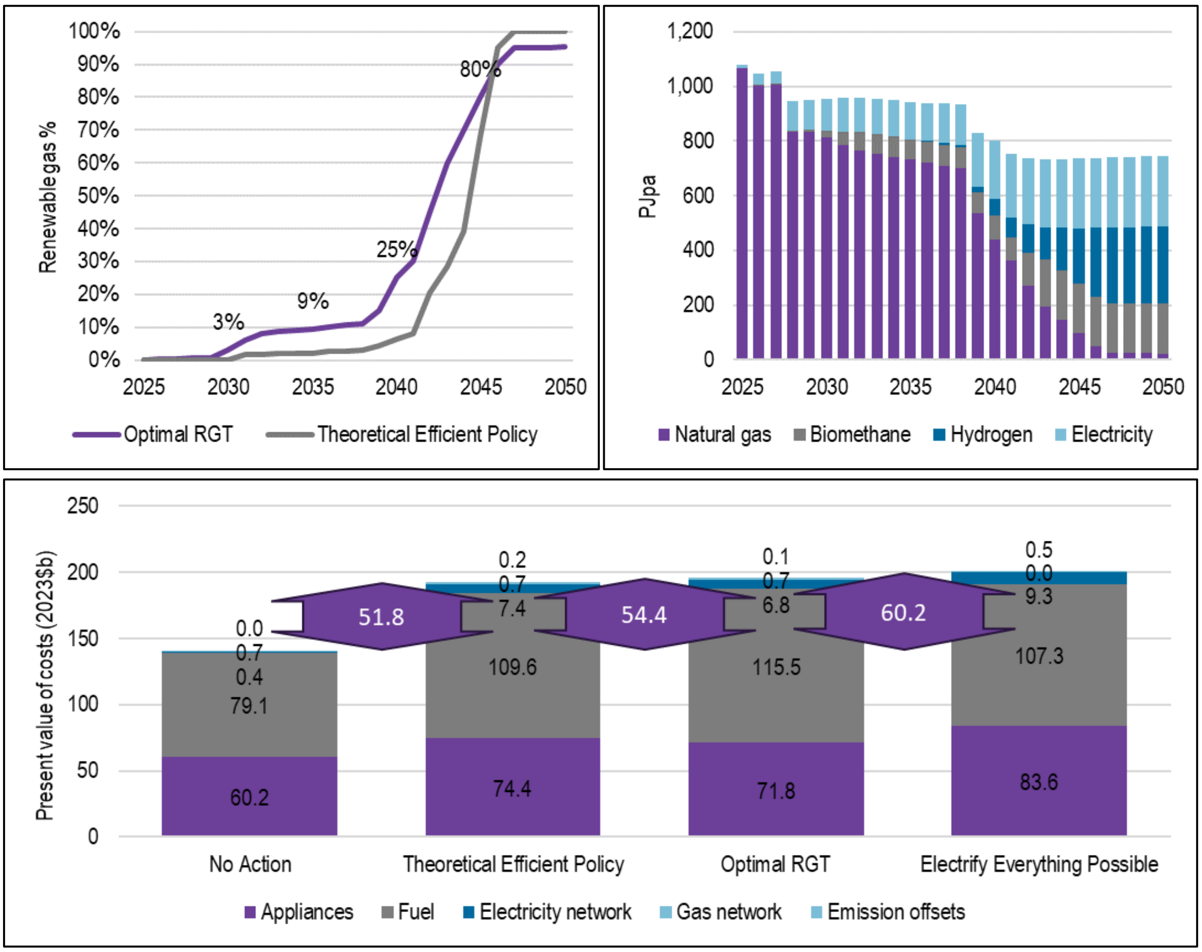
1. Not allowing customers to choose the decarbonisation solution which suits their unique circumstances will increase the cost of the transition.
2. There are gas customers which physically can electrify but could decarbonise through renewable gas purchases for lower cost.
3. Policy supporting renewable gas production is critical to delivering gas use decarbonisation at least cost, rather than at any cost.

1.2.3 Policy to deliver the least cost gas use decarbonisation pathway

While the TEP scenario demonstrates the least cost transition pathway for gas use decarbonisation, it does not represent practical policy solution to implement. Instead, it reflects a pathway achieved through perfect foresight and timing of investments. The TEP is equivalent to introducing a carbon trading scheme with unlimited banking and borrowing.

The Optimal Renewable Gas Target (RGT) was designed to deliver a practically implementable policy and based on past successful Australian energy policy (Figure 8). The intent of this scenario is to set targets of renewable gas as a percent of total gas demand between 2030 and 2050, which marginally brings forward renewable gas production, brings forward cost reduction learnings and flattens development costs in the 2040s.

Figure 8: Optimal RGT – RGT trajectory, energy supply breakdown and cost comparison[25]



The charts in Figure 8 show that by marginally bringing forward renewable gas supply, the Optimal RGT scenario secures gas use decarbonisation in line with the TEP scenario, while marginally increasing costs. Importantly, every gas customer for which it is lower cost to electrify is still able to choose to electrify under the Optimal RGT scenario.

The Optimal RGT scenario is not burdened with the same restrictions that increase cost in the EEP scenario. This scenario maintains the ability for customers to choose which decarbonisation option best suits their unique circumstances, and so reduces the cost of transition. The Optimal RGT scenario also results in lower appliance cost. This means that less of the capital cost burden of the transition falls on consumers.

1.2.4 Importance of economic efficiency when decarbonising gas

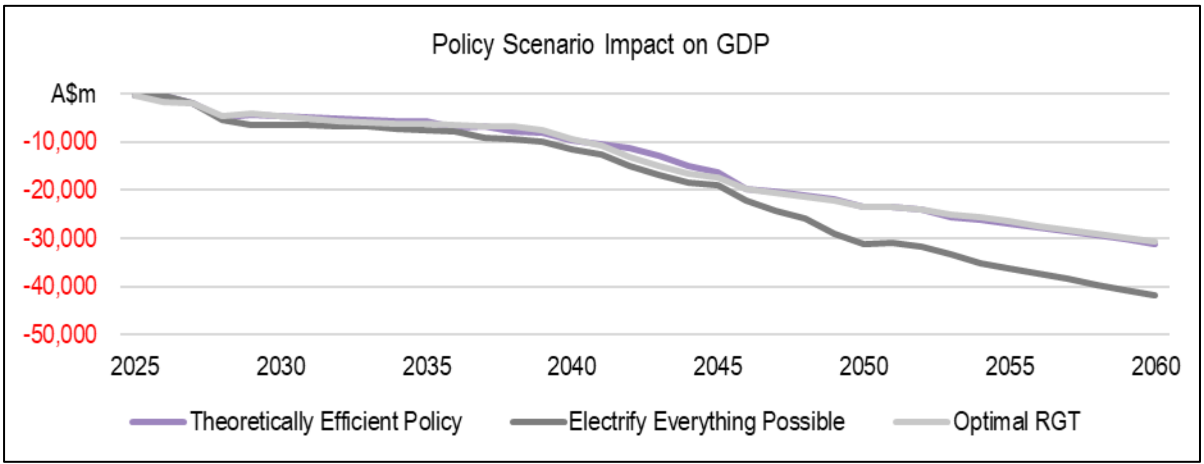
All gas use decarbonisation cases considered in ACIL Allen modelling have a higher resource cost compared to simply continuing to use natural gas. The differences in these higher costs is important when considering the impact of the transition on Gross Domestic Product (GDP).

[25] ACIL Allen, 2024, *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy*, commissioned by APGA and ENA.

When considering gas decarbonisation at a macroeconomic level, the higher cost of the EEP scenario is amplified. Relative to the least cost TEP scenario, the EEP scenario is 11 times more costly to GDP (-$33bn in $2023) than the Optimal RGT scenario (-$3bn in $2023) (Figure 9). This highlights the importance of economically efficient energy policy as any inefficiencies at the microeconomic level are amplified at the macroeconomic level.

Figure 9: Impacts of gas decarbonisation policy choices on GDP

Scenario	Emissions (2025-2060)	Present value of resource cost (2020-2060)	Abatement cost	Change in real economic output (GDP) relative to No Action scenario (2020-2060)	Change in GDP relative to Theoretical Efficient Policy scenario (2020-2060)
	Mt CO_2-e	$b	$/tonne CO_2-e	$b	$b
No Action	1,591	$140			
Theoretical Efficient Policy	724	$192	$143	-$121	$0
Electrify Everything Possible	729	$201	$165	-$154	-$33
Optimal RGT	722	$195	$150	-$124	-$3



1.3 Policy support for gas use decarbonisation

The policy focus areas identified for decarbonising liquid fuels in Section 4.7 of the Discussion Paper can be applied to decarbonising gas supply. Each of the four areas are equally applicable to the renewable gas transition as the renewable liquid fuel transition. Table 3 below maps these policy focus areas to the gas supply chain, including policy actions proposed by APGA.

APGA recommends that the EEPS take the same approach to policy focus areas to enable renewable gases.

Table 3: Renewable gas policy focus areas and associated policy actions

Policy focus areas	1. Decarbonise our gaseous fuel mix	2. Reduce fossil gas demand	3. Ensure gas security and reliability	4. Manage supply chain vulnerabilities
Reason:	Driving renewable gases supports decarbonisation efforts and de-risks gas supply through diversification	Improving energy efficiency and promoting behavioural change reduces emissions and gas demand	Leveraging existing gas security and reliability of supply legislation will ensure climate and energy objectives are met through the transition	Existing mechanisms to address gas supply chain disruptions ensures government and industry can quickly respond to emerging gas supply chain risks
Renewable Gas Policy Action:	- NGER market-based accounting method for gas emissions - A national Renewable gas target in the FGS - Federal contracts for difference for renewable gas	- Increase gas appliance efficiency floor via existing NEPS process [UNDERWAY[26]]	- Expand existing gas security and reliability of supply legislation to cover renewable gases [COMPLETED[27],[28]]	- Expand existing mechanisms to address gas supply chain disruptions to renewable gases [COMPLETED[27,29]]

In some regards, the decarbonisation of gas supply is ahead of liquid fuels. Amendments passed in 2023 extended the National Gas Law (NGL) to renewable gases, extending recent supply security and reliability reforms to renewable gas supply. This ensures that gas security and reliability is maintained and supply chain vulnerabilities are managed. The recently published National Energy Performance Strategy (NEPS) includes consideration of gas appliance efficiency which will support reducing fossil-based gas demand. Decarbonising Australia's gas supply is the logical next step.

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[26] DCCEEW, 2024, *National Energy Performance Strategy*, https://www.dcceew.gov.au/energy/strategies-and-frameworks/national-energy-performance-strategy

[27] DCCEEW, 2023, *Extending the national gas regulatory framework to hydrogen and renewable gases*, https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/extending-national-gas-regulatory-framework-hydrogen-and-renewable-gases

[28] AEMO, 2023, *East Coast Gas Reforms*, https://aemo.com.au/en/initiatives/major-programs/east-coast-gas-reforms

[29] Including through the National Gas Emergency Response Advisory Committee; see AEMO, 2024, *National role*, https://www.aemo.com.au/energy-systems/gas/emergency-management/national-role

1.3.1 Policy support to decarbonise our gaseous fuel mix

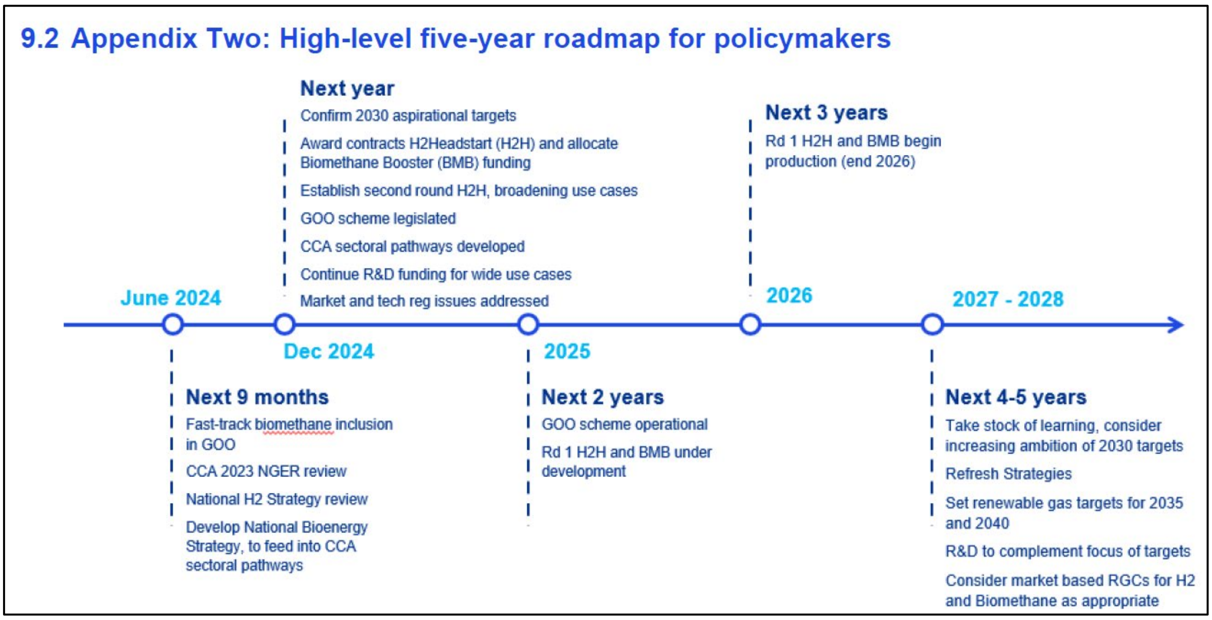
Analysis by KPMG of policy mechanisms supports the economic analysis of ACIL Allen by identifying past successful policy mechanisms which are appropriate to apply to the renewable gas challenge (Figure 10).

APGA identifies three policy mechanisms as being key to enable renewable gas to decarbonise gas use in Australia:

1. Immediate: Enabling renewable gas markets via NGER recognition of renewable gas certificates;
2. Medium term: Sending an investment signal through the introduction of an aspirational national Renewable Gas Target within Australia's emission targets; and
3. Longer term: Avoiding increased energy costs while ensuring targets are met through federally-funded contracts for difference (CfD) schemes targeting renewable gas costs above the cost of natural gas.

At a minimum, APGA recommends the Federal Government undertake modelling to inform its policy development, which considers least cost gas use decarbonisation similar to the ACIL Allen analysis.

Figure 10: KPMG High-level five-year roadmap for policymakers[30]



1.3.1.1 NGER recognition of renewable gas certificates

Renewable gases do cost more than natural gas. To justify paying a higher price, wholesale gas customers must be able to gain additional value beyond energy supply alone when purchasing renewable gas. The additional value which renewable gases can provide is through emissions reduction: the energy is provided at less than 1% of the scope 1

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[30] KPMG, 2023, *Renewable gas: policy options to support Australia's decarbonisation journey*, https://www.energynetworks.com.au/resources/reports/kpmg-report-policy-options-to-support-australias-decarbonisation-journey

emissions of natural gas. For customers to gain access to this value, the NGER Measurement Determination needs to be updated to include a market-based method for accounting for Scope 1 gas emissions.

This is not a new idea. Introduction of a market-based method for Scope 1 gas emissions was recommended by the Climate Change Authority in its December 2023 NGER review report[31]. Such a method already exists for scope 2 emissions accounting for renewable electricity certificates. Renewable gas industry and customers have been requesting this relatively simple policy change for some time – a change which is key to Safeguard Mechanism Facilities being able decarbonise through renewable gas supply.

A market-based method for gas could recognise the surrender of renewable gas certificates issued by Australian state or Federal governments, departments, or agencies. The GreenPower Renewable Gas Certification pilot is already producing Renewable Gas Guarantee of Origin (RGGO) certificates. This scheme could form a basis for design before the Federal Guarantee of Origin (GO) Scheme is finalised, or as an alternative to the GO Scheme.

Design for certificates beyond the GO Scheme is important. Currently, the design of the GO Scheme makes it impossible to integrate with Australia's facilitated gas markets[32]. Additionally, the GO Scheme does not consider biomethane -Australia's lowest cost renewable gas option. The GreenPower scheme does not have these issues.

1.3.1.2 A National Renewable Gas Target (RGT)

It is difficult to see how 2035 targets can be set without understanding the extent to which natural gas use will be decarbonised in the next decade. This makes a renewable gas target an essential input to 2035 economy wide target.

Setting ambitious decarbonisation targets has been a key policy mechanism used by Australian state and Federal governments. While the impact of the Renewable Energy Target (RET) on renewable electricity production makes it Australia's most successful target, more recent schemes indicate the value of simple, aspirational targets in framing renewable energy investment opportunities. As is the case with Australia's 82% by 2030 renewable electricity target, aspirational targets can also leverage government funding to drive public investment – as seen through the Capacity Investment Scheme.

Target Pathway
Through the *Optimal RGT* scenario, ACIL Allen identifies a National RGT pathway that secures a least cost gas use decarbonisation pathway. A National RGT design could be made simple yet agile by setting renewable gas quantity targets every five years, based on a

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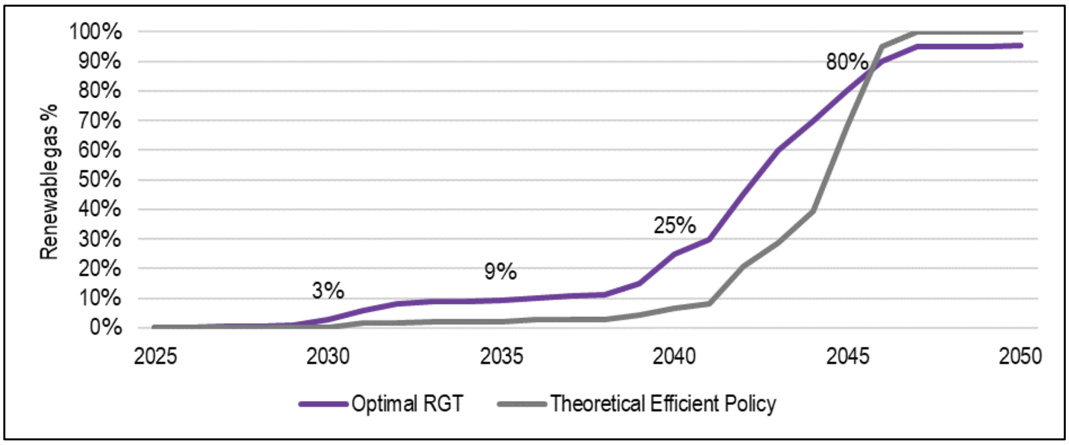
[31] Climate Change Authority, 2023, *2023 Review of the National Greenhouse and Energy Reporting Legislation*, https://www.climatechangeauthority.gov.au/sites/default/files/documents/2023-12/2023%20NGER%20Review%20-%20for%20publication.pdf
[32] APGA, 2023, *Submission: Guarantee of Origin Scheme Accounting*, https://apga.org.au/submissions/guarantee-of-origin-scheme-emissions-accounting; APGA, 2023, *Submission: Guarantee of Origin Scheme Design*, https://apga.org.au/submissions/guarantee-of-origin-scheme-design; APGA, 2023, *Submission: Australia's Guarantee of Origin Scheme*, https://apga.org.au/submissions/australias-guarantee-of-origin-scheme

desired renewable gas percentage of total gas supply (Figure 11). As seen through the RET, regular percentage-based quantity setting ensures that targets remain relevant to Australia's changing energy needs, avoiding over- or under-ambition.

Figure 11: Optimal RGT – Renewable gas target as a percentage of all gas consumption



Value of a National Target over state-based targets
ACIL Allen's renewable gas supply availability and cost findings demonstrate that not all states are equally abundant in renewable gas supply opportunities. However, both the operation of the east coast gas market and ACIL Allen's modelling shows that gases – including renewable gases – can be moved cheaply and efficiently between states. This is in part due to Australia's world class gas transmission pipeline infrastructure which transports gas across the country today.

This indicates that a National RGT can secure lower decarbonisation costs, compared to a state-by-state approach. This is a key reason why ACIL Allen's analyses and the Victorian Government's analyses differ – when only considering renewable gas supply *from* Victoria, the opportunity for renewable gas in Victoria looks much poorer than shown in national modelling.

1.3.1.3 Federally funded contracts for difference

All forms of gas decarbonisation cost more than remaining on natural gas. This must be addressed through the transition as decarbonisation will have cost implications across the economy. It is important that this fact does not prevent the first renewable gas production projects from reaching FID.

Federally-funded CfD, pinned to wholesale natural gas prices, could ensure renewable gas production projects are guaranteed the revenue they need to achieve FID while addressing the cost-of-living concern of potentially higher gas prices. This scheme would be consistent with the intent of the Made in Australia Act and could mirror other such schemes including the Capacity Investment Scheme.

2 Gas enables net zero electricity in Australia

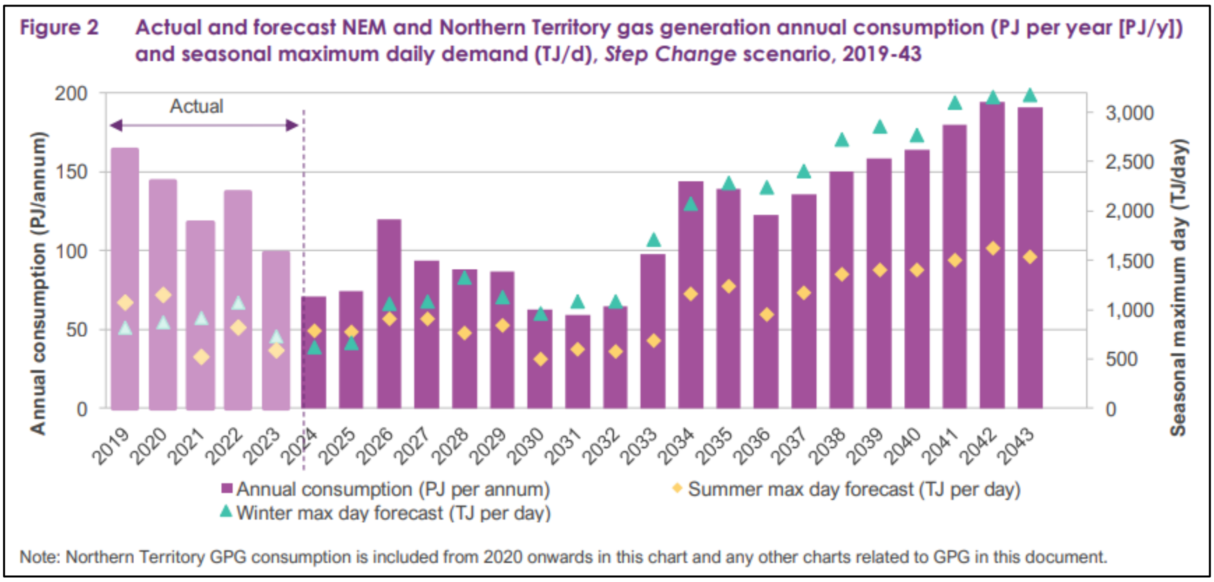
Today's gas supply chain helps keep electricity prices low and reliability and security high. This parallel energy supply chain does so directly by fuelling GPG, and indirectly by reducing electricity system load through supplying large volumes of energy to gas customers.

As Australia transitions towards net zero, a decarbonised gas supply chain can continue to perform this role. It can do so by firming variable renewable generation in a net zero NEM and reducing electricity system demand by supplying energy to those gas customers which need decarbonise via renewable gas for practical or economic reasons.

2.1 GPG helps Australia achieve net zero electricity

There is no doubt about the critical role that GPG plays in achieving net zero electricity in Australia. AEMO analysis shows over 4.4x the GPG capacity used in 2023 is required to supply winter peak demand in the 2040's in line with their net zero consistent Step Change scenario[33] (Figure 12). Analysis by Frontier Economics indicates that a net zero NEM can be achieved at least cost through 93% variable renewable generation and 7% GPG[34]. Frontier Economics also determined that GPG has whole of system cost (WESC) equal to or less than solar in a paper considering the impracticalities of levelised cost analysis in the transition to electricity systems with increasing levels of variable generation[35].

Figure 12: AEMO Gas Statement of Opportunities GPG Forecast



[33] AEMO, 2024, *2024 Gas Statement of Opportunities*, https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf

[34] Frontier Economics, 2021, *Potential for Gas-Powered Generation to support renewables*, commissioned by APGA, https://apga.org.au/research-and-other-reports/potential-for-gas-powered-generation-to-support-renewables

[35] Frontier Economics, 2021, *The role of gas in the transition to net-zero power generation*, commissioned by the Australian Gas Industry Trust and Jemena, https://apga.org.au/research-and-other-reports/the-role-of-gas-in-the-transition-to-net-zero-generation

Public sentiment analysis indicates that the majority of Australian energy consumers are sensitive to the costs of decarbonisation [36]. While it is technically possible to firm the NEM without GPG, it will be necessary to achieving net zero at least cost.

Importantly, GPG doesn't have to remain carbon intensive. Biomethane is 100% compatible with GPG today, and projects including the South Australian Hydrogen Jobs Plan Power Plant Project are on their way to Australian-first demonstrations of 100% renewable GPG. GPG remains a competitive firming option even with renewable gas prices as high as $50/GJ[37].

Without GPG, the NEM falls back on using the next most readily available generation source – coal fired generation. The fact that it is GPG being squeezed out of the NEM while coal generation remains competitive indicates the challenge of achieving lower emissions within the electricity market. Government policy is required to ensuring sufficient competitive GPG is brought online in time for the 2030s in order to avoid more circumstances in which state governments need to underwrite continued coal fired generation that is otherwise ready for retirement[38].

2.1.1 Policy support to ensure GPG investment

Despite this widely recognised and critical role, GPG has been omitted from the Capacity Investment Scheme (CIS). This creates an imbalance in investment incentives against GPG, which puts achieving a net zero NEM at risk. This is because this imbalance in investment incentives risks:

a) Driving investors in existing GPG out of the market; and
b) Deterring potential investors away from investing in the additional GPG the country needs to achieve net zero at least cost.

Including GPG into the CIS would be the simplest way to address this imbalance. Otherwise, a separate targeted scheme is required to ensure the necessary GPG capacity is delivered in time. This scheme could be designed to target delivery of the capacity requirements identified by AEMO's GSOO and/or ISP in the years before they are required.

[36] RedBridge, 2024, *EnergyShift Australia*, commissioned by APGA, https://apga.org.au/research-and-other-reports/energyshift-australia
[37] Gilmore J, Nelson T, Nolan T, *Firming technologies to reach 100% renewable energy production in Australia's National Electricity Market (NEM)*, https://www.energy.gov.au/sites/default/files/2022-02/Iberdrola%20Australia%20Response%20to%20Capacity%20Mechanism%20Project%20Initiation%20Paper%20-%20Attachment%201.pdf
[38] NSW Office of Energy and Climate Change, 2023, *Electricity Supply and Reliability Check Up: NSW Government Response*, https://www.energy.nsw.gov.au/sites/default/files/2023-09/Electricity_Supply_and_Reliability_CheckUp_NSW_Government_Response_September_2023.pdf; Office of the Premier of Victoria, 2023, *Agreement Secures Transition For Loy Yang A*, https://www.premier.vic.gov.au/agreement-secures-transition-loy-yang

2.2 Decarbonising gas supply takes pressure off a net zero NEM

A big part of achieving net zero electricity and ensuring reliability and security of supply is the scale of uplift required across the coming decades. The scale of change to the Australian electricity system is unprecedented. If there are options to reduce the strain on this system while still achieving a net zero outcome, other important outcomes including energy equity, reliability and security can be more easily achieved.

There is an opportunity for the resilience of a net zero NEM to be optimised by considering:

- Alternative energy infrastructure; and
- Reducing overall demand.

Alternative energy infrastructure

- The NEM is already the longest electricity transmission system in the world. Keeping costs low while maintaining reliability and security of supply, all while increasing variable generation and demand, will be a key challenge of the transition.
- More electricity storage and transmission powerlines will also increase the cost of the NEM, increasing bill costs. Any option to optimise energy infrastructure costs should be taken.
- The hydrogen supply chain can help optimise the electricity supply chain as energy transport and storage using hydrogen pipelines is cheaper than electric alternatives.

Reducing overall demand

- Today, gas and electricity systems share domestic energy demand at a ratio of 20% electricity and 24% gas.
- While many gas customers will electrify, other gas customers will need to stay on the gas system as it decarbonises for practical or economic reasons.
- If continuing to consume energy from a next zero gas supply chain is the right choice for particular gas customers, then this reduces the load – and hence the reliability and security of supply challenge – on a future net zero NEM.

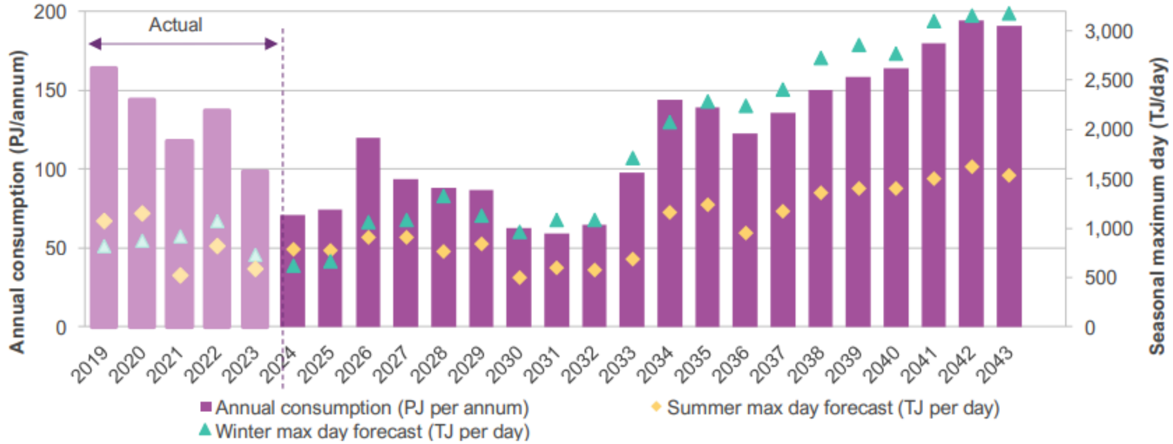
2.2.1 Policy to decarbonise gas supply

The same policy options proposed to decarbonise gas supply will enable a steadily decarbonising gas supply chain to take pressure off a net zero NEM. This demonstrates the value of Australian maintaining parallel and complimentary renewable electricity and renewable gas supply chains in a net zero future. With both supply chains able to firm supply and optimise demand of the other, Australian energy consumers can be the recipients of an optimised net zero energy system able to cater to each consumers unique energy needs.

3 APGA Responses to consultation questions

Consultation question	APGA response
Mobilising investment to transform energy 1. What actions are needed to attract the required large scale private capital and household investment in the energy transformation, with or without government intervention?	Market-based method for Scope 1 emissions of gas combustion accounting under NGER A market-based method is a key immediate action the Australian Government could take to mobilise investment in support of the transition. This would create a commercial proposition for the development of alternative low carbon fuels. • The CCA recommended this action in its 2023 NGER Review report[39]. • A market-based emissions accounting method is needed to create the commercial proposition for purchasing alternative low carbon fuels such as renewable gases. ○ NGER permits recognition of renewable gases in infrastructure, but only where there is a direct connection between a single producer and single customer. • If customers cannot reduce emissions by purchasing renewable gas, then there is no commercial proposition to purchase renewable gas at above natural gas prices. • Without a market-based method, procuring renewable gas supplied via common user infrastructure does not reduce a gas customer's accounted emissions under NGER. • Common user gas infrastructure is the cheapest way to transport and firm wholesale volumes of renewable gas due to low infrastructure cost and economies of scale[40]. • Without a market-based method, state-based renewable gas targets such as the NSW Renewable Fuels Scheme will result in gas customers being levied to subsidise the decarbonisation of others[41]. This is worse for NSW Safeguard Mechanism Facilities which would need to pay for decarbonisation under both the Safeguard Mechanism and the Renewable Fuels Scheme. A market-based method would resolve these conflicts.

[39] Climate Change Authority, 2023, *2023 Review of the National Greenhouse and Energy Reporting Legislation*.
[40] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.
[41] APGA, 2024, *Submission: Renewable Fuels Scheme Rule 1*, https://apga.org.au/submissions/renewable-fuels-scheme-rule-1-consultation; APGA, 2023, *Submission: NSW Renewable Fuels Scheme Expansion*, https://apga.org.au/submissions/nsw-renewable-fuels-scheme-expansion; APGA, 2023, *Submission: NSW Renewable Fuels Scheme*, https://apga.org.au/submissions/nsw-renewable-fuels-scheme

Consultation question	APGA response
	• A market-based method needs a viable certificate scheme – Renewable Gas Certificates being issued today under the GreenPower Renewable Gas Guarantee of Origin program could be used in market-based method design. • Note that current Guarantee of Origin (GO) certificate accounting design makes it impossible to use when supplying hydrogen via existing gas infrastructure[42].
Enabling electrification for a smooth transition 2. What actions are required to ensure Australia's energy systems can enable increased electrification, while maintaining equity, reliability and security?	<u>Enable 82% renewable energy target through Gas Power Generation (GPG)</u> • It is widely recognised that GPG can provide a firming role in an 82% renewable NEM, including AEMO analysis which shows by the 2040s, to supply winter peak demand the NEM will need 4.4x the GPG capacity required during 2023 [43]. **Figure 2 Actual and forecast NEM and Northern Territory gas generation annual consumption (PJ per year [PJ/y]) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2019-43**  Note: Northern Territory GPG consumption is included from 2020 onwards in this chart and any other charts related to GPG in this document.

[42] APGA, 2023, *Submission: Guarantee of Origin Scheme Accounting*; APGA, 2023, *Submission: Guarantee of Origin Scheme Design*; APGA, 2023, *Submission: Australia's Guarantee of Origin Scheme*
[43] AEMO, 2024, *2024 Gas Statement of Opportunities*

Consultation question	APGA response
	• The exclusion of GPG in the Capacity Investment Scheme reduces the incentive for investment in existing or new GPG. • This puts at risk the investment in GPG capacity identified by AEMO as being required to firm the NEM from the mid 2030s onward. • To maintain reliability and security of supply in the NEM, policy support is required to maintain investment in GPG. <u>Maintain grid reliability and security by optimising between powerlines and pipelines</u> • Australian and international analysis concludes that energy transport and storage by pipeline, including hydrogen pipeline, costs less than energy transport by powerline and energy storage via battery energy storage or pumped hydro44. • Gas infrastructure underpins the flexible operation of GPG today, enabling GPG to provide its firming capacity role. Renewable gas infrastructure has the opportunity to provide the same role. • Pipelines also have higher reliability, lower bushfire risk and greater social licence related to electricity transmission powerlines. <u>Maintain equity, reliability and security by enabling customers to choose lower cost options</u> • One of the challenges of maintain equity, reliability and security as Australia electrifies is the scale of the task at hand – more customers electrifying means more money needing to be spent on renewable generation, electricity transmission, electricity storage, and in turn, grid reliability and security mechanisms. • The lowest cost decarbonisation option for some energy customers will be an alternative low emission fuel such as renewable gas or renewable liquid fuel.

[44] Oxford Institute for Energy Studies, 2023, *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/11/ET27-Hydrogen-pipelines-vs.-HVDC-lines_HG_AP_2.pdf; GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.

Consultation question	APGA response
	• Creating policy to ensure customers which can decarbonise for lower cost are able to choose their lowest cost option will avoid unnecessary load being placed on the electricity system as it experiences the growing pains of the coming decades. • Customers being able to choose their lowest cost decarbonisation option also supports equity throughout the transition.

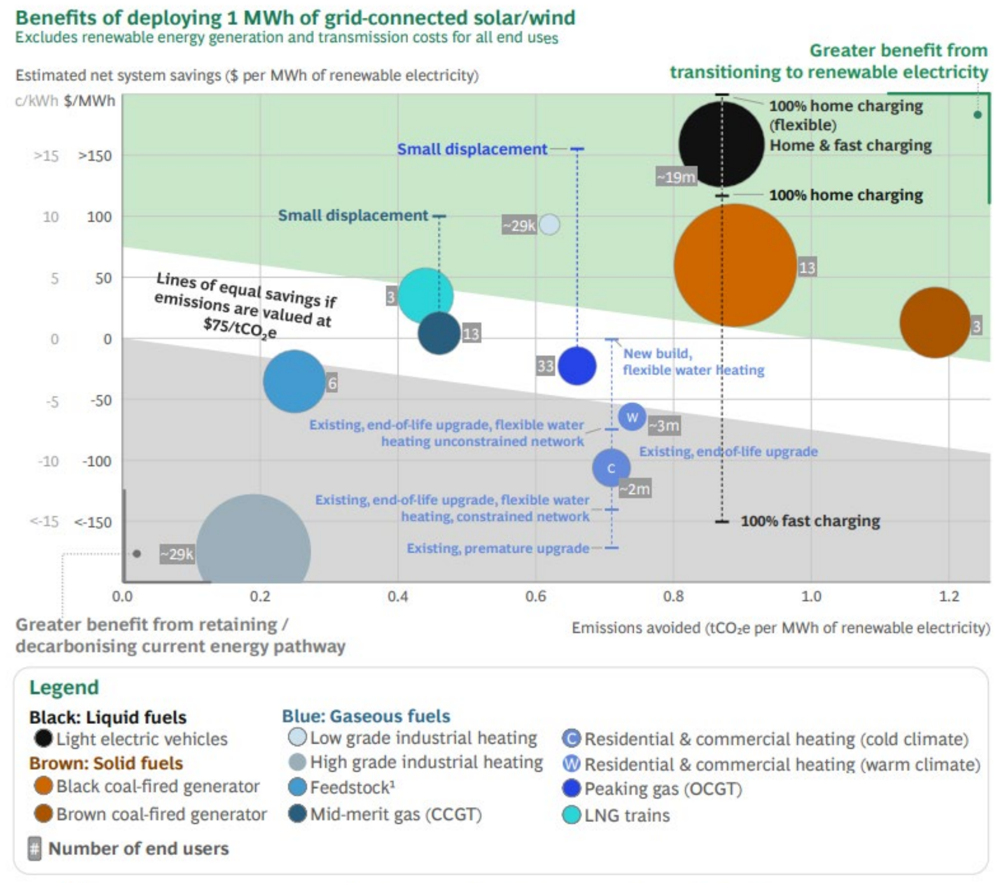
3. What insights do you have on the pace, scale and location of electrification, and how to embed this in system planning?

4. How can electrification efforts be sequenced to align with expansion of electricity generation and network capacity?

<u>Analysis by Boston Consulting Group (BCG) considers staging of electrification[45]:</u>

- BCG analysis considered the benefits of deploying each MWh of grid-connected solar/wind:

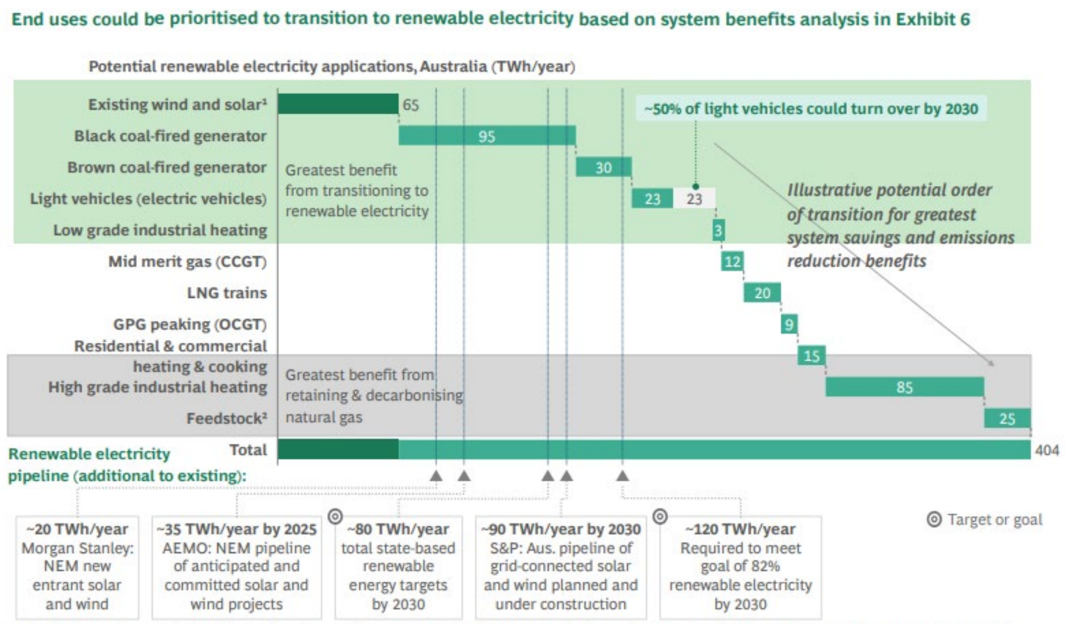
Exhibit 6: Grid-connected renewable electricity will have the greatest impact if first used to displace coal generation and liquid fuels



Note: Bubble size represents total annual volume of renewable electricity required to meet demand

- This analysis was then used by BCG to consider end uses which could be prioritised to transition to renewable electricity based on system benefits analysis:

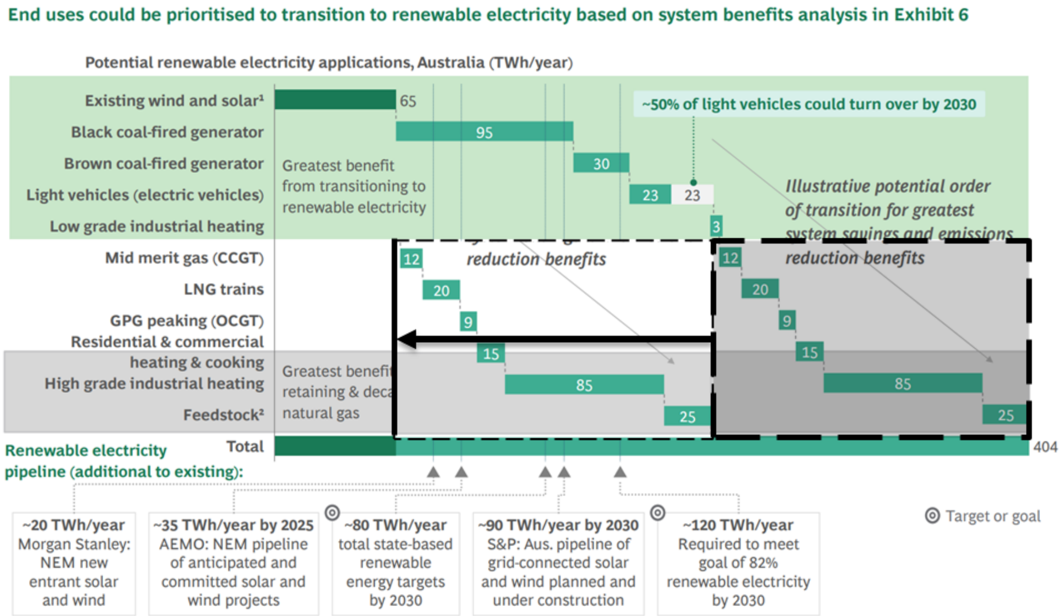
Exhibit 7: In the transition, natural gas can serve critical end uses that are hard and expensive to electrify



1. Includes onshore wind, utility scale solar, rooftop solar 2. Methane gas substituted with green hydrogen from grid-connected electricity
Source: Morgan Stanley Research, NEM new entrant plant estimate; AEMO, NEM Generation Information (Feb 2023); S&P Capital IQ, World Electric Power Plants Data Base; DCCEEW, Annual Climate Change Statement 2022; BCG analysis

- The energy end uses in the white and grey sections are energy uses which could be decarbonised for equal or lesser cost through renewable gas or liquid fuel uptake.
- This indicates that the energy transition can be accelerated for equal or lesser cost by enabling alternative low carbon fuels such as renewable gas and biomethane.

Exhibit 7: In the transition, natural gas can serve critical end uses that are hard and expensive to electrify



1. Includes onshore wind, utility scale solar, rooftop solar 2. Methane gas substituted with green hydrogen from grid-connected electricity
Source: Morgan Stanley Research, NEM new entrant plant estimate; AEMO, NEM Generation Information (Feb 2023); S&P Capital IQ, World Electric Power Plants Data Base; DCCEEW, Annual Climate Change Statement 2022; BCG analysis

Consultation question	APGA response
Growing alternative low carbon fuels 3. What policy settings and certainty are required to support a fair, equitable and orderly transition for the decarbonisation of both natural gas and liquid fuels?	<u>An NGER Market-Based Method for gas emissions accounting supports decarbonisation certainty and an orderly transition</u> • Renewable gases cost more than natural gas, but for many current gas customers renewable gases will be the only or the least cost decarbonisation option . • A market-based method is required for gas customers to have the emissions reduction from procuring renewable gas recognised in NGER accounting. • Members of APGA and Bioenergy Australia indicate there are tens of petajoules per annum of identified renewable gas projects which are awaiting a commercial basis upon which to reach FID. • A market-based method creates this basis by connecting emissions reduction to renewable gas procurement. <u>A Renewable Gas Target (RGT) creates certainty and supports a fair and equitable transition</u> • An RGT demonstrates to industry and the Australian public that the Australian government is committed to decarbonising gas supply. • This certainty will reduce investment risk for renewable gas production, allowing for more renewable gas projects to reach FID. • An RGT also provides a purpose for government initiatives in support of renewable gas to target – a government funding aimed at achieving a target is more politically justifiable than a government funding alone. • ACIL Allen analysis indicates that an RGT of 3% by 2030 and 9% by 2035 is sufficient to develop a renewable gas industry in time to achieve net zero gas supply by 2050. <u>Federal renewable gas Contracts for Difference (CfD) supports a fair and equitable transition</u> • A challenge of enabling renewable gases is that they are simultaneously more expensive than natural gas and can be a gas customer’s only or least cost decarbonisation option.

Consultation question	APGA response
	• Government support in the form of CfD schemes can target CfD values based on ensuring that renewable gases are sold at the same price as natural gas. • Tying government support to a guarantee of no increase in energy prices addresses cost-of-living impact risks while the scheme is in place • A CfD scheme sufficient tied to natural gas price targeting a 3% RGT by 2030 would ensure no cost of living impacts while enabling renewable gas production to develop.

4. What actions are required to establish low carbon fuel industries in Australia, including enabling supply and demand, and what are the most prospective production pathways?	<u>See answers to Questions 1 and 3 above considering policy required to establish renewable gas low carbon fuel industries in Australia.</u>
	
	<u>Biomethane and hydrogen are the most prospective renewable gas production pathways</u>
	
	• ACIL Allen analysis shows that a combination of hydrogen and biomethane are used alongside electrification to decarbonise gas use at least cost.
	    ○ Biomethane represents low hanging fruit being more economically viable than hydrogen in the immediate term, while hydrogen plays a large role in the long term.
	    ○ If hydrogen or biomethane constraints occur, modelling shows that the alternative renewable gas is the next best alternative. This is shown in modelling by constraining hydrogen or biomethane supply.
	• The low cost of energy transport and storage via hydrogen pipeline makes electrolysis collocated with renewable energy supply the most prospective hydrogen production pathway[46].
	    ○ Transporting desalinated water to hydrogen production locations represents negligible increase in hydrogen cost[47].

[46] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context*.
[47] Nous Group, 2023, *Net Zero Australia Final Modelling Results*, https://www.netzeroaustralia.net.au/wp-content/uploads/2023/04/Net-Zero-Australia-final-results-launch-event-presentation-19-April-23.pdf

Consultation question	APGA response

5. Are the proposed policy focus areas for managing the liquid fuels transition (outlined in Section 4 of the discussion paper) the correct areas to focus on, and what is missing?	<u>Proposed policy focus areas for managing the liquid fuels transition are equally applicable to managing the gas transition</u>
	• As identified by the EEPS Discussion Paper, Australia needs decarbonised gas supply to achieve net zero as some gas customer have no other decarbonisation alternative.
	• This need sits alongside the need to firm the NEM via GPG and the opportunity for hydrogen to be used in transport decarbonisation.
	• The table below maps these policy focus areas to the gas supply chain including policy actions proposed by APGA to deliver upon each area.
	• In some regards, the decarbonisation of gas supply is ahead of liquid fuels.
	    ○ Amendments passed in 2023 extended the National Gas Law (NGL) to renewable gases, extending recent supply security and reliability reforms to renewable gas supply. This ensures that gas security and reliability is maintained and supply chain vulnerabilities are managed.
	    ○ The recently published National Energy Performance Strategy (NEPS) considers gas appliance efficiency which will support reducing fossil-based gas demand.
	• The remaining policy focus area, decarbonising Australia's gas supply mix, can be supported by the policy options identified under Question 5 above.

Consultation question	APGA response

Policy focus areas	1. Decarbonise our gaseous fuel mix	2. Reduce fossil-based gas demand	3. Ensure gas security and reliability	4. Manage supply chain vulnerabilities
Reason:	Driving renewable gases supports decarbonisation efforts and de-risks gas supply through diversification	Improving energy efficiency and promoting behavioural change reduces emissions and gas demand	Leveraging existing gas security and reliability of supply legislation will ensure climate and energy objectives are met through the transition	Existing mechanisms to address gas supply chain disruptions ensures government and industry can quickly respond to emerging gas supply chain risks
Renewable Gas Policy Action:	- NGER recognition of renewable gas certificates - Setting a national Renewable gas target in the FGS - Federal contracts for difference for renewable gas supply	- Increase gas appliance efficiency floor via existing NEPS process [UNDERWAY[48]]	- Expand existing gas security and reliability of supply legislation to cover renewable gases [COMPLETED[49,50]]	- Expand existing mechanisms to address gas supply chain disruptions to renewable gases [COMPLETED[49,51]]

<u>Policy options to ensure the decarbonisation of gas in Australia is fair, equitable and orderly.</u>

- An NGER Market-Based Mechanism ensures fairness by enabling gas customers the ability to account for emissions reduction in line with the renewable gas paid for.

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[48] DCCEEW, 2024, *National Energy Performance Strategy*.
[49] DCCEEW, 2023, *Extending the national gas regulatory framework to hydrogen and renewable gases*.
[50] AEMO, 2023, *East Coast Gas Reforms*.
[51] Including through the National Gas Emergency Response Advisory Committee; see AEMO, 2024, *National role*, https://www.aemo.com.au/energy-systems/gas/emergency-management/national-role

Consultation question	APGA response

	• This includes instances where gas customers are required to pay for renewable gas certificates under legislation such as under the NSW Renewable Fuels Scheme and proposed Victorian and Western Australian renewable gas targets.
	• A national RGT promotes a fair, equitable and orderly transition.
	    ○ Fair and equitable transition is enabled by an RGT as it would still allow customers to choose to electrify if this is the best option for the customer. No customer is forced to decarbonise via renewable gas if it is not the best option for their individual circumstances. Less gas customers results in RGT percentages being met more easily by reducing total gas demand.
	    ○ An RGT promotes an orderly transition by bringing a moderate yet practical portion of renewable gas production forward, ensuring sufficient supply is available in time to be available for customers which required it. This also ensures that cost reducing lessons are learned earlier in the transition.
	• Government CfDs promote an equitable transition where they are used to keep renewable gas prices low, avoiding cost of living impacts.

Building Australia's clean energy workforce 6. What actions are required to ensure workforce requirements for the energy transformation are met, while supporting equitable outcomes?	<u>Australia's natural gas workforce is ready to deliver renewable gas today</u> • The Australian gas industry boasts a robust skilled workforce skilled in ensuring Australia's gas industry is one of the safest and most successful globally. • The skills to operate natural gas infrastructure are the skills required to operate renewable gas infrastructure. • The rapid development of the Queensland LNG industry demonstrates its ability to mobilise rapidly to deliver upon investment in gas production, transmission and export infrastructure. • Continued lack of government support for renewable gases risks leading to a brain drain on the gas industry – government support of renewable gases should influence more skilled workers staying and moving into the gas industry.

Consultation question	APGA response
Maximising outcomes for people and businesses 7. What actions are required to ensure better energy outcomes for people and businesses, and maximise their benefit from the energy transformation? 8. What social licence and circular economy aspects should be considered as part of the pathway for the energy transformation?	Hydrogen pipelines can derisk energy infrastructure social licence • Not only are gas, biomethane and hydrogen pipelines lower cost than HVAC and HVDC powerlines, but pipelines are inherently underground infrastructure[52]. • This means that there are less visual and practical impacts on landholders once pipelines are installed. • Third party impact and bushfire risks are also lower with buried pipelines compared to aboveground powerlines.
Other 9. What are other gaps in Australia's energy sector decarbonisation policy and what actions are required to address them?	Robust multi- sector energy modelling • ACIL Allen analysis demonstrates the value of modelling the opportunity for multiple energy vectors to decarbonise energy customers. • Modelling robustness including consideration of energy and appliance cost as well as cost ranges can uncover a wider range of cost-effective decarbonisation options. • Without analysis like this, Australia risks making the wrong renewable energy investment decisions, delaying the transition. • APGA recommends that the least cost decarbonisation pathway be modelled each sector of customers considering all physically possible renewable energy alternatives. • APGA understands that the CSIRO is proposing a Smart Energy Mission to pursue multi-sector modelling and recommends that this be prioritised by government.

[52] GPA Engineering, 2022, *Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context* available at https://www.apga.org.au/sites/default/files/uploaded-content/field_f_content_file/pipelines_vs_powerlines_-_a_technoeconomic_analysis_in_the_australian_context.pdf

Attachment 1: Renewable Gas Target – Delivering lower cost decarbonisation for gas customers and the Australian economy by ACIL Allen

13 December 2023

Submission: Agriculture and Land Sectoral Decarbonisation Plan

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure, connecting natural and renewable gas production to demand centres in cities and other locations across Australia. Offering a wide range of services to gas users, retailers and producers, APGA members ensure the safe and reliable delivery of 28 per cent of the end-use energy consumed in Australia and are at the forefront of Australia's renewable gas industry, helping achieve net-zero as quickly and affordably as possible.

APGA welcomes the opportunity to contribute the Department of Agriculture, Fisheries and Forestry consultation on the first sectoral decarbonisation plan, the Agriculture and Land Sectoral Plan. Australia has the opportunity to reach our national net zero target when all industry sectors work together towards this common goal. However, there is risk of misalignment on electricity and energy decarbonisation between individual sectoral plans.

APGA supports a net zero emission future for Australia by 2050,[1] Renewable gases represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. As set out in Gas Vision 2050,[2] APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC,[3] which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy to homes, businesses, and industry throughout Australia.

Risk of sectoral plan misalignment

The sectoral decarbonisation plans provide the opportunity to develop coordinated decarbonisation strategies for specific industries. In drafting these documents, the relevant departments should aim to address only the issues directly relevant to that industry sector, and in particular leave issues on decarbonising energy and electricity to that sectoral plan.

The consumption of electricity and energy can be decarbonised in two ways:

1. Changing the type of energy being used to a decarbonised or decarbonising type of energy – for example, electrifying diesel demand; or
2. Decarbonising the type of energy already being used – for example, using drop in renewable diesel.

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[1] APGA, *Climate Statement*, available at: https://www.apga.org.au/apga-climate-statement
[2] APGA, 2020, *Gas Vision 2050*, https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[3] Future Fuels CRC: https://www.futurefuelscrc.com/

The five sectoral plans which sit alongside the Electricity and Energy Sectoral Plan risk making uninformed decisions if they make electricity and energy decarbonisation decisions without the context of the Electricity and Energy Sectoral Plan.

Importantly, the Electricity and Energy Sectoral Plan has the opportunity to set all four energy supply chains – solid, liquid, gaseous and electric – on their own decarbonisation journeys. Understanding each of these energy decarbonisation pathways will be key to each other sectoral plan determining the most economically efficient approach to decarbonising their electricity and energy use.

In discussion with DAFF to date, the Agriculture and Land Sectoral Plan appropriately ringfences these issues by only addressing energy and fuel as it pertains to on-farm use. This leaves the conversation of whether existing fuel supply chains could be decarbonised, as well as whether there are multiple alternatives, to the Electricity and Energy sectoral plan. APGA recommends that this model be carried forward for the development of other sectoral plans, and that each plan loops back upon delivery of the Electricity and Energy plan to reconsider its approach to electricity and energy.

Renewable gases can contribute to decarbonisation

The agriculture sector has a unique opportunity to both decarbonise its own sector and provide the necessary feedstock to contribute to the decarbonisation of other sectors. APGA's interest in the Agriculture and Land Sectoral Plan focuses on two areas: increasing feedstocks for use creating biomethane and other renewable biogenic fuels, and on decarbonising on-farm machinery and practices using renewable gases. These areas will be addressed in the following section.

Opportunities for the agriculture sector to decarbonise using renewable gases

The consultation paper acknowledges some of the opportunities available to the agriculture sector to decarbonise using renewable gases.

Decarbonising farming practices

The production of ammonia for use in fertiliser (and other uses) is currently very energy intensive, and is a considerable source of global carbon emissions. Fertilisers produced using renewable gases, rather than fossil gases, offer immediate opportunities to decarbonise farming practices.

Major ammonia producers Incitec Pivot[4] and Yara[5] are transitioning to ammonia production from green hydrogen in Australia. There are also smaller scale, on-farm projects such as the Good Earth Green Hydrogen and Ammonia project[6] on the Keytah cotton station which will support the decarbonisation of the entire property. The project will produce ammonia for use at Keytah and green hydrogen to replace diesel used in regional transport.

[4] Incitec Pivot, 2023, *Green ammonia at Gibson Island*, https://www.incitecpivot.com.au/sustainability/projects/green-ammonia-at-gibson-island
[5] Engie, 2023, *Yuri Renewable Hydrogen to Ammonia Project*, https://engie.com.au/yuri
[6] ARENA, 2023, *Good Earth Green Hydrogen and Ammonia Project*, https://research.csiro.au/hyresource/good-earth-green-hydrogen-and-ammonia-project/

Decarbonising on-farm fuel use
Heavy vehicles and farm machinery are also large contributors to agricultural emissions. Currently, electrification is seen as the major avenue for decarbonising their energy use. Renewable gases should also be supported as a decarbonisation option which is not reliant on potentially challenging electricity or battery infrastructure.

Farm vehicles powered by green hydrogen fuel cells[7,8] and dual fuel technologies[9] are being brought to market and will soon be available in Australia. Biomethane produced from agricultural and other feedstock can also be compressed into a renewable version of CNG, which already powers millions of passenger vehicles worldwide and can be adapted for heavy vehicles and machinery.

Accessing renewable gas supply chains
Both biomethane and green hydrogen supply chains will be readily available for the agriculture industry, provided the right policy settings are in place. As biomethane is chemically indistinguishable from natural gas, existing gas transmission and distribution pipelines can provide access without any changes to the physical infrastructure.

Regional communities will be able to access hydrogen through local generation projects, such as the Good Earth Green Hydrogen and Ammonia projects, or from hydrogen pipelines. Generating renewable electricity, converting it to hydrogen and transporting it in pipelines is a process that may be cost competitive, and certainly much easier, than transporting this energy in transmission powerlines. Gas transmission pipelines are safer, more reliable, and with fewer environmental impacts than transmission powerlines, with fewer impacts on landholders. Ready access to these pipelines will provide opportunities for regional communities to decarbonise which may not be available through transmission powerlines.

Opportunities for the agriculture sector to contribute to broader decarbonisation
The agriculture sector has a unique opportunity both reduce its own emissions and contribute to broader decarbonisation in Australia through the production of biogenic fuels.

Biogenic fuels, including biomethane and bio-CNG, as well as biodiesel, are produced from organic matter and are carbon-neutral when used in place of fossil fuels. Bioenergy Australia's current assessment of biomethane potential in Australia is at least 350 PJ annually, which much of this from the agriculture sector.[10] This can be sourced both from direct production of feedstock, and also from organic agricultural waste. This provides a market for waste product and ultimately a circular economy for agricultural product.

[7] Seneca ESG, 2023, *Kubota to roll out hydrogen-powered fuel cell tractors in 2025*, https://senecaesg.com/insights/kubota-to-roll-out-hydrogen-powered-fuel-cell-tractors-in-2025/
[8] JCB, 2023, *JCB: Building a hydrogen future*, https://www.jcb.com/en-au/campaigns/hydrogen
[9] Blue Fuel Solutions, 2023, *H_2 Dual Power*, https://h2dualpower.com/en
[10] ENEA Consulting, 2021, *Australia's Bioenergy Roadmap*, https://arena.gov.au/assets/2021/11/australia-bioenergy-roadmap-report.pdf

How this sectoral plan can support decarbonisation

Recommend support for renewable gas supply chains

APGA recommends that the Agricultural and Land Sectoral Plan not make recommendations about electricity and energy, until the recommendations of the Electricity and Energy Sectoral Plan are outlined.

The Agriculture and Land Sectoral Plan should recommend emplacing frameworks for developing renewable gas (specifically biomethane) supply chains. Ideally, this would support a renewable gas target or other mechanism which promotes gas use decarbonisation within the Electricity and Energy Sectoral Plan.

Green hydrogen[11] and biomethane[12] projects are already underway and actively decarbonising gas networks in Australia, supported by state and federal funding. But there are challenges to broader rollout of these technologies, some of which are specific to the agricultural sector. There is currently no widespread deployment of renewable gas, or national plan to achieve this. Ongoing, coordinated, nationally-led policy support for both the supply and demand side is required to provide the necessary signals for investment in the industry.

Whole-of-farm accounting

APGA recommends that the Sectoral Plan consider available carbon accounting methods for agriculture under the Emissions Reduction Fund and whether new or combined methods would be fit for purpose.

Emissions accounting for the agricultural sector is currently piecemeal and not streamlined. This was acknowledged in the *Report of the Expert Panel examining additional sources of low cost abatement*[13] (King Review) as a key limitation to optimising carbon abatement in the agricultural and other sectors. Following the King Review, the Federal Government appointed an independent panel to review the integrity of Australian Carbon Credit Units (ACCUs) under Australia's carbon crediting framework.

Recommendation 5 of the ACCU Review[14] proposes establishing a proponent-led method development pathway. Implementing this recommendation would allow for the development of a method that brings together and expands existing carbon accounting methods under a single "whole-of-farm-accounting" method. The Carbon Market Institute has proposed a

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[11] AGIG, 2023, *Hydrogen Park South Australia*, https://www.agig.com.au/hydrogen-park-south-australia

[12] Jemena, 2023, *Malabar Biomethane Injection Plant*, https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/

[13] Department of Industry, Science, Energy and Resources, 2020, *Report of the Expert Panel examining additional sources of low cost abatement*, https://www.dcceew.gov.au/sites/default/files/documents/expert-panel-report-examining-additional-sources-of-low-cost-abatement.pdf

[14] Department of Climate Change, Energy, the Environment and Water, 2022, Independent Review of Australian Carbon Credit Units Final Report, https://www.dcceew.gov.au/sites/default/files/documents/independent-review-accu-final-report.pdf

model for this, the Active Land Management & Agricultural Production (AL-MAP) method.[15] This method would combine multiple carbon sequestration or emission avoidant land management activities from vegetation and soil which sequester carbon or avoid emissions, under a single method.

The agriculture sector can also be supported through developing a method to recognise natural gas displacement by a wider range of zero emissions gases. Currently this is constrained to biomethane from a narrow range of feedstocks.

To discuss any of the above feedback further, please contact me on +61 422 057 856 or jmccollum@apga.org.au.

Yours sincerely,

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Australian Pipelines and Gas Association

[15] Carbon Market Institute, 2021, *Blueprint for holistic approach to carbon farming – Active Land Management & Agricultural Production (AL-MAP) Method*, https://carbonmarketinstitute.org/app/uploads/2021/08/AL-MAP-Method-Blueprint_final.pdf