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Ms Anna Collyer
Chair
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000

Submitted electronically via the AEMC Rule change portal

RULE CHANGE REQUESTS: GAS DISTRIBUTION NETWORKS.

Dear Ms ~~Collyer~~ Anna

Energy Consumers Australia (ECA) is pleased to submit four rule change proposals which aim to update the National Gas Rules (NGR) and ensure they remain fit-for-purpose in a transitioning energy system.

The current NGR are no longer adequately promoting the long-term interests of consumers in the context of increased household and small business electrification and a gas distribution network in decline. This document outlines four urgent amendments we believe are necessary for the NGR to continue to meet the National Gas Objective (NGO).

As consumers take up the opportunities electrification presents, they leave behind a network of gas distribution pipelines worth a combined $11 billion.[1] However, the reality of gas network decline is not currently reflected in the NGR, which were created with the expectation of ongoing growth of the network.

This suite of rule changes will require gas distribution networks to proactively plan for the future of their networks and make decisions which will minimise any further non-critical investment. They also aim to increase the tools and information regulators, councils, governments, electricity distribution networks, advocates and other stakeholders have available to them to start actively planning for how we can fairly transition away from gas.

Failing to proactively and effectively address the decline of the network poses significant risk to consumers. Our Stepping Up report found that network prices on household gas bills would more than quadruple – from $280 per year today to $1,170 in 2050.[2] This is because, as consumers leave the gas network, the costs of maintaining and operating the network will be shared by an ever-decreasing pool of consumers, many or perhaps most of whom will be in profoundly vulnerable circumstances and least able to electrify.

Our report with Dynamic Analysis found that limiting any further spending on gas networks must be a priority for reducing the risks associated with stranded assets.[3] We are confident that these four proposed changes to the NGR are necessary to ensure any future spending is prudent and that consumer interests are being prosecuted in gas network planning arrangements.

The enclosed rule change proposal includes relevant detail and argument on the four rule change requests along with suggested drafting – as an appendix – for one (that is, requiring new consumers to pay the upfront costs of connecting to the network).

Throughout the development of these rule change proposals we have engaged with a range of stakeholders, including the AEMC, AEMO, AER, Commonwealth and jurisdictional departments, Energy Networks Australia, the Australian Energy Council, and other consumer advocates.

We sincerely thank members of your team who provided critical and constructive feedback on early drafts of the rule change requests. We also thank Kieran Donoghue from Newgrange Consulting and the Justice and Equity Centre, who provided essential support in the development of the enclosed proposals.

These rule changes are crucial to ensure that consumer interests are adequately protected in the transition from gas. We look forward to engaging with the Commission and other stakeholders throughout the rule change process. Please contact me should you wish to discuss further.

Yours sincerely

Brendan French

Brendan French
Chief Executive Officer

ENERGY CONSUMERS AUSTRALIA

Gas Distribution Network Rule Change Requests

DATE: 14/02/2025

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1 Rule Change Proponent Details

Brendan French
Chief Executive Officer
Energy Consumers Australia

2 Executive Summary

Net zero targets and the economic benefits of electrification for households have profound implications for gas distribution networks and create risks for gas consumers. Australian residential and commercial gas use is expected to decline 72% by 2043[1] and to be largely non-existent by 2050[2] as households and businesses electrify and leave the gas network.

The Commonwealth Government's Future Gas Strategy says "households and small businesses will have, for the most part, electrified by 2050"[3] as:

> *"Most households are likely to embrace opportunities to reduce their energy bills and emissions by switching from gas to electric appliances when existing appliances need replacing."*[4]

The Commonwealth has also provided funding to support this transition.[5]

Multiple analyses indicate that electric cooking, heating and hot water is cheaper across a wide range of household customers. In many cases, this holds even after accounting for appliance conversion costs; the cost advantage is even higher for new homes.

If households and small businesses take advantage of government incentives and realize the benefits of electrification, there are multiple impacts to gas distribution networks. As large numbers of users leave, many of their assets will become stranded – unused before their economic life ends. Furthermore, because households pay more than 90% of gas distribution network revenue, these networks may lack the funding necessary to pay for on-going operations.[6]

The impacts on gas consumers are just as significant. In a 2023 report for Energy Consumers Australia, CSIRO undertook modelling to determine the impacts to household energy bills under the Integrated System Plan's 'step change' or central planning scenario. The modelling showed that network prices on household gas bills would more than quadruple – from roughly $280/year today to $1,170 in 2050.[7] Overseas industry observers have noted that the price impacts could be even more severe. Ofgem, the British energy regulator, states that "network charges could rise by a factor of 10 within 20 years."[8]

The Commonwealth's *Future Gas Strategy* notes these issues and potential repercussions: "The rising cost of remaining on the reticulated gas network can provide the economic incentive to transition for those

[1] AEMO, 2024 Gas Statement of Opportunities (GSOO), Step Change Scenario accessed via gas forecasting data portal.
[2] Reedman, et. al., Multi-sector energy modelling 2022: Methodology and results: Final report, CSIRO Report No. EP2022-5553, Australia. P. 59
[3] Australian Government Department of Industry, Science and Resources, Future Gas Strategy, 2024. p. 38
[4] Australian Government Department of Industry, Science and Resources, Future Gas Strategy, 2024. p. 42
[5] For example via the Household Energy Upgrades Fund
[6] AER, 2022 Gas Network Performance Report, Figure 7-9.
[7] Graham, P., et. al., 2023, Consumer impacts of the energy transition: modelling report, CSIRO, Newcastle.
[8] Jan Rosenow, et. al. 2024 "The elephant in the room: How do we regulate gas transportation infrastructure as gas demand declines?, One Earth, Volume 7, Issue 7, pp. 1158-1161

able to control – and afford – the cost of switching. However, renters, those in community and social housing, and low-income households, have limited or no control over whether they electrify, even where they might want to transition."[9] Many if not all of these consumers are likely to be left using the gas network into the future.

Some are holding out for the possibility of widespread conversion of gas distribution networks to carry green hydrogen or biomethane. There are barriers to this happening at scale for low pressure networks: green hydrogen would be significantly more expensive than electrification while also requiring appliance conversion and multiple logistical challenges.[10;11] The total annual production potential for biomethane in Australia is 371 PJ – only 25% of annual domestic gas use.[12] Outside of residential and commercial users, the existing gas demand that must be decarbonised to meet 2050 net zero targets is 3 times larger than biomethane potential.[13] The feedstocks for biomethane are limited, and there are expected to be higher value uses for the scarce and expensive feedstock (e.g. aviation fuel, hard-to-abate industrial uses, gas powered generation) than household and small business use.

Even if some parts of the low-pressure gas network are still used by hard-to-electrify customers beyond net zero target dates, there is an overwhelming likelihood that large parts of the network will no longer be used. Recently, AusNet Gas Services stated the conclusion concisely in its application to the Australian Energy Regulator (AER) to reopen its access arrangement: "long term [gas] network decline is now inevitable".[14]

Despite this obvious and growing risk, current and recent regulatory processes have seen gas distribution networks continue to seek large capital expenditure (capex) allowances. In two cases (Multinet in Victoria and ATCO in Western Australia), allowed capex exceeds that of the previous period. Simultaneously, gas distribution networks have also sought accelerated depreciation allowances, protecting their investors against stranded asset risk by recovering revenue at a faster rate from customers. Gas distribution networks have also sought to introduce high abolishment fees ($800-$1,500), which serve to disincentivise customers from disconnecting from the network. In addition, the likelihood of future abolishment costs does not appear to be factored into relevant capex assessments, such as connections and replacement (repex).

This inconsistent approach to stranded asset risk is not in the long-term interest of consumers, who are losing all ways: being exposed to future stranded asset risk while paying for accelerated depreciation on existing assets. While the relevant regulators – the Australian Energy Regulator (AER) and the Economic Regulation Authority (ERA) of WA – have used their powers under the Rules to reduce capex claims, we are concerned that this does not result in a significant enough reduction in expenditure when the full context is considered.

Gas distribution networks have fewer information provision requirements compared to electricity networks.[15] While the electricity system has widespread planning requirements – the Integrated System Plan, Distribution Annual Planning Reports, and Regulatory Investment Tests for new investments – there

[9] Australian Government Department of Industry, Science and Resources, Future Gas Strategy, 2024. p. 41
[10] Rosenow, J. 2024, A meta-review of 54 studies on hydrogen heating. Cell Reports Sustainability
[11] Rosenow, J. 2022, Is heating homes with hydrogen all but a pipe dream? An evidence review.
[12] ECA analysis of DISR Future Gas Strategy Analytical Report and ARENA, Australia's Bioenergy Roadmap Appendix – Resource Availability, November 2021
[13] ECA analysis of DISR Future Gas Strategy Analytical Report and ARENA, Australia's Bioenergy Roadmap Appendix – Resource Availability, November 2021
[14] AusNet, Reopener cover letter, October 2024
[15] See Dynamic Analysis, Turning down the gas - Minimising consumer risk, September 2024 for an outline of the differences in data collected

is, in fact, no planning requirement on gas distribution networks. Despite facing a high degree of uncertainty, gas distribution networks have no requirement to develop and share plans for the expected future of their systems. Gas distribution networks do not share maps of their network indicating where many consumers still exist and where only few are left, nor do they make forward looking projections about where they anticipate disconnections to happen most quickly. They also fail to provide insights into gas pipelines that may require replacement beyond the five-year cycle of their existing access arrangement. Such information would be valuable to many stakeholders, including state, territory, and local governments and electricity distribution networks, who could use these insights to deliver a lower cost energy transition overall.

Regulatory change is urgently needed to reflect these growing risks and deficiencies in order to better meet the National Gas Objective (NGO).

Energy Consumers Australia has identified four key areas in which the National Gas Rules (NGR) should be amended to recognise and address these risks:

a. Amendment to the rules for new gas connections to require the connecting party to pay up front for their connection, to ensure other users of the gas network are not exposed to the risk of these connections becoming stranded assets.

b. New planning requirements for gas distribution networks, to ensure regulators, governments, electricity distribution networks and other stakeholders have the necessary information to better understand opportunities to minimise capital expenditure and overall energy system costs.

c. Amendment to the depreciation rules, to put stronger conditions around the ability of gas distribution networks to accelerate the depreciation of their regulated assets.

d. Amendment to the capital expenditure criteria rules, to ensure that declining use of the gas network is properly considered in evaluating whether a capital project is justifiable.

3 Applicability of rule change proposals

The focus of our rule change proposals is on gas distribution networks. Energy Consumers Australia represents household and small business energy consumers. In the context of reticulated gas, small users are connected to the low-pressure component of distribution networks. They outnumber large customers and pay the vast majority of distribution charges. Indeed, the best data available indicates that households alone pay more than 93% of the cost of the gas distribution network.[16]

While all gas distribution consumers indirectly pay transmission costs, they are a smaller part of the bill. Transmission costs are apportioned more broadly, including to some very large users connected directly to transmission pipelines. While gas transmission networks are not immune to the same issues that threaten distribution networks, they are a discrete topic that we have not explored in detail. Seventy percent of Australia's overall gas production is sent overseas, and it reaches port via transmission networks;[17] the impact on these facilities is not our focus or area of expertise. Other large consumers that connect directly to gas transmission networks use gas in ways that are less easily substitutable than gas consumed via the distribution network.

Two of the four rule change proposals – the accelerated depreciation and the capex proposals – are relevant only to scheme pipelines. Non-scheme pipelines are not price-regulated and do not have to seek regulatory approval to recover the costs of their capital expenditure. The other two proposals – the connections and planning proposals – are intended to apply to all distribution network pipelines.

[16] AER, 2022 Gas Network Performance Report, Figure 7-9.
[17] Geosciences Australia, Australia's Energy Commodity Resources 2024

4 Background

Australians have been aware of the need to reduce greenhouse gas emissions for several decades. Natural gas (methane) is a greenhouse gas with a global warming potential 28 times carbon-dioxide.[18] When combusted, it converts into carbon dioxide. Most of the gas that flows through their networks will be combusted (some is used as a feedstock for chemical processes) and thus contribute to climate change. Methane that leaks from gas pipelines contributes directly to climate change as well.

The more recent introduction of legislated net zero targets at both national and jurisdictional levels[19] has only crystallised the timeframes for decarbonisation rather than introduced it as a constraint. To facilitate achievement of these targets, Victoria[20] and ACT[21] have already introduced restrictions on gas network connections and incentives for gas users to switch to electric alternatives. In both cases, these policies are forecast to drive a significant reduction in reticulated gas use over the next decade. Four of the seven gas distribution networks subject to full regulation are in these jurisdictions (See Table 1).

Table 1: List of major gas distribution networks

Network	Jurisdiction	form of regulation	Jurisdictional policy	customers	km pipelines	RAB ($m)	regulatory period
Multinet	Vic	full	Gas Substitution Roadmap	719,436	10,143	1,300	1 Jul 2023 - 30 Jun 2028
Australian Gas Networks (Vic)	Vic	Scheme	Gas Substitution Roadmap	739,621	11,984	1,800	1 Jul 2023 - 30 Jun 2028
AusNet Services	Vic	Scheme	Gas Substitution Roadmap	778,752	12,337	1,800	1 Jul 2023 - 30 Jun 2028
Jemena Gas Networks	NSW	Scheme	n/a	1,476,686	25,481	3,400	1 Jul 2025 - 30 Jun 2030
Evoenergy	ACT/NSW	Scheme	Integrated Energy Plan	157,205	4,614	390	1 Jul 2022 - 30 Jun 2027
Australian Gas Networks (SA)	SA	Scheme	n/a	466,417	8,484	1,800	1 Jul 2022 - 30 Jun 2027

[18] Clean Energy Regulator, Global Warming Potential, updated March 2024
[19] AEMC, Targets statement for greenhouse gas emissions
[20] Victorian Government, Gas substitution Roadmap, 2022
[21] ACT Government, Canberra's electrification pathway

Mid-West and South-West Gas Distribution Systems (ATCO)	WA	Scheme	n/a	796,665	14,500	1,600	1 July 2025 – 30 June 2030
Allgas Energy	QLD	Non-scheme	n/a	100,000	3,218	n/a	N/a
AGN Queensland	QLD	Non-scheme	n/a	89,100	3,463	n/a	N/a
Tasmanian Gas Networks	TAS	Non-scheme	n/a	15,000	839	n/a	N/a

Source: AER, ERAWA, company websites

Given that jurisdictions without specific policies in place have net zero targets by 2050 at the latest we consider there are two realistic scenarios: either they will introduce relevant policies shortly, or they are confident that the economics of electric alternatives or customer sentiment will drive a switch away from gas by small customers. Other options include:

- that the gas system is decarbonised by other means, which is highly improbable as discussed further below; or
- that the net zero targets are missed or abandoned, which we do not consider an appropriate scenario to contemplate under the NGO.

In other words, it is reasonable to suppose that even in jurisdictions that have not at this time introduced policies aimed at reducing demand on the gas networks, that demand will fall in any case.

Indeed, this thesis is supported by relevant authorities and expert forecasters. According to the Australian Energy Market Operator (AEMO), residential and commercial gas use is expected to decline 72% by 2043[22]. In multiple studies, CSIRO, the national science agency, projects residential and commercial gas use to be largely non-existent by 2050 as households and businesses electrify and leave the gas network.[23;24]

The Climate Change Authority's recent Sector Pathways review asserts that "the long-term complete electrification of buildings is the optimal decarbonisation approach, and governments should develop strategies to efficiently and equitably realise this."[25] The Commonwealth Government's Future Gas Strategy says "households and small businesses will have, for the most part, electrified by 2050"[26]

The number of customers connecting to the gas network has slowed significantly in recent years.[27] An increasing number of property developers advertise themselves as building all-electric homes in response

[22] AEMO, 2024 Gas Statement of Opportunities (GSOO), Step Change Scenario accessed via gas forecasting data portal.
[23] Reedman, et. al., Multi-sector energy modelling 2022: Methodology and results: CSIRO Report No. EP2022-5553, Australia. P. 59
[24] Verikios, G. et. al, 2024, Modelling Sectoral Pathways to Net Zero Emissions, EP2024-4366, CSIRO, Australia.
[25] Climate Change Authority, Sector Pathways Review – Built Environment (2024), p. 13
[26] Australian Government Department of Industry, Science and Resources, Future Gas Strategy, 2024. p. 38
[27] Analysis of Essential Services Commission, Energy Market Dashboard and Australian Energy Regulator, Retail Energy Performance Updates - accessed July 2024

to climate and health concerns. AusNet, the largest Victorian gas network, recently stated that property developers active in their service area expect "around 85% of [new housing] lots…to be all-electric," even though many of these lots have planning permission to use gas.[28] Jemena, the largest gas distribution network in Australia, is forecasting customer numbers to decrease from 2028 due to slowing construction rates, changing building practices, and electrification trends.[29] Notably, they operate in NSW, where there is currently no state government policy prohibiting new gas connections.

There are clear financial benefits to consumers, particularly households, from electrifying. ECA's own analysis, incorporating detailed modelling by CSIRO, found that the average household in states covered by the National Electricity Market, would save by electrifying their gas use – and that these savings would grow over time. Their analysis found that the average household saved $290/year by electrifying their gas use in 2030, with benefits growing to $660/year and $810/year for households electrifying in 2040 and 2050, respectively. Households that have solar and therefore cheaper electricity would save more.[30]

The AEMC's own retail price projections support the thesis that electrification is in consumers' financial interests.[31] The Commission's most recent Price Trends report forecasts that "electrification (including transport) is projected to reduce average household energy costs by nearly $1,000 per year, or by almost 20% of current spending on energy."[32]

Multiple analyses over a decade have found similar results. It has been cost-effective for new homes to go all electric for several years, as can be seen from Table 2. Increasingly, retrofits of existing houses are cheaper across a wide range of household customers, even after accounting for appliance conversion costs. For example, in 2020 ACIL Allen modelling for the ACT determined that fuel switching was net present value positive for 10 of the 12 household archetypes modelled if the households did not have rooftop PV installed and 12/12 if they did have rooftop PV.[33]

The Grattan institute's 2023 analysis Flame out - the future of natural gas, found retrofits to be net present value positive across multiple jurisdictions and numbers of appliances, with only Perth homes with no gas heating returning a NPV negative outcome.[34]

Table 2: Selected analyses of costs and benefits of household electrification

Report	Author	Year	Retrofit/ New Build	Review process	Key takeouts
Household energy choice in the ACT – Modelling and analysis	ACIL Allen	2020	Retrofit	ACT	Many customer archetypes are financially better off, and all are if they have rooftop PV. Tariff structure changes could influence results
Saving money with efficient, all-electric homes	Renew	2022	new build	Inquiry into Renewable Energy in Victoria	New build cheaper for all-electric plus ongoing savings

[28] AusNet, Gas Access Arrangement Review 2024-28 Variation Proposal, September 2024, p. 8.
[29] Jemena, 2025 Draft Plan
[30] Graham, P. Consumer impacts of the energy transition: modelling report, CSIRO, Newcastle 2023.
[31] AEMC, Price Trends 2024 Final Report, November
[32] Ibid., p18
[33] ACIL Allen, Household energy choice in the ACT – Modelling and analysis, 2020
[34] Grattan, Flame out - the future of natural gas, 2023, Appendix

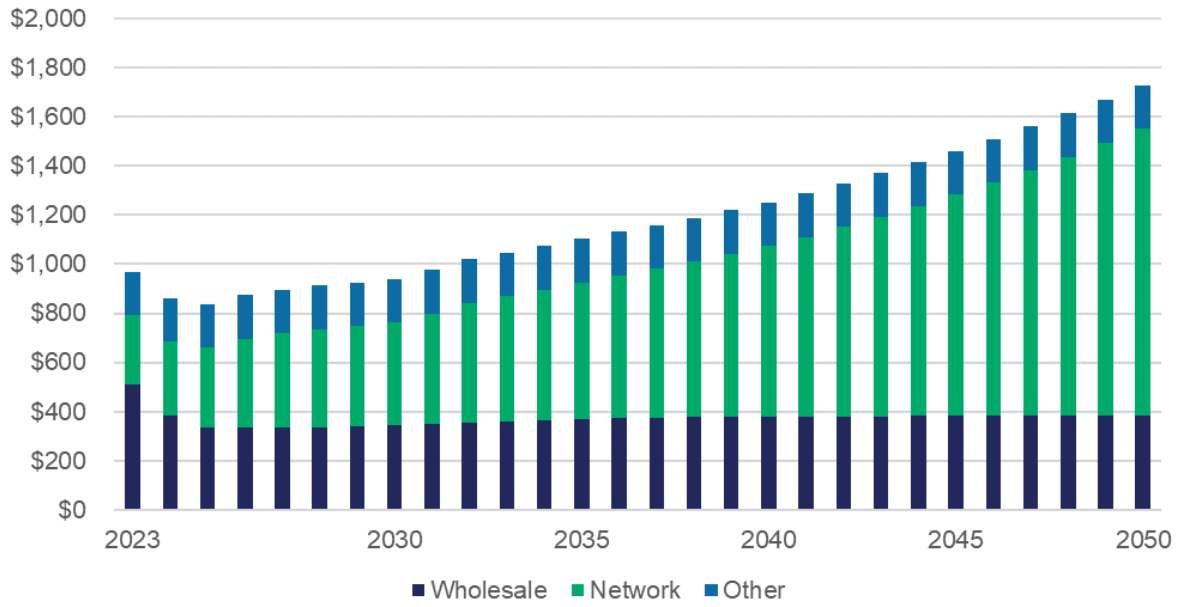
All-Electric New Homes Cost assessment	GHD	2022	new build	Victoria Gas Substitution Roadmap	All-electric lower cost and manageable on single phase
Are We Still Cooking with Gas?	Renew	2014	both	n/a	New homes cheaper to go all electric Existing homes dependent on multiple factors.
The Household Fuel Choice in the National Electricity Market	Renew	2018	both	n/a	New homes cheaper to go all electric. Existing homes dependent on various factors.
Flame out - the future of natural gas	Grattan	2020	New build	n/a	A new all-electric house is generally cheaper to live in than a dual-fuel house. Retrofitting was not specifically modelled.
Getting off gas: why, how, and who should pay?	Grattan	2023	both	n/a	Retrofitting NPV positive across all jurisdictions, with the exception of Perth homes without gas heating.
Castles and cars	Rewiring Australia	2021	retrofit	n/a	Large savings on average from electrification
Cost of switching from gas to electric appliances in the home	Frontier Economics	2022	retrofit	Gas Substitution Roadmap	Electrification could be costly, especially if replacing ducted heating, due to electrical upgrade costs

Source: Risks to gas consumers of declining gas demand, Boardroom Energy, February 2022, updated with some subsequent analyses

The economics of staying connected to gas will only get worse as other customers leave the network, and network charges per customer need to keep rising if gas distribution networks are to recover their costs. In a 2023 report for Energy Consumers Australia, CSIRO undertook modelling to determine the impacts to household energy bills under the Integrated System Plan's 'step change' or central planning scenario. The modelling showed that network prices on household gas bills would more than quadruple – from roughly $280/year today to $1,170 in 2050. Overseas industry observers have noted that the price impacts could be even more severe. Ofgem, the British energy regulator, states that "network charges could rise by a factor of 10 within 20 years."[35]

[35] Jan Rosenow, et. al. 2024 "The elephant in the room: How do we regulate gas transportation infrastructure as gas demand declines?, One Earth, Volume 7, Issue 7, pp. 1158-1161

Chart 1: Projected national average annual household gas bill with decreasing customer numbers



Source: CSIRO, Dynamic Analysis and ECA, Consumer impacts of the energy transition: modelling report, July 2023

These higher prices will inevitably cause more consumers to leave, creating a reinforcing spiral where prices continually increase until most remaining gas users are consumers without the agency or financial resources to leave the network. The precise timing and pace of the decline in gas demand is unknown. If gas consumers are especially price responsive and additional support is provided to go all electric, the decline could happen more quickly. If electricity prices remain high or increase and fewer consumers than expected adopt rooftop solar (reducing the prices they pay for electricity), then the decline may happen somewhat less dramatically.

The Commonwealth's *Future Gas Strategy* notes these issues and potential repercussions: "The rising cost of remaining on the reticulated gas network can provide the economic incentive to transition for those able to control – and afford – the cost of switching. However, renters, those in community and social housing, and low-income households, have limited or no control over whether they electrify, even where they might want to transition."[36]

We recognise that there are myriad challenges for consumers to electrify. The half (48%) of Australian households who rent or live in multi-family buildings will face additional barriers to going all electric. Renters rely on their landlord to invest in the necessary changes to enable electrification, but landlords have limited incentives to do so. Those in multi-unit buildings often rely on shared energy services, such as shared hot water provided by a central boiler. Large changes, such as shutting off gas supply, can require agreement from all unit owners in a building or complex.

Even detached owner-occupied houses can encounter barriers such as space limitations, wiring upgrades, and heritage listing. Barriers can also derive from people's personal circumstances, such as where they live, infirmity/disability, income, level of literacy, fluency in English, and access to internet and digital capabilities.

[36] Australian Government Department of Industry, Science and Resources, Future Gas Strategy, 2024. p. 41

While there is substantial research and evidence on the benefits for households to electrify, there is significantly less for small business. Large commercial and industrial customers may have fewer options for electrification (or finding some other net zero alternative to gas). Such customers are typically larger users and more likely to be connected to higher pressure parts of the network. It is certainly plausible (though by no means certain) that they may benefit from a renewable gas pathway to decarbonisation, and that there may be vestigial parts of the network retained to serve such customers.

However, there is no reason why other gas customers who will eventually electrify should underwrite a gas distribution network's transition to renewable gas. Conversely, if there is a small group of commercial users who still need reticulated gas, it's unlikely to be cost-effective for them to bear the full burden of cost recovery of assets that have been stranded due to other customers leaving the network.

We recognise that there are multiple factors that customers take account of in considering electrification. Some customers prefer gas for non-economic reasons and may continue to use it even as it becomes increasingly the costlier option. Such customers may prefer to use bottled gas if and when their part of the network is decommissioned or if reticulated gas becomes prohibitively expensive, provided they can do so safely at their premises.

As noted above, other customers may wish to switch but face barriers to doing so. We are especially concerned that such customers – often those least able to afford it – will bear the brunt of ever-increasing network charges if action is not taken now to find ways to reduce the costs gas networks can charge them.

Notwithstanding these factors, economic outcomes are a powerful driver and customer defection from gas networks will generate a positive feedback loop of higher gas prices making electric alternatives ever more financially attractive.

Some have suggested that renewable gases, particularly hydrogen and biomethane, can provide an enduring alternative to fossil gas for households and small businesses. Unfortunately, there is substantial evidence that renewable gas is not a viable solution for the main users of the gas distribution network: households and small businesses.

The Victorian Government identifies in its Industrial Renewable Gas Guarantee that electrification is the least cost alternative for household fossil gas use and will ensure any renewable gases are reserved for the most hard-to-abate industries. Their Directions Paper says: "Victoria's household energy consumption will be gradually decarbonised by electrification" while "renewable gases be deployed where there is no feasible decarbonisation alternative."[37] The ACT's Integrated Energy Plan also acknowledges renewable gases will only be used for some "niche applications."[38]

While many hope hydrogen has a role to play in replacing Australia's gas exports and some industrial gas use, the use of hydrogen by households and small businesses is economically inefficient and technically difficult. More than fifty independent studies on the use of hydrogen have concluded that hydrogen is inefficient and not recommended for heating buildings.[39] An exhaustive review of the peer-reviewed literature demonstrates that electrification is likely to always be more cost-effective than hydrogen.[40] It

[37] Victorian Government Department of Energy, Environment and Climate Action, Victorian Industrial Renewable Gas Guarantee Directions Paper, December 2024, p. 3.
[38] ACT Government, The Integrated Energy Plan 2024-2030, June 2024, p. 3.
[39] Rosenow, J. 2024, A meta-review of 54 studies on hydrogen heating. Cell Reports Sustainability
[40] Rosenow, J. 2022, Is heating homes with hydrogen all but a pipe dream? An evidence review.

cannot replace gas “in heating or consumer appliances above a 5 to 20 percent blend without enormous costs and disruption.”[41]

Unlike hydrogen, biomethane can operate without any modification to the existing gas network and is useable by existing gas appliances. Unfortunately, there is not enough domestic biomethane to replace Australia’s gas consumption. As a network-sponsored report summarises, “current projections of biomass in Australia indicate insufficient quantities will be produced to meet the scale required to entirely replace natural gas."[42] The Commonwealth’s Future Gas Strategy states: “biomethane is likely to be more valuable to gas users where electrification is not feasible.”[43]

According to the Bio-Energy Roadmap, the total annual production potential for biomethane in Australia is 371 PJ[44] – only 25% of annual domestic gas use.[45] Outside of residential and commercial users, the existing gas demand that must be decarbonised to meet 2050 net zero targets is 3 times larger than biomethane potential.[46] Australia’s limited biomethane supplies are likely to focus on this market because it is more difficult and expensive for it to electrify.

Today, biogas production is around 4TJ/year,[47] or 0.001 per cent of domestic gas consumption, and biogas will still need upgrading to biomethane. The infrastructure investment required for a biomethane future is also very significant – Jemena’s demonstration plant at Malabar is intended to have initial capacity of 95 terajoules of renewable gas per annum[48] (with no guarantee that production will reach that level). This is about equivalent to the average annual gas usage of 6,300[49] NSW homes. Even if there was enough feedstock, Jemena would need more than 200 such plants to supply all its household customers let alone its larger commercial and industrial customers. Meanwhile, as AEMO’s Integrated System Plan demonstrates, the electricity system is working to build the infrastructure required to meet the new load expected from electrifying gas.

Even if some parts of the low-pressure network are still used beyond net zero target dates (2045-2050 depending on the jurisdiction), the above analysis indicates that large parts of the network will no longer be used, and so there will be no customers left on those parts of the network to pay for any outstanding costs related to those parts of the network. Recently, AusNet Gas Services, one of the Victorian gas distribution networks stated in a letter to the AER what the above evidence demonstrates: “long term network decline is now inevitable.”[50]

An analogy commonly used in considering how monopoly networks should be regulated is that regulation should seek to mimic the pressures competition would exert in a competitive, unregulated market with a view to achieving similar outcomes. Accordingly, we consider it is reasonable to contemplate how a business such as a gas distribution network that was facing a permanent decline in demand would behave if it didn’t enjoy the regulatory protection of a regulated asset base (RAB). It would not assume that it would be able to recover costs through ongoing, exponential increases to its charges, given that many of its customers had viable alternative options.

[41] Sara Baldwin, et. al, “Assessing The Viability Of Hydrogen Proposals: Considerations For State Utility Regulators And Policymakers,” Energy Innovation, 2022.
[42] Deloitte, Decarbonising Australia’s gas distribution networks, December 2017, p. 79
[43] Australian Government Department of Industry, Science and Resources, Future Gas Strategy, 2024. p. 31
[44] Deloitte, Decarbonising Australia’s gas distribution networks, December 2017, p. 45
[45] DISR Future Gas Strategy Analytical Report
[46] DISR Future Gas Strategy Analytical Report
[47] https://arena.gov.au/knowledge-bank/biogas-opportunities-for-australia/
[48] https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/
[49] https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/
[50] Letter from David Smales, CEO Ausnet Services, to Clare Savage, Chair, AER, 30 September 2024.

A rational business in this situation would seek to reduce expenditure wherever possible, in particular minimising capex which might be difficult to recover in full over the longer term. In doing so, it would not neglect its statutory and regulatory obligations, but it would proactively seek change to those where they were an impediment to expenditure reduction and the underlying policy goals could be achieved more cost effectively. A corollary of this is that the network's customers would be better protected in the future against the risk of the business collapsing financially. This is the approach we consider that the gas distribution networks should be demonstrably taking, and the rules should be amended, to the extent they are able, to facilitate such an approach.

We have identified four key areas in which the NGR should be amended to better recognise and reduce the risks consumers face: connection fees, planning, depreciation, and capex criteria. We are proposing a rule change to address the issues with each of these areas. In sections 4-7 below we set out the issues, options and impacts of each of our proposed rule changes. We consider there is enough connection between each proposed rule change that the AEMC could engage in a single consultation process to consider all four. Equally we consider that each proposed change could be implemented independent of the others. We leave it to the AEMC to determine how best to consult on and consider these proposals.

In canvassing the issues as set out above, we are aware that some of these issues could be facilitated by a more holistic review of the relevant national laws and jurisdictional requirements as well as the NGR. For the avoidance of doubt, we consider that each of these rule change proposals has merit whether or not such other reforms eventuate, but we consider the benefits could be magnified with such reforms.

5 Capex criteria

5.1 What is the issue to be addressed?

Due to the risk of stranded assets arising from declining demand, it is essential that new capital spending (capex) on the gas distribution network is minimised to that which is absolutely necessary to meet the NGO. Currently, all scheme pipelines are subject to some broad principles for when it is appropriate to undertake capex, and these in turn guide the regulators' assessment of capex proposals. These are set out in Rule 79 – New capital expenditure criteria. This provides that capex is 'conforming' if it meets certain criteria.

The new capex must be "such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services in a manner consistent with the achievement of the national gas objective"

It must be "justifiable" on one of the following grounds specified in subrule (2):

- Overall economic value is positive;
- Economic value of the expected incremental revenue exceeds the capex; or
- Necessary – to maintain or improve safety or the integrity of services; to comply with regulatory obligation or requirement; to maintain provider's capacity to meet demand; or to contribute to meeting emissions reduction targets.

Lastly, it must be for expenditure that is properly allocated in accordance with the requirements of subrule (6).

If it does not meet these criteria, it is non-conforming and the pipeline service provider cannot add the expenditure to its RAB.

These criteria are intended to safeguard against inappropriate levels of capex and ensure that gas distribution networks and the regulators take account of the implications of declining demand. All potential capex should be considered through the lens of declining demand and the implications for cost recovery. In practice however, this is not occurring, evidenced by the fact that gas distribution networks persist with large claims for capex (at similar levels in most cases to previous periods) while simultaneously claiming the risk of asset stranding requires accelerated depreciation.

The propose-respond model provides the gas distribution networks with too much discretion in their presentation of capex business cases. While such a model may be appropriate for a network that is growing and expected to continue to grow indefinitely, networks projected to decline should invest in capital sparingly and only when absolutely necessary. Otherwise, they may increase the risk to consumers by over-investing in a network at risk of stranding. While one may argue that a rational network would not contemplate such investment, gas distribution networks are regularly proposing significant investments in new, discretionary capital. Frankly, the current system – predicated as it is on a network in growth phase – creates irresistible incentives for networks to seek ever-higher capex allowances. Arguably, this is only becoming more problematic in the current context in which networks may feel pressure to include some level of ambit claim in expectation of discounting from the regulator.

We appreciate the efforts regulators undertake to examine business cases, and we acknowledge that their examinations have resulted in decisions on capex lower than the gas network business proposals. However, regulators cannot analyse better value alternatives that are not being presented by networks.

Liberal use of confidentiality claims makes it even harder for consumers and other stakeholders to lodge robust objections to capex programs.

The asymmetry of the process is illustrated by AusNet's recent reopener application. While the ostensible driver of this reopener is the need to remove connections capex from the calculation of the price cap, AusNet has also taken the opportunity to claim additional costs and a greater quantum of accelerated depreciation. Meanwhile, despite claiming that the regulatory and policy framework has shifted materially since the AER's final decision, it sees no need to revise downwards other elements of its capex program (aside from a very modest adjustment to augmentation). The reopener is presented entirely on AusNet's terms. The AER has - in its draft decision – indicated that it intends to exercise its powers to refuse AusNet's application, but a more symmetric process might result in a reduction in AusNet's price cap rather than no change.

A review of recent access arrangements has identified some key themes based primarily on Multinet's 2023-28 AA and Jemena's 2026-31 proposal, which has yet to be determined by the AER.

- Obsolescence is sometimes cited as a justification for capex. Obsolescence does not mean an asset has failed or is about to fail, simply that the original equipment manufacturer (OEM) no longer supports that model and/or spare parts are becoming harder to find. Therefore, according to the gas distribution networks, proactive maintenance and refurbishment is no longer possible, and replacement is required. An example is Multinet's large consumer regulator strategy.[51] This issue needs to be further interrogated. While gas distribution networks cannot control OEMs' future decisions about when to discontinue a model, the prevalence of this as a justification calls into question whether this risk is being appropriately weighed up at the point of initial investment decision making. As gas networks decline globally, the rate of component asset obsolescence is likely to increase as the market for new gas network equipment declines. It's unclear what future costs and problems are being built in to networks by today's capex decisions.

- Cost-benefit analysis is often presented in purely qualitative terms. This is a problem in itself, and additionally makes it hard to assess whether the costs of emissions associated with alternative options have been appropriately accounted for as required under the revised NGO. An example is Multinet's Equipment Enclosure strategy.[52] The do-nothing option is rated high risk and the potential consequences are described qualitatively, using conditional terms such as "may" or "could". This does not mean that the do-nothing option is an appropriate option, simply that stakeholders aren't presented with the information to evaluate it against the presented options that include expenditure. Two costed options are presented, which have the same cost, but one defers some expenditure within the period. It's not clear to stakeholders why these represent the only two options worthy of consideration.

- Safety is typically cited as a rationale, often with no explanation of why that particular investment is the only (or best) way to meet safety requirements. While we do not advocate for compromising on safety, we consider that networks should investigate the potential for lower cost ways to meet safety, including exploring the option of seeking regulatory change to enable lower cost outcomes if required. While such analysis may have seemed a poor use of resources in times of network growth, they are now imperative, and the rules would benefit from explicit recognition of this.

- Reliability of supply is also often elided or merged with safety, even though it is a different criterion. In electricity networks, reliability investments are justified through a quantitative exercise, where a dollar

[51] MGN (Vic) - Attachment 9.15 - Large Consumer Regulator Strategy - July 2022
[52] MGN (Vic) - Attachment 9.17 - Plant and Equipment Strategy - July 2022, in particular Appendix A

value is placed on unserved energy avoided (the value of customer reliability), and the incremental cost of an investment needs to be exceeded by the value of the expected unserved energy avoided. In many cases, gas distribution networks treat reliability as if it is an absolute goal, describing the consequences of loss of supply in qualitative terms.[53] Given that gas distribution networks describe gas as a "fuel of choice," implying it is less essential than electricity, one would expect the value of customer reliability for gas to be lower than for electricity and for some level of unserved energy to be tolerable because it would cost more than it is worth to invest in higher levels of reliability.[54] The AEMC has received a rule change request from Energy Senior Officials that would require the AER to develop a value of gas customer reliability (VGCR) metric,[55] and this would assist better cost benefit analysis of reliability expenditure by providing an independent value of unserved energy to include. Of course, there has never been a barrier to networks undertaking their own analysis of this value in order to more robustly prove the case for reliability investments. We acknowledge that gas networks have to take different steps than electricity networks when re-energising a part of the network. For example, safety concerns may lead to network staff checking that customer appliances' pilot lights have been relit. Nevertheless, such activities can be costed and compared to the cost of the investment to avoid the outage.

- A common justification for capex is that the current asset is no longer fit for purpose. This does not mean it has failed or is about to fail, but that some defect has been identified. For example, Multinet has identified that some of its cathodic protection units are pole mounted and consider these to be less safe than the alternative.[56] But they are only pole mounted because Multinet installed them that way in the past and presumably have considered them safe enough (with appropriate risk mitigation actions) for much of their operational life. It's unclear both why there is now a compelling case for replacement and why customers should bear the full cost of both the old and new assets when it was Multinet's decision to install pole mounted units initially.
- Alternative options, such as demand management or strategic decommissioning appear to be rarely if ever considered as a potential option. The requirement to maintain a service provider's capacity to meet levels of demand must not preclude consideration of demand management as an alternative to investment, especially when demand is more likely to decline in the future than grow. (We note that AusNet is pursuing a demand management alternative to an augmentation project, which indicates that such approaches are feasible for gas networks, at least in some cases).
- We also consider there is an urgent need to investigate the economic viability of strategic decommissioning of parts of the network as an alternative to sinking further investment that risks getting stranded. An obvious case would be Multinet's extensive mains replacement program,[57] which is driving its capex higher than ever before even in the light of Victoria's gas substitution roadmap. This appears a perverse outcome. We recognise that Multinet's rationale is safety, but safety would be equally served by decommissioning the old pipelines. Even if barriers remain to executing a decommissioning project, it would be valuable to consider what the relative costs and benefits would be of decommissioning and assisting affected customers to electrify versus replacement investment. Notably, the former option would potentially avoid most or all of the future abolishment costs. Such an

[53] As an example, see MGN (Vic) - Attachment 9.15 - Large Consumer Regulator Strategy - July 2022, pp28-29
[54] The efficient level of unserved energy in gas may be lower than electricity today, given that most gas infrastructure is underground and so less exposed to weather, vegetation and accidental damage. But it is not zero, and may increase as use of the network declines and fewer reliability projects pass a robust cost benefit analysis.
[55] Energy Senior officials, ECGS Reliability standard and associated settings rule change proposal, July 2024
[56] MGN, (Vic) Attachment 9.16 Cathode Protection Strategy, July 2022
[57] MGN (Vic) - Attachment 9.7 - Distribution Mains and Services Strategy - July 2022

investigation can benefit many stakeholders beyond the gas network itself, including local and jurisdictional governments, electricity networks, and community groups. We are not aware of any barriers to Multinet exploring this option, noting that regulatory reform might be necessary to maximise the use of this option where cost-effective.

- Even where gas distribution networks are carrying out quantitative cost benefit analysis, careful attention must be paid to the assumptions. Commendably, Jemena have published numerous cost benefit cases alongside their draft proposal. However, they typically assume flat demand across the forward period. This is not consistent with Jemena's own future of gas analysis nor their claim for accelerated depreciation.
- In some cases, gas distribution networks are still attempting to include capex to support future use of the network for renewable gases. As has been discussed above, electrification is both a viable and a lower cost route to avoiding the emissions from natural gas. By contrast, renewable gases are yet to be developed at sufficient scale, are higher cost than natural gas (let alone electrified appliances) and may never become economically viable. Accordingly, a transition to renewable gases does not serve the long-term interests of most existing users of the gas distribution network, and to the extent such costs are recoverable from customers at all, they should only be recoverable from customers who are likely to benefit from such a transition and only to the extent they will benefit. While some proposed expenditure of this type has been withdrawn by networks or not allowed by regulators, we consider there would be value in a clearer statement in the rules to this effect. Notably, the non-scheme gas distribution networks in Tasmania and Queensland have not to date sought to transition their networks to accommodate renewable gases. These networks would have to self-fund such transitions.

While our analysis has focussed on capex, for similar reasons it is also necessary to minimise opex. The opex guidelines are limited to a short definitional description but include a clause that allows for "expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services."[58] We consider this clause to be effectively obsolete; it should be deleted.

5.2 What options have been considered?

There are a range of potential options that could mitigate this issue, but not all are equally robust or likely to be effective.

In principle, a more rigorous application of the existing criteria, particularly the test of "a prudent service provider acting efficiently" at subrule (1)(a) extracted in full above, could enable more careful and constrained spending on capex.

However, we do not consider the current criteria for when capex is "justifiable" under subrule (2) to be sufficiently effective in constraining capex in the context of network retreat. For example, the clause providing that capex is justifiable if it is necessary "to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)" (see 79(2)(c)(iv)) allows a gas distribution network to, in theory, fail to properly account for projected falls in demand or consider demand management as an option.

Our preferred option is therefore a change to the rules to provide certainty and consistency. Our view is that more prescriptive rules will be most effective at reducing consumer risk and will promote discussion of

[58] NGR, rule 69

the relevant factors to be included as part of this rule change process. The factors that should be considered are as follows:

- Capital expenditure should be justifiable on a robust quantitative cost benefit analysis, including a realistic assessment of asset lives and utilisation levels in the context of the targets set out in the emissions targets statement.
- The analysis should appropriately account for the impact of demand changes, including specifically:
  - alternatives to investments should be considered and if they cannot be considered a statement of reasons why not should be provided. The relative costs and benefits of inaction should be outlined.
- If asset replacement is sought before end-of-life, the gas distribution network should provide:
  - clarity on why replacement is required, including a comparison to a do-nothing approach;
  - clarity on why this eventuality was not foreseeable at the time of the original investment (and thus why customers are expected to pay in full for both the old and new asset);
  - information on how many consumers benefit from the replacement and the impacts on the value of the replacement expenditure if significant declines in consumers served by the asset occur; and
  - an explanation of how the gas distribution network intends to ensure similar issues do not arise with the new asset.
- Where there is an unavoidable regulatory driver for new expenditure, the gas distribution network should explain the steps it has taken to explore lower cost options with the relevant regulatory agency.

5.3 Description of the proposed changes to the rules

To give effect to our preferred option in the rules, it is necessary to amend Rule 79, which sets out the capex criteria. A range of amendments are required including the following:

- the introduction of explicit consideration of the impacts of declining demand;
- a requirement to consider alternatives to investment in replacement or new network equipment, including where relevant the provision of energy services by other means;
- clarity that the costs of capex to maintain the integrity of the network must be weighed against the value that customers place on avoiding loss of supply. (If the rule change request that the AEMC has received requiring the AER to develop a value of gas customer reliability goes ahead, then we would suggest referencing the VGCR here);
- clarity that future abolishment costs should be accounted for in cost-benefit analysis (noting that these may be lower or avoidable altogether in cases where a section of the network is decommissioned);
- a requirement for the regulator to assure itself that the service provider has acted prudently in its previous investment decisions before allowing capex to replace assets that were poorly sited/installed/configured or where the OEM has ceased to produce replacements and spare parts;

- a requirement for the service provider to demonstrate that it has explored lower cost options with the relevant regulatory authorities, where regulatory requirements are cited as the justification for investment; and
- the exclusion of capex on preparing to transport renewable fuels from reference services, so that such costs (to the extent they are conforming capex) can only be recovered from customers who wish to take renewable fuels in the future.

We think that some of these new requirements could be given effect by adjusting the following:

- Clarifying subrule (1)(a) to include context of the impact on demand for services of the need to meet national and jurisdictional emissions targets
- the factors in subrule (2)(c) for determining whether capex is "necessary", such as;
    - the removal of the words "and improve" from clause (1) of the subrule – noting that it remains essential to maintain safety.
    - to clarify that reliability should only be maintained to a level commensurate with the value that users of the service place on reliability.
    - in clause 3) of the subrule, to specifically allow for the meeting of regulatory obligations through discontinuance of a service.
    - In clause 4) to remove the reference to existing levels of demand and substitute in forecast levels of demand - considering the impact on demand for services of the need to meet national and jurisdictional emissions targets.
    - To clarify that the "supply of services" referenced in clause 5) could include provision of energy services by other means, whether by the service provider or another party.
- the considerations in subrule (3) laying out when the "overall economic value" of expenditure is positive including potential specification of the need to consider alternatives to investment; and
- the considerations in subrule (4) providing how to determine "the present value of expected incremental revenue".

It may also be necessary to include a new subrule defining circumstances in which capex is "not justifiable" and to clarify that capital expenditure on transitioning to renewable gases, even if justifiable, should only be allocated to a non-reference service, so that the general customer pool does not fund this expenditure.

We recognise that these amendments would by default apply to all scheme pipelines, but to the extent that they create some adverse unintended consequence in respect of transmission pipelines, we note that they could be made specific to distributors.

Similarly, we consider that part a) of the definition of operating expenditure in Rule 69: "expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services" should be deleted.

In light of our concerns, we question the continued fitness of aspects of Rule 80, particularly that it allows the AER to approve capex that has been made "in accordance with proposals made by the service provider and specified in the determination" without further consultation. Notably, this rule is not applicable in WA where the regulator applies additional scrutiny to past capex before confirming its inclusion in the

RAB. We consider that this rule can be deleted or at the very least clause 2 should be amended so that the AER must (rather than may) consult on whether it should approve the capex.

5.4 How will ECA's preferred option address the issue?

Our preferred option will address the issue by requiring greater rigour and transparency from gas distribution networks' capex proposals and the alternatives that have been considered. This will better enable stakeholders to respond to the proposals and provide the regulators with additional information to assist in their evaluation.

5.5 How do these rule changes contribute to the achievement of the NGO?

The changes will advance the long-term interest of customers by promoting more efficient investment in scheme distribution networks. We expect that as a result, capex will be lower, resulting in lower network charges than otherwise and also reducing stranded asset risk. Costs will be appropriately balanced against any impacts on the reliability of the network and security of supply. Safety will not be affected.

It will also avoid expenditure - both capex and opex - on increased demand that is now very unlikely to eventuate.

To the extent that the changes facilitate consideration of demand management and strategic decommissioning options as alternatives to investment, the changes will also contribute to the emissions reduction component of the NGO.

5.6 What are the costs, benefits and other impacts of the rule changes?

Costs

The direct costs of requiring the gas distribution networks to provide more robust justification for their capex proposals will be minimal. There may be some minor incremental costs as the gas distribution networks properly consider non-pipeline and other alternative options.

Benefits

Given that capex is currently running at c. $650m pa across the regulated gas distribution networks, even a one per cent benefit in lower capex would exceed any plausible estimate of costs. As well as contributing to lower costs in the short term, there would be longer term benefits in terms of a smaller RAB at risk of non-recovery due to stranding and consequently a lower risk of network financial distress. There may also be an emissions reduction benefit to the extent the rule changes facilitate alternatives to network investment.

Other impacts

Assuming that capex is reduced there may be some trade-offs, for example, there may be higher amounts of unserved energy if these changes result in lower capex to support reliability. This would only occur to the extent that it was cost-effective, i.e. the capex avoided was higher value than the cost of the additional outages.

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