Jemena Gas Networks (NSW) Ltd

Revised 2020-25 Access Arrangement Proposal

Attachment 8.2

Response to the AER's draft decision - Proposed changes to asset lives for new investments

Table of contents

Abbreviations

AA	Access Arrangement
ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CALD	Culturally and Linguistically Diverse
CCP	Consumer Challenge Panel
CEFC	Clean Energy Finance Corporation
COAG	Council of Australian Governments
Core Energy	Core Energy & Resources
CPP	Customer Challenge Panel
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESS	Energy Savings Scheme
GSOO	Gas Statement of Opportunities
IAP2	International Association of Public Participation
Incenta	Incenta Economic Consulting
IPART	Independent Pricing and Regulatory Tribunal
JGN	Jemena Gas Networks (NSW) Ltd
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net Present Value
PIAC	Public Interest Advisory Centre
UAG	Unaccounted for Gas
WACC	Weighted Average Cost of Capital

Overview

Our proposal and the two problems it seeks to address

Jemena Gas Networks (NSW) Ltd (**JGN**) has retained its proposal to shorten the asset lives for new investments in medium and high pressure pipeline assets. Doing so is essential to retain efficient investment incentives within the 2020-25 period because we must be afforded a reasonable expectation of recovering a normal return on the capital we commit.

We do not propose to change any remaining asset lives on existing investments we have already made. This means there is no change in our risk sharing with our customers for the $3.3B we have already invested.

Problem 1 – Our efficient investment incentives during 2020-2025

If the status quo is maintained for our new investments, we would be expected to commit a further $0.9B now based on a recovery period out to 2105 for high pressure pipelines and 2075 for medium pressure pipelines.

No prudent investor would subscribe to these conditions without financial compensation for the inherent stranding risk.

The Australian Energy Regulator (**AER**) does not compensate for that risk in its rate of return, instead affording us only the same rate of return (or weighted average cost of capital (**WACC**)) as it does for electricity networks who: 1) do not face stranding risk under the national electricity rules, 2) have asset lives that are no longer than 50 years, and 3) receive millions of dollars of AER-approved customer funding for future proofing and innovating their operations and service provision under the AER's demand management incentive scheme and demand management innovation allowance when no equivalent funding is afforded to gas businesses.

This AER rate of return decision leaves asset lives as the only regulatory lever to fix our investment incentives. This approach is absolutely appropriate because that is exactly what the gas law and depreciation criteria rules intend the regulated depreciation allowance to do, and what good regulatory practice and precedent support. However, the AER's draft decision has rejected our proposal stating we should wait for better evidence.

Problem 2 – Supporting future growth in the NSW gas market

Our proposal seeks a profile of cost recovery that supports lower gas prices in the future when everyone expects our customers to be facing higher costs across the gas supply chain. Put simply, there is no argument about whether decarbonisation policies will have an impact on gas prices. The debate is about the timing of the impact or about the best ways of mitigating the impact.

We are acting now for both the development of hydrogen as a substitute for natural gas and profiling of pipeline cost recovery to best support the future gas market. These actions are supported by our customers during our 20 month direct engagement program.

Our customers strongly supported us taking these actions. They recognised the benefits to future customers. In the case of this asset lives proposal, they were aware of the marginal reduction in our short-term price savings needed to make this possible. However, given that we are now proposing even greater network bill reductions than in our 2020 Plan, of $292 over five years[1], the $2.10 per annum impact of our proposal[2] is likely to be an imperceptible short-term commitment for a long-term gain that our current customers want to see action on.

1 Based on a coastal residential customer consuming 15 gigajoules (**GJ**) of gas.

2 This impact does not include the change to meter asset lives, which the AER has already accepted.

It is not preferable to adopt a "wait-and-see" approach

Contrary to the direct views of our customers in our award-winning engagement program, the AER's draft decision and several consumer representatives argue that we can wait to the next access arrangement (**AA**) review to have better information on the future of gas.

These views fundamentally misunderstand what the task before the AER is and what the resulting evidence threshold should be.

The task here is to adopt standard asset lives that provide us with the correct investment incentive as we invest capex during the 2020-25 period. The AER's decision must ensure we have a reasonable expectation of recovering our costs and a normal return during that period. It is these factors that would reasonably inform our expectations that establish the correct evidentiary threshold here.

The evidence threshold must also account for:

- The inherent flexibility that rule 89(1)(c) in the depreciation criteria provides to dynamically adjust the asset lives for the best information available at each AA review.
- The fact that our proposal is preferable to all alternatives for addressing this risk because it is net present value (**NPV**) neutral to us and our customers.

The evidence must relate to what is informing our cost recovery expectations

We now face:

- NSW climate change policies of zero net emissions by 2050 and 35% reduction by 2030.
- A current price of hydrogen seven times higher than the National Hydrogen Strategy estimates it needs to be for competitiveness in gas pipeline blending, and the strategy's expert engineers observing that recent UK experiences shows material conversion costs for gas distribution networks and our customers of as much as $7,708 per customer.
- Market operator and NSW Business Council concern of impending NSW gas supply shortfall as early as 2025.
- Developers and local governments phasing out natural gas as part of their stated emissions reductions strategies.

This revised proposal explores all these factors that drive both our cost recovery risk and our future customers' risk of higher prices if we fail to act now.

Our additional evidence

This attachment systematically responds to each of the AER's draft decision considerations and to the submissions made by consumer representative on this important element of our 2020 Plan.

We have held a further stakeholder engagement forum to explore the concerns of consumer representatives, and we have commissioned expert input to test and refine our proposal from the perspectives of technical engineering, rule compliance and preferability, and customer interest.

Our revised 2020 Plan has now been informed by the following reports which we discuss further in relevant parts of this attachment:

- **Attachment 2.1 | bd infrastructure - October stakeholder forum report**. This captures the insights and actions from our October workshop which covered: the regulatory framework, risk and risk transfer, investment versus market uncertainty, and customer engagement and advocate feedback on this proposal.

- **Attachment 8.3 | Incenta Economic Consulting - Using asset lives to manage stranded asset risks**. This report examines the economic principles for managing stranded asset risks in competitive markets and for regulated services, discusses how stranded asset risks can be managed within the current regulatory framework, identifies what approaches have been taken to managing stranded asset risks in other sectors and jurisdictions, and having regard to these matters, it critiques the AER's draft decision concluding that JGN's proposal is consistent with the requirements of the National Gas Rules (**NGR**), the National Gas Objective (**NGO**), and revenue and pricing principles.

- **Attachment 8.4 | Professor Cosmo Graham - Regulatory decision making and consumer voices**. This report considers our proposal, the differing views of our customers versus those of consumer representatives, and then assesses the regulatory framework and the circumstances for and consequences of ignoring the express sentiments of customers. It concludes that no circumstance exists for JGN that would warrant ignoring the stated views of our customers being ignored by the AER, and highlights the risks of ignoring these views.

- **Attachment 8.5 | GPA Engineering - Jemena NSW Gas Distribution Network Hydrogen Future Study**. This study identifies the technical impacts of 10% and 100% hydrogen (by volume) being blended in our network, and recommends required actions to support the transition by testing the asset and systems capabilities and identifying the facilitating investment requirements. It concludes that '*there will be significant investment required to transition to hydrogen in the gas network including potential accelerated and new capital investment*'.[3]

- **Attachment 8.6 | Core Energy - 2019-2070 Scenario-based outlook for JGN gas demand**. This report analyses the outlook for JGN's gas demand between 2020 and 2070, under a range of technology cost and decarbonisation policy scenarios.

Our revised proposal has also been informed by NSW government policy announcements and the national Hydrogen Strategy (discussed in section 2.1), along with material published by several of our key customers and their representative groups, including:

- **Attachment 8.7 | Mirvac - Planet positive: Mirvac's plan to reach net positive carbon by 2030**. This plan sets out how Mirvac will achieve its carbon target, including by ceasing reliance on natural gas for new builds and transitioning away from gas assets in existing buildings where replacement is economic (e.g. at end of life).

- **Attachment 8.8 | EnergyQuest - Running on empty: How to keep NSW fuelled for the future**. This report, commissioned by the NSW Business Council, urges immediate action from the NSW government to avert the 2025 NSW gas supply shortages that the Australian Energy Market Operator (**AEMO**) has forecast in its Gas Statement of Opportunity (**GSOO**).

In developing our 2020 Plan, we carefully considered how we should best support efficient future utilisation of gas and mitigate the risk and incentive consequences of us expecting not to be able to fully recover our investments. We considered a number of possible options that were available to us and included them within our proposal.[4] In addition to the options we previously considered, we have considered one new option. It reflects the UK approach, where asset lives are capped at 40 years, but would only apply to our new investments. This option, together with the other options we previously considered, is presented in Table 3-2. If this new option was adopted, it would increase bills by $1.29 per annum, which compares to the $2.10 per annum impact of our proposal.

Basis of financial information

All financial data included within this attachment is reported in the value of a dollar in 2020 and excludes impacts of inflation unless stated otherwise.

3 GPA, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page ii.

4 These were included within Table 2-1 of Attachment 7.10 of our 2020-25 AA Proposal.

1. Introduction

This section explains our initial 2020 Plan, the AER's draft decision, reasoning and feedback, our subsequent stakeholder engagement, additional evidence we have obtained to inform our revised 2020 plan, our revised 2020 Plan, and the structure of the rest of this attachment.

1.1 Our 2020 plan

JGN currently has 24 asset classes for the purposes of depreciating our regulated investments and our June 2019 2020 Plan (or 2020-25 AA Proposal) proposed retaining these asset classes. For the asset lives that apply to each of these asset classes, our 2020 Plan:

- Sought to align the standard asset lives[5] for new investments made from 1 July 2020 with our current and best view of their economic lives, which caused us to modify ten of the standard asset lives, but retain our 14 other asset categories' asset lives unchanged from those previously approved by the AER.[6]
- Retained the existing remaining asset lives that apply to investments we have already made.

For new investments we make on our network from 1 July 2020, we initially proposed hastening cost recovery for these new investments by adjusting the standard asset lives to reflect our current view of their likely economic lives.

Table 1–1 details the changes to asset lives that we proposed and their share of forecast new investment.

Table 1–1: Initial proposed changes to asset lives for new investments

Asset Class	Current standard lives (years)	Proposed standard lives for new investment (years)	Percentage of initial forecast capital expenditure in asset class compared to capital program as a whole
Trunks	80	50	0%
High pressure mains	80	50	13%
Meters/meter reading devices	20	15	21%
Medium pressure mains	50	30	15%
Medium pressure services	50	30	32%

1.2 Draft decision outcome and reasoning

The AER:

- Accepted our standard asset lives for 14 unchanged asset categories.
- Accepted our changes to the three metering-related asset classes (these being: contract meters, tariff meters, and meter reading devices) based on benchmarking against the asset lives of other networks.
- Rejected our proposed asset life changes for the six classes of pipeline assets.
- Accepted our new asset class for pigging and inspections.

5 The AER adopts terminology of 'standard asset lives' for the expected useful life of new assets, and 'remaining asset lives' for the expected useful life of existing assets, which we have also adopted herein.

6 The standard assets lives for following asset classes will remain unchanged: fixed plant – distribution, HP services, country POTS, buildings, computers, software, fixed plant, furniture, land (which doesn't depreciate), leasehold improvements, low value assets, mobile plant, vehicles, stock, equity raising costs. We are proposed to accelerate depreciation of existing pigging and inspection costs to better reflect to usage of these assets which the AER's draft decision accepted.

The AER summarised its reasoning for rejecting the changes to asset lives for future pipeline asset class investments as reflecting the following concerns:

- *AEMO data suggested that through until 2038, there is stable NSW commercial and residential gas demand under all forecasting scenarios. AEMO has also forecast a supply shortfall by 2030. However, there is a significant level of domestic gas production, an Australian Domestic Gas Security Mechanism and several interstate transmission pipelines commissioned, including the Northern Gas Pipeline (run and operated by Jemena). These indicate that network utilisation is less likely to be significantly impacted over the short to medium term.*

- *There is significant uncertainty around the NSW Government's policies on decarbonisation, and their potential impact on JGN's network utilisation. We are not aware of any policies that would have a direct negative impact on JGN's network utilisation.*

- *Higher depreciation and prices in the short term may accelerate any decline in utilisation. That is, higher prices (caused by accelerated depreciation) may discourage customers to connect to the gas network.*

- *Incentives for efficient capex. Our specific concerns are:*

  (a) Whether the capex is warranted – If utilisation of the network is expected to fall significantly, it would be questionable whether the capex should be approved in the first place. Rather than accelerating depreciation on new assets, providing service providers with incentives/funding to extend the lives of existing assets, instead of building new assets, may be preferable. Other alternatives, such as requiring greater upfront connection costs for augmentation, could also be a better solution for specific areas of concern rather than a change to a depreciation approach that affects all new assets and customers in the same way.

  (b) Accelerated depreciation can encourage early asset replacement – If the asset is largely depreciated before its useful life ends, the service provider may be encouraged to replace the asset sooner than necessary. The lower returns in later years (given the asset value has been quickly depreciated away) may provide incentives for early asset replacement to maintain prices at higher levels. More generally, it is questionable whether a service provider would be willing to continue to operate an asset for many years on which it is getting very little return, having recovered most of its money in the early years of the asset's life.

- *We do not consider that depreciation is an appropriate tool to reduce a network service provider's exposure to potential network-wide asset stranding risk. Stakeholders' submissions raised that the potential stranding of gas infrastructure assets is an industry-wide issue, with the ECA advocating for the development of a national strategy for addressing such issue.*[7]

In addition to the above, the AER's draft decision stated that:

- we had provided insufficient evidence that the proposed shorter standard asset lives would reflect the expected economic lives of these assets.
- the policy settings and gas usage forecasts we presented were in its view speculative. [8]

In this attachment we respond to each of these points. We also identify areas of the AER's draft decision and associated reasoning for other elements of our proposal where its positions directly contradict those relied upon in this decision to reject our standard asset life changes (see section 4).

7 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 9.

8 Ibid, page 15-16.

1.3 Our subsequent stakeholder engagement

Our pre-lodgement customer research program found that our customers supported our proposal to shorten some of our standard asset lives going forward. However, several consumer advocates have challenged whether this proposal is really in our customers' long-term interests. These challenges were outlined in submissions to the AER, and at a public forum on the proposal held by the AER on 7 August 2019.

Eight stakeholders made submissions to the AER on this element of our 2020 Plan. Section 3.7 provides our responses to each of these stakeholder's feedback.

In light of the issues in some of these submissions and in the AER's information requests, we convened a stakeholder workshop to further explore these themes, and provide additional evidence of the risks we face that drive the need for this change.

On 14 October 2019, we hosted a workshop to explore the issue of asset lives further, and seek a possible alignment with consumer advocates. This workshop was attended by representatives from the Public Interest Advocacy Centre (**PIAC**); Energy Consumers Australia (**ECA**); the AER Customer Challenge Panel (**CPP**), the AER, Incenta Economic Consulting (**Incenta**), and Jemena. It was facilitated by BD Infrastructure.

The agenda covered following discussion topics:

- The regulatory framework
- Risk and risk transfer
- Investment versus market uncertainty
- Customer engagement and advocate feedback

Outcomes of this workshop are set out in Attachment 2.1 and discussed where relevant throughout this attachment.

1.4 Our additional research and evidence

Various new evidence relevant to this proposed change has become available since both our Draft 2020 Plan and since we submitted our 2020 Plan to the AER. The AER's draft decision, for example, cites the 2019 AEMO GSOO which was published in March 2019. There have also now been definitive decarbonisation policy announcements in NSW, anti-gas policy announcements in the Australian Capital Territory (**ACT**) and a National Hydrogen Strategy published by the Council of Australian Governments (**COAG**). This attachment considers this new evidence.

We have also commissioned expert input to test and refine our proposal from the perspectives of technical engineering, rule compliance and preferability, and customer interest. Our revised 2020 Plan has now been informed by the following reports which we discuss further in relevant parts of this attachment:

- **Attachment 8.3** | Incenta Economic Consulting - Using asset lives to manage stranded asset risks. This report examines the economic principles for managing stranded asset risks in competitive markets and for regulated services, discusses how stranded asset risks can be managed within the current regulatory framework, identifies what approaches have been taken to managing stranded asset risks in other sectors and jurisdictions, and having regard to these matters, it critiques the AER's draft decision concluding that JGN's proposal is consistent with the requirements of the NGR, the NGO, and revenue and pricing principles.
- **Attachment 8.4** | Professor Cosmo Graham - Regulatory decision making and consumer voices. This report considers our proposal, the differing views of our customers versus those of consumer representatives, and then assesses the regulatory framework and the circumstances for and consequences of ignoring the express sentiments of customers. It concludes that no circumstance exists for JGN that would warrant ignoring the stated views of our customers being ignored by the AER, and highlights the risks of ignoring these views.

- **Attachment 8.5 |** GPA Engineering - Jemena NSW Gas Distribution Network Hydrogen Future Study. This study identifies the technical impacts of 10% and 100% hydrogen (by volume) being blended in our network, and recommends required actions to support the transition by testing the asset and systems capabilities and identifying the facilitating investment requirements. It concludes that 'there will be significant investment required to transition to hydrogen in the gas network including potential accelerated and new capital investment'.[9]
- **Attachment 8.6 |** Core Energy - 2019-2070 Scenario-based outlook for JGN gas demand. This report analyses the outlook for JGN's gas demand between 2020 and 2070, under a range of technology cost and decarbonisation policy scenarios.

Our Revised 2020 Plan has also been informed by material published by several of our key customers and their representative groups, including:

- **Attachment 8.7 |** Mirvac - Planet positive: Mirvac's plan to reach net positive carbon by 2030. This plan sets out how Mirvac will achieve its carbon target, including by ceasing reliance on natural gas for new builds and transitioning away from gas assets in existing buildings where replacement is economic (e.g. at end of life).
- **Attachment 8.8 |** EnergyQuest - Running on empty: How to keep NSW fuelled for the future. This report, commissioned by the NSW Business Council, urges immediate action from the NSW government to avert the 2025 NSW gas supply shortages AEMO has forecast in its GSOO.

1.5 Our Revised 2020 Plan

Our Revised 2020 Plan retains all elements of our initial 2020 Plan that were approved in the draft decision. It also seeks the following changes to standard asset lives for new investments.

Table 1–2: Revised proposed changes to asset lives for new investments

Asset Class	Current standard lives (years)	Proposed standard lives for new investment (years)	Percentage of initial forecast capital expenditure in asset class compared to capital program as a whole
Trunks	80	50	0%
High pressure mains	80	50	14%
Medium pressure mains	50	30	16%
Medium pressure services	50	30	33%

1.6 Structure of this document

The remainder of this attachment is structured as follows:

- Section 2 shows how JGN's risk is now even more certain than at the time of our June 2020 Plan, explains why it needs mitigating action now, outlines how material it will be to future customers if we don't take action now, and demonstrates how our proposal is supported by our customers.
- Section 3 presents our revised proposal, explains why this is both rule compliant and preferable to alternatives from the perspectives of rule compliance and customer impact, and responds to stakeholder submissions.
- Section 4 responds to each of the considerations raised in the AER's draft decision as a contributing reason for its rejection of our standard asset lives proposal.

9 GPA, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page ii.

2. The risk is real, present now and material to Jemena and to customers

In this section we:

- Evidence how this risk is manifesting now and is even more certain than at the time of our June 2020 Plan.
- Explain why it needs mitigating action now.
- Outline how material it will be to future customers if we fail to take action now.
- Discuss how our proposal is supported by our customers.

This section also responds to the following stakeholder feedback from our October 2019 forum held with customer advocates, AER staff, our economic advisors Incenta, and the CCP.

> **Box 2.1 Things to address from the October 19 stakeholder forum report**
>
> From these conversations, it was clear consumer advocates were keen to hear more from Jemena on the subject of risk: why it felt the risk to the future gas market was real and material; what risk assessment it had undertaken to arrive at this conclusion; and why it was necessary to act now to mitigate.
>
> In addition, advocates remained concerned that accelerating depreciation meant transferring the risk to consumers who did not necessarily have the resources to manage it. Advocates were keen for Jemena to reprosecute the case for why asset depreciation was in the long-term interests of customers.
>
> Finally advocates wanted to receive more context on why Jemena proposed to continue investing in the gas market while, at the same time, stating that its future was uncertain.
>
> …
>
> Advocates feel the materiality of risk needs to be established before considering regulatory tools to mitigate.

2.1 The risk is real

Decarbonisation policies and customer preferences for decarbonisation mean future gas customers simply:

- Will not use our gas network in the way they do now.
- Will not face gas or hydrogen prices as low as they are today nor on a relative par with electricity until at least 2050.[10]

While reasonable minds may debate the timing and materiality of these changes, the changes are inevitable. We cannot wait for perfect information to take action, and indeed on current best information, it is incumbent on our directors to ensure a risk of this materiality and probability[11] is being acted upon. We must act now on the best information currently available, and we can adjust in future as new information becomes available.

Failure to do this brings risk for our customers in that we cannot be expected to commit efficient levels of capital investment if there is every chance we won't ever recover that investment. If we curtail gas connection growth our current and future customers suffer through higher prices; if we curtail replacement or augmentation, our customers suffer through lower service performance and increased risk of public safety.

10 Deloitte Access Economics, *Decarbonising Australia's gas distribution networks*, November 2017, page 58–75.

11 At the October 2019 stakeholder forum, we presented our corporate risk assessment to stakeholders to explain how the risk consequence 'catastrophic' and probability 'possible' make this risk the highest rating 'extreme'. Our risk management framework is consistent with best practice including that it is consistent with ISO31000 Risk Management Guidelines.

Below we explain the policy settings and hydrogen feasibility and cost projections that drive this risk.

2.1.1 Policy setting is biased against natural gas and changing rapidly

Since we submitted our June 2020 Plan, we have seen a rapid acceleration of the policy move towards decarbonisation. Policy settings are even more aggressive than at the time of the initial proposal, and climate change is now one of, if not the top concern of most Australians.

While the AER draft decision concluded that: '*There is significant uncertainty around the NSW Government's policies on decarbonisation, and their potential impact on JGN's network utilisation*,'[12] any such uncertainty has now been removed.

Following community outrage at the early season NSW and Queensland bushfires and smoke blanketing Sydney and much of NSW, the NSW Minister for Energy and Environment, Matthew Kean has announced that NSW is preparing a new ambitious emissions reduction target to address climate change. It will commit to lowering greenhouse gases by 35 per cent by 2030 as explained in Box 2.2.

> **Box 2.2 NSW's 2030 emissions reductions target**
>
> The new target:
>
> - Of 35% by 2030 exceeds Australia's National Paris commitment of 26% by 2030.
> - Will not be measured by including any carryover Kyoto credits.
> - Bolsters NSW's previous target of zero emissions by 2050.
> - Has cabinet approval.[13]

Other than some elements of the National Hydrogen Strategy discussed below in section 2.1.2, state, territory and federal policy is biased to electrification and increasing the availability and interconnectedness of renewable electricity. Any policy intervention that underwrites or partially funds electricity investments in either generation, the transmission and distribution grid, or storage will necessarily lower its relative cost and thereby increase its competitiveness to gas. Unlike Victoria, gas is a fuel of choice in NSW and the plethora of incentives that enhance the cost competitiveness of electric appliances, use of electricity via roof top-solar and batteries, put at risk existing investments in the NSW gas distribution network.

Throughout 2019 we have seen material electricity policy interventions that will affect its relative cost competitiveness with natural gas in our pathway to our renewable energy targets and emissions reduction targets, including:

- In November 2019 the NSW Government launched its first ever state Electricity Strategy to deliver on its three objectives for the electricity system, these being electricity reliability, affordability and sustainability. Not only is there no equivalent state gas strategy, but the strategy includes measures that expand incentives for substituting away from gas, e.g.:

  > *The first component of the Safeguard will involve expanding the existing Energy Savings Scheme to 2050, with targets increasing gradually up to 13 per cent by 2030 and participants able to receive certificates for an expanded set of activities which reduce demand on electricity and gas networks, including substituting gas for biomass.*[14]

---

[12] AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, Nov 2019, page 46.

[13] Sydney Morning Herald (quoting the Minister), *NSW to commit to new emission reduction targets for 2030*, 12 December 2019.

[14] NSW Government, *Electricity Strategy*, Nov 2019, page 28.

- On 10 December, the NSW Minister for Energy and Environment committed that:

  'In addition to our Electricity Strategy, in the coming weeks and months we will also release our Net Zero Plan. The first fully funded plan in the nation to achieve our net zero emission goals.'[15]

- On 30 October the Australian Government announced the $1 billion Grid Reliability Fund which will be administered by the Clean Energy Finance Corporation (**CEFC**) covering eligible investments in:
  - energy storage projects including pumped hydro and batteries
  - transmission and distribution infrastructure
  - grid stabilising technologies.

- On 28 October the NSW Transport Minister announced plans to transform Sydney's buses into an electrified fleet and reduce their emissions to zero. This is notwithstanding the fact that hydrogen is widely seen as the likely least cost way to decarbonise major transport infrastructure. Commentators at the time observed:

  'The NSW Government is seeking proposals to shift Sydney's entire 8,000 strong bus fleet to an all-electric fleet in a landmark decision that marks one of the first tangible policies towards the state's goal of reaching zero net emissions by 2050.'[16]

- The Commonwealth Government has established the Underwriting New Generation Investments program to support targeted investment between now and 2023 in new electricity generation that will lower electricity prices, increase competition and increase reliability in the electricity system.

- On 27 June the South Australian Government granted Major Project Status, and in August the NSW Government granted Critical State Significant Infrastructure status to the Project EnergyConnect transmission interconnector between NSW and SA, which followed funding support for the initial project planning from the SA Government.[17]

We have seen more severe policy measures that are detrimental to the future viability and utilisation of the gas network. In particular, the ACT:

- On 10 December 2019 the ACT Government released for consultation its Draft Variation 373 which proposes to remove the mandatory requirement for gas provision to new suburbs contained in the Estate Development Code, Rule R43, in the Territory Plan. In doing so it states that:

  'This is in response to one of the key priorities of the ACT Climate Change Strategy 2019-2025 to encourage a shift from gas to electricity to reduce emissions from gas.'[18]

- In a 21 October 2019 letter to Energy Networks Australia, ACT Chief Minister Andrew Barr stated:

  'The ACT Climate Change Strategy sets forward a road map to net zero emissions by 2045. Achieving this target will necessitate no natural gas use in the ACT by 2045.'

- In September 2019 the Act Government released its ACT Sustainable energy policy 2020–25 discussion paper, which indicates that a key focus of the 2020–25 policy will be household transition away from natural gas and education on reducing natural gas consumption.[19]

15 The Hon. Matthew Kean, Smart Energy Summit Speech, 10 December 2019.

16 Michael Mazengarb, NSW unveils plan to switch Sydney's 8,000 buses to all-electric, 28 October 2019.

17 Dan Van Holst Pellekaan (Minister for Energy and Mining, SA), Interconnector gets Major Project Status, 27 June 2019, and The Australian, $1.5bn spark between states deemed critical, 29 August 2019.

18 ACT Environment, Planning and Sustainable Development Directorate, Draft Variation 373 - Removal of mandatory gas provision from Estate Development Code (stakeholder consultation email), 10 December 2019.

19 ACT Government, *ACT Sustainable energy policy 2020–25 discussion paper*, 6 September 2019.

2.1.2 COAG's Hydrogen strategy recognises the challenges gas networks face

In November 2019 the COAG Energy Council released Australia's National Hydrogen Strategy. This strategy recognises the challenges gas networks face, even though it seeks to support Hydrogen's use in gas distribution networks.

A key limb of the strategy is agreement on actions for facilitating clean hydrogen gas in Australia's gas networks. The strategy set out the following actions for this:

> ***3.11*** *Support continuing pilots, trials and demonstrations of hydrogen in gas distribution networks, where distributors can satisfy relevant regulators that:*
>
> - *The distribution network is comprised of materials confirmed to be safe and suitable for hydrogen blending*
> - *End user gas supply infrastructure (including installations and appliances) is safe and suitable for hydrogen blending*
> - *The distributor has adequate safety and training procedures in place*
> - *The effects of blending for gas network users of natural gas as chemical feedstock or for compressed natural gas have been considered and mitigated.*
>
> ***3.12*** *Agree to complete a review by the end of 2020. The review would:*
>
> - *Consider the application of the National Gas Law and relevant jurisdictional laws and regulations to hydrogen and advise the COAG Energy Council of recommended options to best address regulatory ambiguity, remove unnecessary regulatory barriers and improve the consistency of laws across jurisdictions.*
> - *Consider the economics of blending and of eventual use of 100% hydrogen in Australian gas networks.*
> - *Advise the COAG Energy Council recommend options for setting and allowing updates of upper limits on the volume of hydrogen allowed to be blended in gas networks. This will focus on keeping consumers safe, encouraging innovation and effectively managing any appliance readiness end user and market effect issues.*
>
> ***3.13*** *Agree to consider changes to gas networks and markets to allow widespread blending, and later sole use of hydrogen, where such changes:*
>
> - *Take place after the review at 3.12 and any actions that might arise from the review are completed*
> - *Carry acceptably low levels of safety risk*
> - *Are broadly supported by affected communities, and*
> - *Minimise impacts on gas prices and are in the long term interests of gas consumers.*
>
> ***3.14*** *Agree that, amongst other objectives, any government incentives to support the widespread blending of hydrogen in Australian gas distribution networks will:*
>
> - *Where appropriate, encourage blending to occur in a manner that supports the development of hydrogen hubs*
> - *Be consistent with the COAG Principles of Best Practice Regulation, in particular with respects to net benefits to consumers.*

> ***3.15*** *Agree to not support the blending of hydrogen in existing gas transmission networks until such time as further evidence emerges that hydrogen embrittlement issues can be safely addressed. Options for setting and allowing for ongoing updates of safe limits for hydrogen blending in transmission networks will form part of the review in 2020.*

The strategy was informed and accompanied by a report commissioned from expert engineers, GPA Engineering. The report 'Hydrogen in the Gas Distribution Networks' identified, among other things, that:

- *More gas must be transported* | Hydrogen will require greater capacity and flows of gas. Blending hydrogen into the gas pipeline networks will reduce network storage and flowing capacity due to lower heating values and gas blend densities, possible gas quality variations into the network, and non-uniformity of higher heating value within the network. Although a gas network is used to transport a physical gas, commercial contracts and billing are calculated in energy content, rather than by volume or mass. GPA Engineering estimates that the magnitude of the capacity loss with a 10% hydrogen blend is on average estimated as approximately 2.4%.[20] Other things being equal, this can be expected to make JGN's gas transportation services more expensive in the future.
- *Hydrogen will affect some materials used in gas networks* | Not all materials currently in use in gas networks are known, and some that are known to be used are also known to be affected by embrittlement when exposed to hydrogen.[21] This particularly affects steel pipelines which is what JGN's high pressure trunks and high pressure primary mains are made of.
- *Gas measurement devices must be reviewed for use with 10% hydrogen* | GPA Engineering recommend a review of the technical and commercial suitability and integrity of gas measurement and metering devices installed in the distribution networks be completed for addition of up to 10% hydrogen. This is to ensure that gas measurement equipment used for flow regulation and billing is accurate and safe for hydrogen concentrations of up to 10%. GPA Engineering identifies that some may require replacement, and others may be able to be recalibrated.[22]

These COAG and GPA Engineering findings have direct implications for the likely technical lives of JGN's asset classes. We explain these in Table 2–1.

Table 2–1: Implications for asset classes we seek to change

Asset Class	Current and proposed standard lives (years)	Implications
Trunks	80 → 50	Our trunks are large diameter (up to 864mm[23]) and until a 2009 reclassification approved by the National Competition Council for their economic and usage characteristics, they were deemed transmission pipelines under the NGL.[24] These assets are steel and operate at high pressure (6.9 MPa). The National Hydrogen strategy action 3.15 agrees not to support hydrogen in transmission pipelines on current information.
High pressure mains	80 → 50	JGN's high pressure primary mains are steel and may be affected by embrittlement if exposed to hydrogen.
Meters/meter reading devices	20 → 15	GPA Engineering identifies that some may require replacement, and others may need to be recalibrated to allow accurate metrology with blended hydrogen.

20 GPA, *Hydrogen in the Gas Distribution Networks*, 2019, page 35.

21 Ibid. page 40-43.

22 Ibid. page 37-38.

23 JGN, *Pipeline reclassification application*, 22 April 2009, page 25.

24 NCC, *Jemena Pipeline Reclassification | National Gas Law: Application by Jemena Gas Networks (NSW) Limited for reclassification of the Northern Trunk and Southern Trunk pipelines - Final Decision and Statement of Reasons*, 29 June 2009.

Asset Class	Current and proposed standard lives (years)	Implications
Medium pressure mains	50 → 30	Require a materials audit
Medium pressure services	50 → 30	Require a materials audit

Significant work is needed to assess the feasibility of and facilitating investment for JGN hosting hydrogen

We recently commissioned GPA Engineering to assess the technical impacts of 10% and 100% hydrogen (by volume) being blended in our network, and develop the high level actions to support the transition by testing the capability and identifying the facilitating investment requirements. Its report is provided as Attachment 8.5.

GPA Engineering reports that:

> *Transporting either pure hydrogen or a hydrogen / natural gas blend would have technical implications for the operation of the Jemena gas network. The introduction of hydrogen would impact the network capacity, require capital works to effect the transition, and in some contexts could reduce the remaining life of the asset.*[25]

GPA Engineering sets out a program of assessments and reviews needed to prove JGN's hosting ability and conversion investment requirements. It also observes that:

> *There is uncertainty around the impact of embrittlement to the trunk and primary mains. Where they were identified not to be hydrogen compatible, it will need upgrading or replacement, which would involve significant capital investment.* [26]

2.1.3 Hydrogen is a long way from viable let alone economic

The relevant driver of the economic life of our assets is how economically viable gas is as a cost competitive alternative to electricity. Existing gas demand and the accepted past practice of relying on technical lives for determining economic lives were underwritten by an economic context of gas being cost effective alternative to electricity, and the presumption that gas distribution networks would continue to operate in perpetuity.

That now isn't the case on current wholesale gas prices let alone when hydrogen is more expensive and renewable electricity has zero marginal cost with fixed capital costs dropping rapidly.

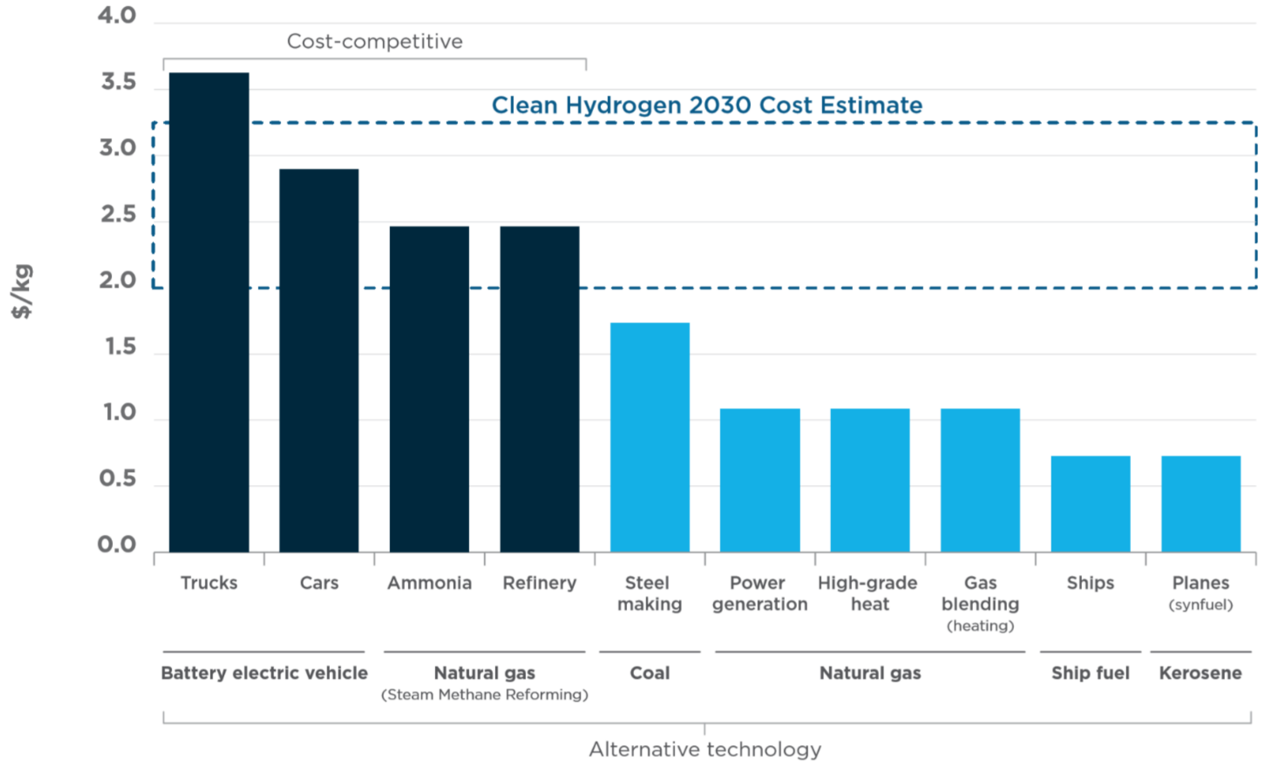
Even if found to be technically viable, hydrogen is not expected to aid the cost competitiveness of gas any time soon. JGN's green gas trial is focused on slowing an expected decline in the usefulness of our network, not stopping it, and certainly not over the next five years.

The National Hydrogen Strategy published estimates of the cost competitiveness of clean hydrogen by 2030 as shown below. These estimated the breakeven cost of hydrogen for blending into natural gas needs to be $1.20 for a kg of H_2 to deliver the equivalent heat of 1 GJ of heat using natural gas and assuming a wholesale natural gas price of $10/GJ. This is materially below the lower bound hydrogen cost estimate of $2 per kg of H_2.

[25] GPA Engineering, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page 14.

[26] GPA Engineering, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page 31.

Figure 2.1: Breakeven cost of hydrogen against alternative technology for major applications, in 2030



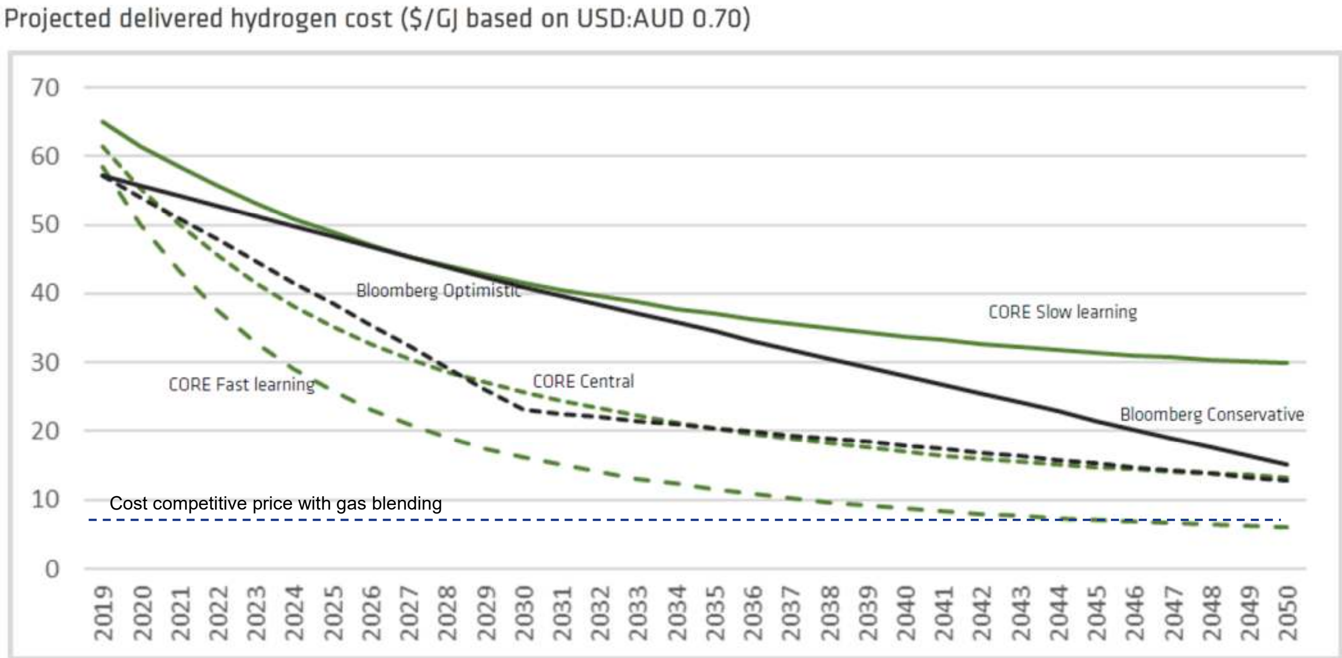
Source: COAG Energy Council, *Australia's National Hydrogen Strategy*, November 2019, page 6.

Our demonstration project is estimating that the marginal production cost (ignoring sunk capital) will depend on electricity price, and at 15c/kwh it is $7/kg.

Current expert forecasts of hydrogen cost presented in Core Energy's 2019-2070 Scenario-based outlook for JGN gas demand (see Attachment 8.6) show that only one of these forecasts (Core Energy's fast learning scenario) gets to the hydrogen price needed for competitiveness in gas blending by 2050, $8.5/GJ.[27]

[27] 1Kg of H_2 = 0.142GJ of natural gas on an energy equivalence basis (or 7kgH_2 = 1GJ), so $1.2/KG is ~ $8.5/GJ.

Figure 2.2: Hydrogen cost projections from various expert forecasters ($2018 AUD, $/GJ)



Source: Core Energy

We also note that it is not just sufficient for the hydrogen commodity price to be competitive. Our network costs and customers' conversion costs will also affect the extent to which hydrogen becomes viable. GPA Engineering observed that:

> *100% hydrogen conversion studies completed in the UK indicated that replacement and upgrades to the distribution network and gas appliances would be required, resulting in significant financial impacts. The H21 project in Leeds (UK) estimated that the average cost of conversion per connection, including gas network and appliance upgrades was £4,028 ($7,708 AUD).*[28]

2.2 The risk is present now for the purposes of investments JGN must make in the next AA period

JGN's current risk is material

The AER's draft decision approved that we need to invest $791.1M ($2019–20) of total net capex for the 2020–25 AA period because it independently viewed this as conforming capex under the NGR. While our revised proposal considers this allowance needs to be higher, even this draft decision shows that a material amount of investment is needed to maintain our network and meet customer demand. While the AER draft decision rejected our asset lives proposal on a fear of potential over investment when the assets are fully depreciated after 2050 for medium pressure assets and after 2070 for high pressure assets, the issue here is actually an incentive for under investment during the 2020-25 period.

We are committed to making the necessary investment, but only where it is commercially prudent to do so. We cannot be expected to invest amid the present level of cost recovery risk, particularly for the period after 2050. Beyond 2050, we already bear significant risk for our existing investments that are not affected by our proposed change. Under a stable demand scenario where JGN is expected to invest capex at current levels, our proposed approach lowers the investment risk only marginally because in 2050 we are expected to still have $2.5B in unrecovered investment.

[28] GPA Engineering, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page ii.

In a situation where the regulator is not allowing us to be compensated for that risk – either in the WACC which is the same as electricity networks who don't face such risk[29], or in a proper application of the depreciation criteria – we cannot be expected to compound our current risk by spending a further $0.9B by 2025.

JGN's ability to mitigate this risk is prospective at the time it commits to an investment. The '*wait and see*' logic presented in the draft decision and raised by some stakeholders simply doesn't address the risk of us being unwilling to optimally invest during 2020-2025. Investing additional capex when our corporate risk assessment, following good industry risk practice, would be contrary to the duties of our directors.

At the October stakeholder 2019 forum, we presented our corporate risk assessment to stakeholders to explain how the risk consequence 'catastrophic' and probability 'possible' make this risk the highest rating 'extreme'. Our risk management framework is consistent with best practice including that it is consistent with ISO31000 Risk Management Guidelines.

Our risk is not just policy-driven

Our risk is not only driven by State and Federal policy changes, but also by:

- Behaviours we are seeing among developers, our commercial customers and some local governments, and
- Expectations of gas supply shortfall into NSW.

We discuss AEMO and our customers concerns about NSW gas supply shortfalls in sections 2.3 and 4.4. Below we consider the customer changes that are driving the gas market growth risk that our proposal seeks to mitigate.

Major developers are moving to lower the carbon footprint of their future developments. For example, Mirvac has released its strategy for net positive carbon by 2030 in which it states:

> *It's undeniable that we need to reduce our reliance on natural gas and other fossil fuels, but this transition will not be without challenges. Within the property industry, we have become heavily dependent on natural gas for heating and hot water, as it's been viewed as a lower emission alternative. We've also become reliant on co-generation, partly due to the way in which high rating NABERS and Green Star building certifications are awarded. In recent years, co-generation has certainly helped Mirvac to reduce emission intensity, and it still has value as a transition strategy.*
>
> *To achieve net positive carbon, we will need to embrace a new 'fossil-fuel free' mindset, and encourage our peers to do the same, a need for advocacy that has been highlighted by the Green Building Council of Australia's (GBCA) Carbon Positive Roadmap.*
>
> *With our integrated development capability and healthy development pipeline, Mirvac is in a strong position to eliminate fossil fuels from our new developments.[30] However, we recognise that the shift will take longer in our existing buildings, which are not always straightforward to retrofit, especially in cooler climates where buildings have traditionally relied on gas heating.[31]*

Mirvac's projected emissions are shown in Figure 4-2. They show that grid-delivered gas will still play a significant role in its energy supply in the coming decade. However transitioning away from fossil fuels is a key part of Mirvac's strategy. This includes a commitment for existing assets whereby it will investigate electrification options when replacing natural gas plant equipment from financial year 2020.[32]

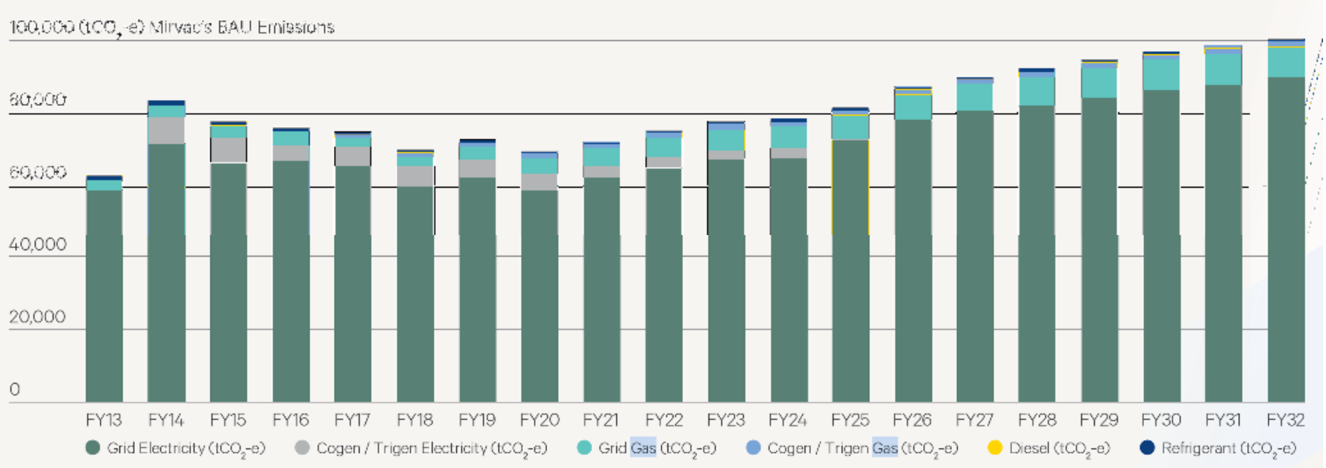
29 Either in the regime, because there is no NER rule provision equivalent to NGR rule 85, or in the market for their services because the decarbonisation policies are aimed at electrification and better use of the interconnected system to move renewable energy from remote wind and solar generation sites to loads and build resilience though distributed energy resources.

30 Mirvac footnote quote: '*Eliminating natural gas from our new developments can occur from as early as FY20. Removing diesel (associated with emergency backup generation) is dependent on a viable alternative becoming available.*'

31 Mirvac, *Planet positive: Mirvac's plan to reach net positive carbon by 2030*, July 2019, page 6.

32 Ibid, page 13.

Figure 4–3: Mirvac's projected emissions by source



Source: Mirvac

We also face risk of local government (who approve most housing and urban development plans), seeking to reduce use of gas. On 3 December 2019 the Councils Beyond Gas Forum was held in Melbourne to discuss alternatives to the traditional use of gas at a municipal level. Agenda items included case studies in a municipality committing to phase out gas, and gas-free building refurbishment, along with council strategies for gas phase out.

Other developers and organisations that have committed to achieving low or net-zero carbon emissions include Dexus, the City of Sydney Council and Interface carpets. These organisations have all indicated their support for JGN to develop biomethane injection projects with the aim of enabling our customers to purchase renewable gas, delivered via our JGN network.[33] (see Attachment 4.2 for more details).

What would a prudent operator in JGN's shoes do when facing this risk?

The consequences of JGN not being provided with an expectation of recovering its costs are well recognised in economic theory. We commissioned Incenta to examine what economic principles tell us about how to manage stranded asset risks in competitive markets and for regulated services. In doing so Incenta has explored the expected consequences of failure to adequately do this.

Incenta identifies that:[34]

> *First, to the extent that firms do not expect to recover cost – and hence expect to achieve a normal return on investment – then investing in the regulated activity will yield poorer returns than available in alternative activities when adjusted for the relative risk. It follows that the firm would no longer have a financial incentive to invest in the regulated activity, but instead would have the incentive to reduce this to the extent possible.*

Incenta goes on to state that the consequences of this:[35]

> *…would be expected to lead to a number of undesirable outcomes, including:*
>
> - *cessation or deferral of discretionary projects, which may include projects associated with extending the network to new areas or improvements to existing services*

33 Each of these organisations has written to JGN in support of our proposed Malabar biomethane project. See Attachments 4.2 and 4.8.

34 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 14

35 Ibid. page 14.

- *a substitution from capital expenditure to operating expenditure where this is possible,*[36] *even where this comes at higher cost to customers*
- *a deferral of asset replacement where possible, and a possible increase in the risk of outages, and*
- *a general reduced preparedness to investigate or explore new initiatives that may require investment.*

Incenta also points out that:[37]

> *Secondly, providing the expectation that regulated business will be able to recover their costs (at least if reasonable hurdles for prudence and efficiency are met) is a key part of the arrangements in utility regulation to secure a fair balancing of the interests between regulated businesses and their customers. That is, utility firms agree to undertake irreversible investment and recover that over an extended period and submit to service obligations, and in return are permitted to recover their costs. Similarly, customers are protected by ensuring that prices are limited to cost, those costs are spread fairly over time and reasonable service levels are assured.*

These undesirable effects of a failure to allow us a reasonable expectation of a normal return are a genuine threat in the 2020-25 period. That fact that such incentives would be a real risk under both our current and proposed standard asset lives is illustrated in **Table** 2–2. The table shows that the proposal in no way eliminates JGN's asset stranding risk, nor guarantees cost recovery before the 2050 net zero emissions target date. Rather this is a measured step to preserve our incentives during 2020 to 2025.

Table 2–2: Implications for asset classes we seek to change

Asset Class	Current and proposed standard lives (years)	Change in final year of cost recovery for assets to be invested during the 2020-25 period
Trunks	80 → 50	2105 → 2075
High pressure mains	80 → 50	2105 → 2075
Medium pressure mains	50 → 30	2075 → 2055
Medium pressure services	50 → 30	2075 → 2055

2.3 The risk is material for future customers

Our customers are concerned about the future availability of affordable gas after 2025

In December 2019, the NSW Business Chamber published a report prepared by EnergyQuest titled '[Running on empty: How to keep NSW fuelled for the future]'. When releasing this paper, NSW Business Chamber Chief Executive Stephen Cartwright said:

> *In less than six years, NSW is projected to face serious gas shortages. If additional gas supply is not sourced, NSW will face crippling price rises, forced business closures and job losses right across the state. As a minimum, costs that gas-using businesses incur from gas price rises will be passed on to their customers or will erode their profitability.*

36 There may also be an incentive to substitute capital expenditure from items that have a high capital cost but long life or low operating expense to lower capital cost items with a short life or high ongoing cost, even if this raises overall cost to customers.

37 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 15.

> *NSW gas users have already seen prices triple over recent years. Poor planning and a lack of action to develop significant gas resources in this state have resulted in NSW suffering the most expensive gas in mainland Australia and the least certainty with respect to gas supply security.*[38]

EnergyQuest observed that:

> *Commercial and Industrial gas users are reported to be postponing pay increases, reducing headcount, and deferring investments or expansions. Some have closed altogether, blaming high gas prices. These effects are not limited to the biggest users. A typical commercial bakery in Sydney will pay an extra $26,400 per year for gas compared to a bakery in Brisbane. A galvanising plant in NSW would pay $66,000 per year more than a Queensland competitor.*[39]

EnergyQuest's report highlights that even without carbon reduction policies, supply side restrictions have the potential to contribute to demand reduction and lower utilisation of the network in the near to medium term.

The Energy Quest report recommends several immediate actions to help avert this shortfall, including facilitating the LNG import terminal construction for NSW at Port Kembla to begin by 2022. We discuss these in Table 4–1.

Our customers are concerned about the future

Our customers are concerned about the future and that basing decisions on historical approaches won't work going forward. They said as much during our engagement and research program:

> *Participants are concerned about the future. Although participants understand, and are on the whole comfortable with, what Jemena is planning for the future, and why, they would like more information about how Jemena are responding to uncertainty. They expressed nervousness about what the next generation will be faced with in terms of their energy choices and expenses (beyond 2020-2025). They wanted some more detail about research and development and investment in innovation. Some suggestions included:*
>
> - *sustainability of future gas resources*
> - *ease of switching to hydrogen and this research area,*
> - *the challenge of making future decisions based on historic data in an era of disruption and innovation.*[40]

We agree that historical data won't be the best source of decision making for the future. Our decision to review our standard asset lives, instead of relying on past 'generally accepted technical lives', reflects this. This need for foresight must be accounted for in the evidence base the AER considers for this proposal, rather than a reliance on historical data, legacy generally accepted asset lives and benchmarking against peers who are either not yet facing the scale of market change that JGN is, or have simply not had the opportunity to propose similar changes based on their regulatory cycles.

Our proposal lowers future risk for our customers

As we explain in section 4, our proposal will support lower gas prices in the future and thereby alleviate the bill impacts gas users may see from either higher wholesale gas prices, increased transportation costs to get gas to NSW or the higher unit costs of hydrogen.

This risk to future customers gets worse if options other than the one we are proposing need to be enacted now or later, as explained in section 3.6.

38 NSW Business Chamber, *Media Release | Running on empty – NSW to run out of gas by 2025 if action not taken*, 3 December 2019.

39 EnergyQuest, *Running on empty: How to keep NSW fuelled for the future*, December 2019, page 4.

40 RPS, *Jemena Gas Networks | Draft 2020 Plan Consultation Report*, 10 April 2019, page

2.4 Our proposal is supported by our customers

Our engagement with our direct customers on this proposal was extensive and is recognised as being so. It showed they expect us to act for the future, and supported our proposal to do so. In this context, it would be wrong to favour the views of consumer advocates over those of customers.

As Professor Graham observes:

> *A regulator can reject consumer and stakeholder views if they are contrary to the legislation or to an expressed government policy that the regulator is bound to follow. This is not the case here. … Rejecting express consumer views will have negative consequences: companies will have less incentive to take consumer engagement seriously and consumers will be less inclined to engage.*[41]

2.4.1 Our consultation with customers was robust

Given the importance of this issue, and its impact on our revenue requirements in the 2020 Plan period, we consulted with our customers on our proposal at multiple stages of the engagement program. Integral to our engagement was the effort to understand – at different stages of the engagement journey - whether they would support our proposal to speed up the recovery of our new investments in the proposed asset classes.

This extensive engagement has been recognised by others.

> AER draft decision: *We note that JGN has undertaken a significant customer engagement program to inform its 2020–25 proposal.*[42]
>
> *CCP19 acknowledges that through a thorough consumer engagement process JGN has received feedback supporting its proposed acceleration of depreciation.*[43]
>
> *PIAC commends the consumer engagement that Jemena has conducted in the lead up to preparing its initial proposal for the 2020-25 access arrangement…..The discussion of more fundamental topics in a manner that allowed for meaningful and informed input, such as accelerated depreciation, directly with customers through the deliberative forums and with consumer representatives such as PIAC should be commended.*[44]
>
> ECA*: Jemena Gas Networks (JGN) has followed an exemplary consumer engagement process to help it understand the long-term interests of consumers.*[45]

We also won an award from the Energy Networks Australia in September 2019 for the quality of our 2020-25 AA review engagement program, of which the judging panel comprised members from the AER, ECA, PIAC, the Australian Energy Market Commission (**AEMC**), St Vincent de Paul, Uniting Communities, and Council of the Ageing.

In this context, where JGN has invested heavily in robust engagement and our customers have invested considerable time, it is incumbent on the AER to place sufficient weight on the outcomes of that engagement. We acknowledge that may not be the case where our engagement was deficient, but that is simply not the case here, as Professor Graham observes:

> *A reason for rejecting the views of consumers as reported by Jemena would be if those views were in some sense not valid or representative (the representativeness point is discussed below). An inappropriate method could have been chosen or an appropriate method could have been badly or improperly executed. So, for example, a sample could be unrepresentative, the questions asked*

41 Professor Cosmo Graham, *Regulatory decision making and consumer voices*, December 2019, pages 3 and 4.

42 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, Nov 2019, page 15.

43 CCP19, *Consumer Challenge Panel Submission to the AER on JGN's Regulatory Proposal*, 9 August 2019, page 34.

44 Public Interest Advocacy Centre, *Submission to Jemena Gas Networks' 2020 Plan*, 9 August 2019, page 4.

45 Energy Consumers Australia, *Jemena Gas Networks Draft 2020 Plan*, Submission, March 2019

> *could be inappropriate or biases have not been accounted for. None of these issues arise in this case and there has been no criticism, in the documentation I have seen, of the methods used by Jemena.*

A better AER decision is one that reflects the direct view of our direct customers; otherwise, the recognised industry-leading engagement has come to nought.

JGN and other network companies will be disincentivised to engage authentically with customers where it does not influence customer-driven regulatory outcomes. Similarly, future customers will be hesitant to invest time and effort into regulatory process if their voices are not being reflected in regulatory decisions.

2.4.2 Our customers supported our plan

Most customers supported a change to the asset lives. Customers told us that they want us to take a proactive approach to managing future uncertainty and to minimise any negative customer consequences.[46] They saw this as a way for current customers to do a little now to protect future generations from much more significant price implications. Even though they are generally positive about the future of gas, this approach was considered appropriate, as it also pays off the asset sooner, thereby reducing future bills if the asset thrives. Customers also preferred this approach as something that could be revisited as the future becomes clearer without impacting service quality or availability.

In light of the strong support from our customers, we incorporated the change to asset lives for new investment into our Draft 2020 Plan published in January 2019. When we then tested that we had accurately captured their preferences on this topic in our plan, customers again voted overwhelmingly in support of this proposal. A significant majority (78%) of customers considered that we had responded very well or quite well to their feedback in this area, and 90% of our customers strongly or moderately agreed that our Draft 2020 Plan was in their long-term interests.

Given the strong positive response from our customers, we included the approach in our 2020 Plan and are retaining it in our Revised 2020 Plan.

2.4.3 It would be wrong to favour the views of consumer advocates over those of customers

We acknowledge that a range of consumer advocates have not supported our proposal to act now to protect the future use of gas and affordability thereof for our customers. For example, CCP19 states:

> *CCP19 acknowledges the support for this proposal from JGN's consumer engagement, however considers that notwithstanding the consumer sentiment it would not be in the long-term interests of consumers to implement the proposed accelerated depreciation until there is greater certainty as to the demise of the gas network.*[47]

We consider it would be remiss of the AER not to place significant weight on the views of our customers. Because the presence of opposing views between customers and their advocates and the CCP may place the AER in an unenviable position of needing to choose between them, we sought expert advice on this.

We engaged Professor Cosmo Graham of the Leicester Law School, University of Leicester to examine the situation, the regulatory framework and the circumstances for and consequences of ignoring the express sentiments of customers. His paper is provided at Attachment 8.4.

The central question we put was:

> *What is the appropriate weight a regulator should give to transparent and direct consumer engagement in its decision making?*

46 See section 3 of Attachment 7.10 to our 2020 Plan.

47 CPP19, *Consumer Challenge Panel Submission to the AER on JGN's Regulatory Proposal*, 9 August 2019, page 34.

To answer this, Professor Graham's paper examines:

- Why increasing customer engagement in regulatory decision making is seen as best practice.
- The difficulties with the idea of a single consumer interest.
- Why there might be differences between consumer advocates and consumers.
- How the results of consumer engagement should be considered by a regulator.

The paper puts the problem into a regulatory context, considers the current customer evidence and argues that the AER should place more weight on the expressed views of consumers than those of consumer advocates and the CCP.

It relevantly observes that customer and customer advocate views can and do differ:[48]

> *It is critical to recognise that there may be a difference between the views of consumer advocates and the views of consumers. This possibility is mentioned by Locke, but rarely receives any discussion.*[49]
>
> *Within the UK, perhaps the most high-profile example of this revolves around pre-payment meters (PPMs) for energy supply. Most consumer advocates have been at best lukewarm and at worst hostile to these devices for two main reasons. First, the charge for supply via these devices is higher than a normal tariff, either standard variable or fixed. Secondly, there is a worry that PPMs conceal the extent of energy rationing through self-disconnection. In other words, rather than a consumer being disconnected for failure to pay a bill, which generates a statistic, if a consumer cannot afford to use energy, they will not charge their PPM, but this will not show up as a statistic and working out self-disconnection rates is very difficult. Whenever research is done into consumer experiences of PPMs, the message that comes back from consumers is that they are largely happy with the experience. Although they recognise the higher tariffs, they value the control over budgeting given by the PPMs.*[50]

When assessing our circumstances, it concludes that none of the conditions for the AER to ignore customers express views have been met. He concludes that: [51]

> - *Obtaining direct evidence of consumer views in a balanced and representative manner is a time-consuming and resource intensive exercise. Jemena has undertaken a process to understand consumer views on issues which has been widely praised and commended by the regulator and consumer bodies.*
> - *When dealing with expressed views of consumer preferences, there are few reasons for regulators rejecting them. This is especially the case when dealing with consumer views of their own preferences.*
> - *A regulator is justified in rejecting consumer views if they are of the opinion that the engagement was not objective or if they feel that the views are not representative of consumers. Neither argument applies here.*
> - *A regulator can reject consumer and stakeholder views if they are contrary to the legislation or to an expressed government policy that the regulator is bound to follow. This is not the case here.*
> - *Regulators may reject consumer views because they believe that they are wrong. There is a distinction to be drawn between consumer views about events or conditions which are external to*

48 Professor Cosmo Graham, *Regulatory decision making and consumer voices, December 2019*, page 10.

49 S Locke `Modelling the Consumer Interest' in G Bruce Doern and S Wilks (eds) *Changing Regulatory Institutions in Britain and North America* (1998) at 174. Cited in Professor Cosmo Graham, Regulatory decision making and consumer voices, December 2019.

50 Centre for Competition Policy *Fairness in Retail Energy markets?* 2018, at 50. Cited in Professor Cosmo Graham, Regulatory decision making and consumer voices, December 2019

51 Professor Cosmo Graham, *Regulatory decision making and consumer voices*, December 2019, page 3 and 4.

them and consumer views of their own subjective preferences. In the former case, regulators are required to take what they believe, on the basis of evidence, is the correct decision, regardless of consumer views. In the latter case, they should be very cautious about rejecting direct evidence of consumer views especially in a context where they are trying to encourage consumer engagement.

- *Rejecting express consumer views will have negative consequences: companies will have less incentive to take consumer engagement seriously and consumers will be less inclined to engage.*

We also note that the views expressed by a number of consumer advocates have a strong bias to short-term pricing outcomes over this action to address long-term interests. For example, CCP19 states:

> *CCP19 has concerns with the proposed accelerated depreciation. For a start it will increase costs to consumers in the short term, at a time when energy affordability is a major community issue and against the feedback from JGN's consumer engagement that affordability is key.*[52]

And the ECA's consultant states:

> *We do not believe this approach delivers on what we believe should be the primary objective of keeping gas prices as affordable as possible.*[53]

We recognise the importance of short-term affordability to our current customers whom we engaged with. Our proposal includes material price reductions for our current customers during the 2020-25 period. These reductions total $292 over five years for a typical coastal residential customer, and $459 over five years for a typical country residential customer.[54] Our proposal is for an immaterial reduction in these short-term bill savings (as set out in section 3.5), and so this proposal achieves both materially improved short-term affordability (assuming retailers pass in our reductions) and lower pricing in the future when customers will face other gas cost pressures.

We make two important observations about the short-term pricing bias in the views of consumer advocates.

Firstly, our standard asset life proposal is aimed at long-term affordability (and the proposal as a total package still addressing short term affordability), specifically in a climate where other parts of the gas supply chain will be increasing customer prices and competing electricity prices will likely continue to fall amid low marginal cost renewable energy and policy subsidies. This long-term view:

- Is what must govern the AER's decision making here in accordance with the NGO and this cannot be supplanted by the ECA's consultant asserting that there should be a new primary objective of short term pricing, and
- Reflects a proper application of the first depreciation criterion at rule 89(1)(a)[55] which is about support *growth* in services not lowering their cost to existing users.

Secondly, our customers understood that this standard asset life proposal was going to affect short term prices. This was acknowledged by the CCP19:

> *From the two sessions attended, CCP19 noted that participants appeared be aware of the inconsistency of their key desire for lower energy costs contrasted to their support for long term investment and accelerated depreciation (both of which increase their gas bills).*[56]

This shows they want action now for the long term.

---

52 CPP19, *Consumer Challenge Panel Submission to the AER on JGN's Regulatory Proposal*, 9 August 2019, page 33.

53 ECA, *Submission on JGN 2020-25 AA Proposal (attachment by TRAC partners)*, August 2019, slide 24.

54 A typical coastal residential customer consumes 15GJ per annum and a typical country residential customer consumes 35GJ per annum.

55 The depreciation schedule should be designed: (a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services.

56 CPP19, *Consumer Challenge Panel Submission to the AER on JGN's Regulatory Proposal*, 9 August 2019, page 33.

We question why the AER's draft decision rejects taking this action and favours a wait and see approach. Recent commentators have observed this behaviour and sought to explain it. For example, former Australian Treasury Secretary Dr Ken Henry recently wrote:

> *Humans have a tendency to overweight the short-term, heavily discounting, even ignoring, longer-term consequences. This behavioural bias is usually labelled 'myopia'. Humans are also prone to over-valuing costs relative to benefits, a behavioural bias labelled 'loss aversion'. Because of myopia and loss aversion, human decisions are frequently not rational.*
>
> *Governments are also prone to short-term decision-making, and overvaluing costs relative to benefits. But this can be rational for people elected for a parliamentary term of only a few years, directly accountable to myopic voters having to deal with the pressing day-to-day cost of living. Why would it make sense to expend energy, and political capital, dealing with a problem that is not even on the radar of the electorate, or which is considered unlikely to have a significant impact on the general quality of life for some decades to come?*[57]

We see clear analogy to the current decision before the AER in terms of the price setting task for the next five years and a benefit realisation period many years into the future. However, in this context the AER must recognise that:

1. For our proposal, the costs are necessarily NPV neutral; and
2. Adopting this proposal to support potential long-term benefit is the express wish of our customers.

[57] Dr Ken Henry, The political economy of climate change, posted on John Menadue – Pearls and Irritations, 9 December 2019.

3. Changing future asset lives is currently the best solution

In this section we present our Revised 2020 Plan, explain why this is both rule compliant and preferable to alternatives from the perspectives of rule compliance and customer impact, and we respond to stakeholder submissions.

3.1 What we are proposing

Our Revised 2020 Plan retains all elements of our initial 2020 Plan that were approved in the draft decision. It also seeks the following changes to standard asset lives for new investments.

Table 3–1: Revised 2020 Plan proposed changes to asset lives for new investments

Asset Class	Current standard lives (years)	Proposed standard lives for new investment (years)	Percentage of initial forecast capital expenditure in asset class compared to capital program as a whole
Trunks	80	50	0%
High pressure mains	80	50	14%
Medium pressure mains	50	30	16%
Medium pressure services	50	30	33%

The customer impact of this change based on our revised proposal is $2.10 per annum. That is, compared to a price reduction of 21.84% we are now proposing a reduction of 21.25%.[58]

3.2 Our proposal is Law and Rule compliant and preferable

Our proposal better supports the National Gas Objective than retaining the status quo would

As Incenta finds in section 4.2.1 of Attachment 8.3, our proposal supports both the efficient investment and efficient use elements of the NGO. It relevantly finds that:[59]

> *the capacity and incentive to invest is influenced by the extent that a service provider can expect to recover at least the efficient costs of supply and so earn a normal return on investment. Consequently, in circumstances where stranded asset risks are heightened, shortening the life of investments as proposed by JGN supports the recovery of cost, and so the motivation for continued investment when it is efficient.*
>
> *The NGO also includes a focus on efficient use and that, among other things, this be promoted for the long term interests of consumers with respect to price. As we explained in the previous chapter, one implication of a change in regulatory depreciation is to alter the time path of prices to customers, which in turn may affect the efficiency of use of the pipeline and the intergenerational equity of the pricing outcomes, and further that JGN's proposal is likely to:*
>
> - *enhance the efficiency of use of the JGN network, and*
> - *advance the intergenerational equity with which pipeline costs are recovered.*

58 These are the respective year 1 P0's, assuming the same x factors in years 2 to 5 as in our proposed price path, as set out in section 12.2 of our Revised 2020 Plan.

59 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, pages 26 and 27.

We also note that efficient use, and incentives for such use, must be assessed by looking at the delivered price of gas. This is the basis upon which customers make their gas usage decisions (i.e. their total price including the gas commodity, transmission, distribution, retail costs and where relevant gas appliance costs).

It is flawed to assess the question of gas consumers' efficient use by reference only to JGN's component element of the bill. Yet that is exactly what the AER's draft decision does. It states:

> *Under JGN's approach, today's customer would be paying more than necessary for reference services for many years before return of capital will reach a level where future consumers may start to benefit from that higher payment through relatively lower prices. We consider that it is unlikely that all customers would benefit from this higher payment over time. This is because some current customers may have stopped using the reference services before a lower price could apply to them. On the other hand, future customers would be paying a lower price for reference services as a result of the higher payment made by today's customers if we were to accept JGN's proposed shorter standard asset lives. This is unlikely to promote efficient use of reference services.*

We note that Incenta also concludes that efficient use should be assessed at a total cost of gas use level, stating:

> *an analysis of the efficiency of use of the pipeline network requires a consideration of all elements of the supply chain, as all elements in combination dictate how a customer uses the network.* [60]

Unsurprisingly, this is also how Core Energy's modelling of long-term gas demand scenarios assesses customer choices.[61]

Our proposal is more consistent with the Revenue and Pricing Principles than retaining the status quo

The AER is required to have regard to the NGL revenue and pricing principles when making its decision. It's draft decision states that it has done so, however this has not been shown at the level of each individual principle in the way our 2020 Plan had done.

Incenta has assessed our proposal against the relevant revenue and pricing principles and concludes as follows:[62]

- *A regulated network service provider should be provided "with a reasonable opportunity to recover at least the efficient costs" the operator incurs.*[63] *If an impending threat to future cost recovery exists, as has been put forward by JGN, and action is not taken within a sufficient period of time, this principle cannot be met. Action that seeks to align the recovery of costs with the economic life of assets is, however, consistent with this principle.*

- *A price or charge for the provision of services should allow "for a return commensurate with the regulatory and commercial risks involved".*[64] *If the regulatory approach does not permit that capital invested is returned to investors, it is clearly not possible for JGN to earn a return commensurate with the regulatory and commercial risks involved. This would also be true where the business is required to retain stranded asset risk but without explicit compensation being provided. The proposal from JGN is aimed at allowing it to recover efficient costs and so earn a normal return on investment.*

- *"Regard should be had to the economic costs and risks of the potential for under and over investment" by a regulated network service provider.*[65] *Returning capital invested to JGN earlier than otherwise does not mean that it earns a higher return; again, it is NPV neutral. Therefore, given the asymmetric consequences of not taking early action where stranded asset risk is a prospect, there is little reason to be concerned that returning capital earlier than otherwise would*

60 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 29.

61 Core Energy, *2019-2070 Scenario-based outlook for JGN gas demand*, January 2020.

62 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 27

63 Section 24(2) of the NGL.

64 Section 24(5) of the NGL.

65 Section 24(6) of the NGL.

> *lead to over-investment by a service provider. Further, as was discussed above, there is little reason to believe NSPs would have the incentive or capability to over-invest in the network purely due to capital being returned sooner than otherwise. Conversely, however, where businesses perceive there is a material risk of cost being unrecoverable, this is likely to have detrimental impact on the incentives for investment, and so a consequent risk of under-investment.'*

For the reasons we initially outlined in section 5.1 of Attachment 7.10 to our 2020 Plan, we fully concur with Incenta's views.

Our proposal is a preferable application of the depreciation criteria compared to the status quo and waiting for more information

The depreciation criteria must be applied to each access arrangement period on the best information available for that period. They explicitly provide for changes in the asset lives used to calculated regulatory depreciation over time, and do so for more reasons than just variation in the economic life of the assets.

Incenta has examined our proposal against the depreciation criteria. Below we set out each criterion along with Incenta's opinion on what is the intent of each, and how our proposal addresses each of the depreciation criteria.

Rule 89 (1)(a)

This rule states that the depreciation schedule should be designed:

> (a) *so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and*

Incenta states about this rule:[66]

> *A depreciation method that is directed to encourage a time path for reference tariffs that are consistent with the efficient growth in the market for services has two implications for the current matter.*
>
> *First, this criterion is guiding the regulator to use depreciation to target a time path for prices that are expected to result in an (allocatively) efficient pricing over time, and in particular, the efficient spreading of what we referred to as "residual costs" in section 3.4. As we noted in that section, an important role for regulatory depreciation is to ensure that what are essentially fixed costs are spread over time in a manner that encourages the efficient use of the pipeline (i.e., growth that is consistent with efficient use, or – if relevant – to ensure that "negative growth" is consistent with efficient use). As we concluded in section 3.4, we think there are good grounds to believe that the advancement of depreciation would improve the efficiency of use of the AGN JGN network:*
>
> - *Considering network costs alone – putting aside for now the implications of carbon abatement policies, the combination of the forecast decline in use per customer of natural gas, and the likely increase in the degree of price sensitivity of gas consumption in the future (i.e., as electricity becomes an increasingly competitive energy source for traditional gas uses), means that it is likely that allocative efficiency would be improved by bringing forward the recovery of capital. In addition, it was also noted that the best case for the continued use of the AGN JGN over the long term is that the distribution of hydrogen becomes efficient, but even in this case substantial network expenditure would be required to convert natural gas networks to hydrogen networks. Advancing the recovery of capital – and so creating scope for these additional costs to be absorbed – would be likely to advance further the efficiency of use of the gas network.*
>
> - *Considering the delivered product – we also noted in section 3.4 that an analysis of the efficiency of use of the pipeline network requires a consideration of all elements of the supply chain, as all elements in combination dictate how a customer uses the network. Further, we noted that (i) even putting aside carbon abatement measures, the price for natural gas is expected to continue increasing relative to the price of substitute energy forms, and (ii) as noted above, the best case*

[66] Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 29.

scenario for a gas distribution network in a carbon neutral economy is that distributed hydrogen proves to be commercial, but in that circumstance the cost of the commodity will be substantially greater than natural gas. As such, we explained that the efficiency of use of the gas network would be improved by advancing the recovery of network costs and so creating a greater scope to accommodate the projected future increase in the cost of the gas commodity.

Secondly, it can be observed that a key contributor to the efficient growth in the market for services is that the incentives exist for regulated businesses to make the investment that is necessary to support that growth. As we concluded in Chapter 3, absent some means of managing stranded asset risk the incentive for investment will be harmed, and so the prospect exists that the investment required to support the efficient growth in the market may not occur. This is particularly the case with respect to efficient expansions of the gas network for which the supplier may have more discretion over when (or indeed whether) to undertake these projects.

Rule 89(1)(b)

This rule states that the depreciation schedule should be designed:

(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

Incenta states about this rule:[67]

Rule 89(1)(b) provides that the depreciation schedule should be designed "so that each asset or group of assets is depreciated over the economic life of that asset or group of assets". The term "economic life" refers to the life that an asset is expected to remain in service, which may differ to the asset's technical life if the useful life for the asset is expected to be curtailed earlier as a consequence of technological change (i.e., it becomes efficient to replace the asset at an earlier time because a superior technology exists) or the market served by the asset is expected to cease prior to the asset reaching the end of its technical life. Thus, this rule requires a holistic assessment of the factors that are likely to affect an asset's useful life.

We observe that the useful life for an asset can never be known with certainty because it will be dictated by factors that are inherently unknowable (like the rate of technological change and changes to government policy), and so the best that can be arrived at are scenarios for the economic life and possible views on the likelihood of each. This raises the question of what should be applied as the economic life – should it be some form of expected (i.e., probability weighted) value for the economic life, or some other value? As we have explained earlier, an important outcome for the regime – which is promoted by the National Gas Objective and Revenue and Pricing Principles – is that incentives are provided for efficient investment, which in turn requires stranded asset risk either to be compensated or removed. As the regime does not include compensation for this risk, it necessarily follows that preservation of investment incentives requires the risk to be removed. This, in turn, would dictate that the economic life applied should reflect the minimum life over which there is substantial confidence (or, stated alternatively, no material risk) that the asset will remain in useful service, given the information available at that point in time.

If, as has been put forward by JGN, there is a material risk that the economic life of the assets will be shorter than their technical lives, imposing shorter asset lives for regulatory depreciation is justified and permitted by the Rules.

Rule 89 (1)(c)

This rule states that the depreciation schedule should be designed:

67 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 30

(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

Incenta states about this rule:[68]

In Chapter 3, we observed that it is appropriate to refine the depreciation settings over time as new information becomes available. As a consequence, we remarked that JGN's proposal should be viewed as a proposal to change the economic lives for capital expenditure that is undertaken during the next access arrangement period that is applicable only for the next access arrangement period, and with the option to reassess the economic lives for these assets – and for capital expenditure that is undertaken in future periods – in future access arrangement periods as new information becomes available. The effect of Rule 89(1)(c) is to dictate that this refinement of lives over time should be undertaken.

Turning to JGN's proposal, this rule provides a firm basis for assuming that where new information reveals that a longer economic life may be realistic (for example, because the prospects for hydrogen become more certain), adjustments will be made to the asset lives for any investments made within the 2020-25 period as well as those undertaken in future periods. This flexibility, in turn, should encourage early action in the face of future uncertainty to avoid a position whereby assets may be stranded and so preserving the incentive to invest, as JGN has proposed. [69]

Rule 89 (1)(d)

This rule states that the depreciation schedule should be designed:

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (i.e. that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and

Incenta states about this rule: [70]

The main purpose of this rule is as a check on the integrity of the depreciation calculations, and to reinforce that a key feature of the gas regulatory regime precludes revaluations of assets that are not properly taken into account when deriving the revenue requirement.

JGN's proposed changes to the lives of certain assets meet the requirements of this rule.

Rule 89 (1)(e)

This rule states that the depreciation schedule should be designed:

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

Incenta states about this rule: [71]

This rule envisages the use of depreciation as a tool to address the cash flow needs of a regulated business.

JGN's application does not rely upon this clause to justify its proposal.

---

68 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 31

69 Ibid, page 31

70 Ibid, page 31

71 Ibid, page 31

3.3 Acting now supports efficient investment incentives

Why make this change now and not in five years?

The purpose of this proposal is to ensure JGN retains the right investment incentives during the next five years. This simply cannot be achieved if we defer the decision. The fact that with further information in future the asset lives can be revisited dynamically and that the change is NPV neutral with no change in cost to customers, means this is the only viable option for achieving the efficient incentives.

If in future more information proves that the efficient rule and depreciation criteria solution is to then apply the shorter lives to some or all of the existing asset classes (i.e. to residual asset lives), the pricing impact on customers will be higher. This outcome would be a less preferable version of depreciation criterion a than our current proposal.

3.4 Acting now aligns with good regulatory practice and precedent

Acting now is consistent with good regulatory practice

This issue is not novel in economic regulation. Regulators have faced asset stranding risk in many situations and the literature supports acting now rather than waiting. The joint AER and ACCC working paper series acknowledged this in its review of the most important literature in the field, with Darryl Biggar writing: [72]

> *In essence, when the regulated firm will be constrained by other forces in how much it can recover in the future, the regulator must take this into account in the present, and allow the firm a higher rate of depreciation. This is the origin of the tilted annuity concept used by some regulatory authorities in telecommunications regulation. Crew and Kleindorfer point out that traditionally there has always been a sense among regulators and utilities that problems could be put right "at the next rate case". However, they emphasise that this is clearly not always true. If some other constraint – such as changes in demand or technology – prevents the regulated firm from earning a normal return in the future, the regulator must take that into account in its depreciation policy today.*

This change also aligns with regulatory precedents for equivalent risks

When Incenta reviewed precedents across Australia, New Zealand and the United Kingdom it found: [73]

> *a pre-disposition among regulators taking early action on managing stranded assets given the asymmetric consequences of inaction.*

Section 5 of Attachment 8.3 examines examples from gas pipelines, fibreoptic cable networks, and electricity networks. These all adopt depreciation as the preferred regulatory lever for managing this risk.

3.5 Acting now supports an immaterial impact to current customers

Making this standard asset life change now is a measured step with less impact than alternatives, and no greater than that of equivalent future-proofing revenue impacts for approved energy innovation expenditure in electricity distribution networks. In this regard we note that:

- In isolation, current customers will only pay $2.10 per annum more over the five years with the proposed standard lives compared to retaining the current standard lives:
  - However this increase is already included within the proposed savings of $292 over five years for residential customers.

---

72 Darryl Biggar, *The fifty most important papers in the economics of regulation | ACCC/AER working paper series - Working Paper No.* 3, May 2011, page 21.

73 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 32.

  - This price impact would drop to $1.29 per annum if standard lives were more aligned to electricity networks, for example capped at 40 years.

- AER allowances for other 'future proofing' schemes already applied for years in electricity (for example DMIA) include costs per customer in the order of $0.55 to $1.43 ($2018-19) per annum. While feed-in tariffs cost well in excess of $100 ($2018-19) per customer per annum in some jurisdictions.[74]

- The closing RAB at the end of 2024-25 only reduces by $16M or 0.4% if the proposed standard lives are adopted and therefore do not have a material impact on regulated revenues and therefore distribution customer bill impacts.

3.6 Alternative solutions are more costly to us and our customers

We have considered various alternatives, and none were considered preferable.

A common theme is our engagement discussions with consumer advocates and in the AER' draft decision, is the question of whether there are other preferable alternatives. Box 3.1 explains what consumer advocates said at our October forum, and the AER's draft decision stated: [75]

> *Rather than accelerating depreciation on new assets, providing service providers with incentives/funding to extend the lives of existing assets, instead of building new assets, may be preferable. Other alternatives, such as requiring greater upfront connection costs for augmentation, could also be a better solution for specific areas of concern rather than a change to a depreciation approach that affects all new assets and customers in the same way.*

> **Box 3.1 Things to address from the October 2019 stakeholder forum report**
>
> … Advocates remained concerned that accelerating depreciation meant transferring the risk to consumers who did not necessarily have the resources to manage it. Advocates were keen for Jemena to reprosecute the case for why asset depreciation was in the long-term interests of customers.
>
> … Advocates would like Jemena to explore alternatives to accelerated depreciation that could have a lower customer impact.
>
> … Questions remained on whether the increased contribution to customer bills caused by accelerated recovery, could stymie demand for gas.

In our pre-lodgement engagement program and in response to the draft decision, we have carefully considered how we should best support efficient future utilisation of gas and mitigate the risk and incentive consequences of us expecting not to be able to fully recover our investments.

When considering the options that were available to us, we have been guided by commercial options, what is permitted within the regulatory framework, and by the feedback that we received from our customers throughout our customer engagement program. In particular, we have considered the impacts in the context of the four key themes which arose throughout the course of our engagement, namely: affordability, a safe and reliable gas service, fairness and the future.

We presented our alternative options assessment in our 2020 Plan. This assessment is set out in Table 3–2 and has been updated for new information where available. We have also considered a new option, which is to adopt the UK approach which caps asset lives at 40 years, and is also consistent with electricity network asset lives. This option is also presented in Table 3–2.

74 Estimated by JGN based on electricity distribution businesses' RIN responses covering 2015-16 to 2018-19.

75 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 46.

Table 3–2: Options considered

Option	Comment	Outcome	Consistent with customer feedback
Compensating asset recovery risk via rate of return	The binding rate of return instrument does not account for asset stranding risk. The AER has been very clear when addressing the cost of capital for the regulated energy networks that the regulatory WACC should not – and so, as estimated, does not – seek to compensate for potential stranded asset risk.	N/A	N/A
Reduce service levels (to reduce forecast capex)	Only $2.8M of the capex program has a key driver of maintaining service levels.	This option would result in minor reduction in capex but would adversely impact JGN's reputation with its customers. It would have an immaterial impact on reducing stranding risk	This option is inconsistent with customer feedback - our customers told us that they want us to maintain existing service levels.
Scale back marketing/growth opportunities	We have an obligation under the NGR to provide potential customers with an offer to connect to our network – we have limited control over how many customers we connect. Our marketing program is based on increasing utilisation of our network – increasing/maintaining load.	Scaling back marketing would only marginally reduce opex but would lower demand. This would increase prices for all JGN customers.	Our customers told us that it is sensible for us to seek ways to ensure that the network remains utilised. If we were to scale back investment in growing our network, this would lead to higher prices.
Accelerate depreciation of all assets (i.e. lower remaining asset lives and standard asset lives)	We have adopted a measured approach and are only proposing to change the asset lives of certain new assets. This means that we will continue to bear the risk that we will not recover the full costs of investments made before 30 June 2020 and also bear the risk of investments made during 2020-25 right out to 2075. We believe that this approach strikes a fair balance between the impacts on our existing and future customers, and is consistent with feedback we received on the key theme of fairness. This is the approach adopted by IPART in its draft decision for Railcorp's Hunter Valley Coal Network sectors.	Significant price increases	Recognising that affordability is a key issue for our customers, we did not test this option. We note however that in future this option may be a necessary requirement, and failure to act now would exacerbate the impacts of future action on customer bills.

Option	Comment	Outcome	Consistent with customer feedback
Increasing customer contributions by introducing a charge for standard connections	Our research (explained in section 4.5) indicates that introducing a charge for standard connections would influence some potential customers not to connect to gas (a $300 charge would result in around 23% of potential customers choosing not to connect). This would actually increase bills over the long term. This does not impact non-standard connections, where contributions are payable if Rule 119M is satisfied.	Reduction in net capex but likely to increase prices for all customers if electricity to gas customers choose not to connect. This would reduce the cost-competitiveness of gas.	Our customers were supportive of a charge assuming that it lowered prices for all customers.
Innovation to prove and ready the network for a low carbon alternative gas	We are investing in a hydrogen trial with the aim of showing that hydrogen can be used within our network. Note, even if the trial is successful, transitioning our network to enable the distribution of low carbon gas will only be possible if hydrogen can be competitively produced and delivered to our network.	We are including this expenditure as speculative capex.	Our customers want us to work towards a renewable future.
Charge network exit fees where customers disconnect early	If the life of a customer connection becomes insufficient at the prevailing tariff to pay-off the assets built and used to service them, a disconnection fee equivalent to a contract exit fee may be appropriate to protect the interests of remaining customers and JGN. This would require amendment to our connection and use of system agreements, and its introduction may impede our marketing of natural gas.	Exit fees would be treated as a capital contribution and deducted from the RAB.	While this may support the fairness and future sustainability outcomes, it is unlikely to be implementable within the next five years given the contractual changes that may be needed to apply it.
Cap asset lives for new investments to 40 years	This option adopts the approach that is applied in the UK, which caps asset lives at 40 years, and is consistent with electricity network asset lives, but would only apply to new investments.	This option would increase the distribution portion of customer bills by $1.29 per annum relative to retaining the current period asset lives.	While we did not test this option with customers, it would have a lower bill impact than our current proposal, and would go some way to responding to their feedback on the key theme of fairness, in relation to long term bill impacts.

Incenta also examined alternatives and concluded: [76]

> *There is substantial regulatory precedent for using depreciation to remove stranded asset risk to the extent that this is possible. There are good arguments to support this – compared to the main alternative tool of compensating for the risk, advancing depreciation has the advantage of not creating the prospect of creating windfall gains or losses. Moreover, depreciation is also flexible as asset lives can be adjusted periodically in light of the arrival of new information. The other possible measures are either ineffective for managing stranded asset risk (higher fixed charges), likely to deter new customers and create perceptions of unfairness (higher capital contributions), create perceptions of unfairness, or be anticompetitive and unworkable (exit fees).*

3.7 Responses to stakeholder submissions

Two consumer advocates made submissions to the AER on our 2020 Plan (PIAC and ECA) in addition to the submission of CCP19. These consumer advocates, in contrast to our customers, did not support our proposal. Likewise, retailers Origin, AGL and Energy Australia also did not support our proposal. Submissions were received from Energy Networks Australia (**ENA**) and AusNet Services which did support our proposal.

Table 3–3 sets out the matters raised and our response.

Table 3–3: Summary of submissions on our 2020 Plan

Feedback	Our response
Public Utility Advocacy Centre (PIAC) PIAC reiterated its view (from its response to our Draft 2020 Plan) that our proposal represented a transfer of risk between consumers in the short-term and us in the long-term. It stated: '*While PIAC is generally supportive of the analysis Jemena has done in arriving at its proposal and the engagement it has conducted to minimise negative impacts on consumers we suggest that doing the "least bad" version of accelerated depreciation doesn't necessarily make it good.*' PIAC submitted that the issue should be considered at a policy-level of regulated businesses in general and not limited to us.	Our proposal does not remove JGN's asset stranding risk. Industry-wide removal of asset stranding risk would require that the relevant provisions that allow for this (e.g. NGR 77(2)(e) and 85) be removed to place gas on an equivalent rule footing to electricity networks (given we receive the same WACC under the AER's binding instrument). An industry-wide consultation would be warranted for such a regulatory change (as would occur anyway given it would require a rule change through the AEMC). Our proposal seeks to address investment incentives over the next five years only. It is not a risk transfer and by no means removes the asset stranding risk that JGN still bears. As shown in Table 2–2, this proposal merely lessens the asset risk we face between 2055 and 2075, and removes the expectation that the assets we invest in now will be recovered out to 2105.
Energy Consumers Australia (ECA) ECA submitted that: 1. They had not seen any compelling evidence to support the proposed initiative 2. It was not clear how Jemena assessed the risks of uncertainty against the future opportunities for benefits. 3. A national strategy about asset-stranding should be investigated to ensure that risks were not passed through inappropriately to consumers 4. Changing asset lives was contrary to the long-term interests of consumers because the increase	We respond to each of these items individually throughout this attachment which we summarised as follows: 1. The adequacy of the evidence must be assessed by considering: a) the purpose (i.e. to set the right investment incentives for the next 5 years) which cannot be achieved if we defer the decision; b) the fact that with further information in future the asset lives can be revisited dynamically; and c) the change is NPV neutral with no change in total cost to customers. 2. The regulatory regime does not permit JGN to capture future benefits (i.e. returns are capped at the WACC). Because the WACC does not compensate for the stranding

76 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, page 5.

Feedback	Our response
in prices today will further disincentivise the use of gas as an energy source. ECA's consultants (TRAC Partners): 5. Placed their primary emphasis on ensuring that gas is affordable as possible in the short-term 6. Felt delaying the decision will allow further clarity around the Hydrogen Strategy and the market response to the supply from the LNG import terminal at Port Kembla 7. Also saw the proposal as re-allocating risk from JGN to our customers.	risk, the problem is an asymmetric one being driven by the way the draft decision applies the regulatory regime. 3. Our proposal does not remove JGN's asset stranding risk. 4. The increase short-term is likely to be imperceptible amid the overall price reductions that our customers will benefit from in 2020-25. 5. In addition to being imperceptible in the short term, section 4.7 explains how our proposal supports efficient growth in the market for reference services which is the relevant rule consideration for the AER's decision making. 6. Sections 2.1.2 and 0 explain how the Hydrogen strategy does not remove the risk our proposal seeks to address and clarifies that hydrogen is a long-way from cost competitive. The NSW Business Chamber submission discussed in section 4.4 shows that the Port Kembla terminal need immediate action to avert NSW gas shortage by 2025. 7. Our proposal does not remove JGN's asset stranding risk.
Consumer Challenge Panel (CCP) CCP19 were concerned with the increase in costs in the short-term. They also said that the proposal appeared inconsistent with Jemena's confidence in the future with its plan to build excess capacity. They felt that the issue could be better approached in the future, probably in about ten years. CCP was the only submission which had reservations about Jemena's engagement approach to this issue. They raised the question of whether alternative options ought to have been offered to consumers in terms of payback times. They also felt that, with such a complex issue and the level of information given, consumers might have erred on the side of fairness in a discussion.	The adequacy of the evidence must be assessed by considering: a) the purpose (i.e. to set the right investment incentives for the next 5 years), which cannot be achieved if we defer the decision; b) the fact that with further information in future the asset lives can be revisited dynamically; and c) the change is NPV neutral with no change in cost to customers. We explain the basis of our customer engagement information and scenarios in section 4.8 and in our response to the AER's information request number 38. Professor Graham addresses the issue of customers 'erring on the side of fairness' and how this is not irrational nor inconsistent with other research, and thus no reason to dismiss their views.
Retailers AGL, Energy Australia and Origin did not support our proposal. Origin submitted: 'It is clear there are differing views on the future of the gas sector in the face of decarbonisation, both pessimistic and optimistic. At this stage it is not clear that the proposed asset classes will necessarily become redundant before the end of their technical lives as suggested by JGN. Accordingly, Origin consider it prudent to defer any decision to alter asset lives at least until such time as there is more clarity with respect to the role of gas networks in a decarbonised environment.'	These differing views and the material risk we face if the pessimistic case transpires (e.g. if the NSW government adopts equivalent policies to the ACT government) are exactly what drives our expectations about whether we will earn a normal return and therefore our investment incentives. It is these expectations and incentives that our proposal seeks to address. Our expectations cannot be retrospectively fixed, so deferring this issue to the next AA review simply doesn't work.

4. We have addressed the AER's concerns and identified a number of inconsistencies in its reasoning

In this section we respond to each of the considerations raised in the AER's draft decision as a contributing reason for its rejection of our proposal. We note that unlike other elements of its draft decision, the AER's draft decision on this proposal does not set out what further information it would require to approve our proposal.

4.1 The evidence threshold

Firstly, before we discuss each of the AER's specific considerations, we must address the draft decision's overarching conclusion on a lack of evidence. It states that there was insufficient evidence to change these standard asset lives and that it (and some consumer representative) would therefore prefer to wait for a later AA review when more evidence is available.

The AER draft decision states: [77]

> *We have considered the issues raised by JGN that may affect the economic lives of its pipeline assets, including the forecast short term declining gas usage trend, the Australian Energy Market Operator's (AEMO) forecast gas supply shortfall, and the NSW Government's planned 2050 carbon neutral target. We do not consider there is sufficient evidence to conclude that these issues will result in the utilisation of JGN's network significantly declining. In our view, the assumption that these issues have reduced the expected economic life of JGN's assets is speculative at this point in time and has not been adequately established by evidence-based forecasts.*

These statements appear to misunderstand what the task before the AER is and what the resulting evidence threshold should be.

The task here is to adopt standard asset lives that provide us with the correct investment incentive as we spend capex during the 2020-25 period. The AER's decision must ensure we have a reasonable expectation of recovering our costs and a normal return during that period. It is the factors that would reasonably inform our expectations that establish the correct evidentiary threshold here.

The evidence threshold is also affected by the inherent flexibility that rule 89(1)(c) provides to dynamically adjust the asset lives for the best information available at each AA review.

Incenta has reviewed the AER's draft decision in this regard and concluded: [78]

> *In our view, the AER has approached the question of whether the quality of evidence on stranding is sufficient in the reverse to what the gas Rules, revenue and pricing principles and National Gas Objective require.*
>
> *A common and central implication of these instruments is that investors should expect to recover efficient cost. A clear outcome of the current regime – and one that the AER has accepted – is that stranded asset risk is not compensated via the regime. Thus, to the extent that there is a reasonable basis for believing that stranded asset risk is more than immaterial,[79] then action is required to remove the risk, otherwise the prospect exists that efficient investment will be dissuaded and the long term interests of customers will be eroded. We further observe that a commitment to look again at the issue in the future is not a sufficient response because:*
>
> - *investors are likely to perceive as "hollow" a commitment by the regulator to review regulatory settings in the future after irreversible investments have been undertaken – encouraging efficient*

[77] AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 15.

[78] Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, pages 3 and 4.

[79] To be clear, stranded asset risk requires there to be uncertainty (risk) as to whether asset costs will be fully recoverable under current regulatory settings, it does not require certainty that costs will not be recoverable.

investment requires the regulatory settings to be appropriate at the time the investment is being considered,

- *by deferring decisions about whether to mitigate asset stranding risk, then a larger response would be required to mitigate the risk and further that it is too late – given competition from alternative fuels – to act and asset stranding results.*

Further, the adjustment that JGN has proposed is the minimum required to ensure there is an incentive for investment during the next access arrangement period. JGN does not propose adjustments to the lives of past expenditures, and the ability exists to review the lives of the subject capital expenditures and those in future access arrangement periods in the next and subsequent periods as new information arrives (indeed, the gas Rules encourage a dynamic review of asset lives). Thus, there is little downside to acting early, but a potentially material upside.

Moreover, even if the onus was on JGN to prove that there is stranded asset risk, it is difficult to believe that an objective observer could conclude that there was not a non-immaterial risk of asset stranding from the material presented and that is easily available.

4.2 Decarbonisation

The AER draft decision states: [80]

We acknowledge the NSW Government's planned net-zero carbon objective. However, we note that it has not yet been legislated. We consider this objective, by itself, is not sufficient evidence that the economic lives of the pipeline assets will be significantly shorter than their technical lives. …

Therefore, we do not consider that the NSW Government's net-zero carbon objective alone is sufficient evidence that JGN's pipeline assets will not be used beyond 2050.

And: [81]

There is significant uncertainty around the NSW Government's policies on decarbonisation, and their potential impact on JGN's network utilisation. We are not aware of any policies that would have a direct negative impact on JGN's network utilisation.

Firstly, JGN does not submit that its assets 'will not be used' after 2050. Instead, we consider (as do most energy commentators) that they will be used to a lesser extent and face pricing pressure elsewhere in the gas supply chain. In this context we seek to adjust the profile of our depreciation recovery to support growth in the market for gas services in the future as Rule 89(1)(a) specifically provides for.

As Professor Cosmo so eloquently puts it: [82]

There is no argument about decarbonisation policies having an impact. The debate is about the timing of the impact or about mitigating the impact, for example, through the development of hydrogen as a substitute for natural gas

As we have explained in section 2.1.1, the NSW government's relevant policies have been confirmed since our initial proposal. We also observe that our risk and incentives are not solely affected by whether government has yet legislated for decarbonisation, particularly on investments with economic lives of 30-50 years.

One policy that will have a direct negative impact on our assets' economic lives is the NSW government's agreement to the COAG hydrogen strategy action 3.15, whereby it has '*Agree[d] to not support the blending of*

80 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 22.

81 Ibid, page 23.

82 Professor Cosmo Graham, *Regulatory decision making and consumer voices*, December 2019, page 3.

hydrogen in existing gas transmission networks until such time as further evidence emerges that hydrogen embrittlement issues can be safely addressed.'[83]

4.3 Development of hydrogen

The AER draft decision states: [84]

> *We consider the factors raised by JGN, stakeholders, and those highlighted in our review of industry research above indicate there is a positive, albeit uncertain, outlook for the impact of hydrogen on JGN's network. Therefore, we consider an assessment of changing the economic life of pipeline assets is better supported at a later stage when there is greater certainty about the feasibility of hydrogen gas.*

JGN supports the important role that Hydrogen *could* play in decarbonising our economy. However, for the reasons we explain in section 2.1, we cannot bank the ability for it to keep gas cost competitive and attractive to our customers out to the year 2105 which is what it would need to do to sustain the existing standard asset life used on our steel trunks and high pressure mains.

The best information we currently have (including as published with the national Hydrogen Strategy and in the investigation that GPA Engineering conducted on our network's readiness to host hydrogen – see Attachment 8.5) must be used to establish the best estimate in our current circumstances to apply for the 2020-25 AA period. That information tells us that:

1. Hydrogen is known to cause embrittlement in steel pipelines[85]
2. Because of this, COAG does not currently support its use in transmission assets, due to these being made of steel (like JGN's trunks and HP mains), and
3. Even the AER considers that '*The integration of hydrogen as a fuel requires rule and law changes*' and the AER reading of the NGL definition of natural gas is that it precludes hydrogen.[86]

GPA's review of our network concluded that: [87]

> *The majority of the network is suitable for hydrogen, however, a significant amount of further work and capital investment is required to make the network hydrogen compatible.*
>
> - *A network capacity assessment is required to ensure gas supply to current and future users remains reliable. Where capacity constraints are identified, expansion of existing capacity will be required, which would involve significant capital investment.*
> - *Integrity and durability reviews of existing piping, components and equipment is required to ensure they are compatible. For incompatible items, upgrading or replacement would be required, which would involve significant capital investment.*
> - *Review of all existing Jemena safety systems and operating procedures including (but not limited to) SCADA, SAOPs, emergency response plans, blend and network control philosophy, and maintenance guidelines would be necessary. Where inadequacies are identified revision, change management, communication and re-training would be required.*

[83] COAG Energy Council, *Australia's National Hydrogen Strategy*, November 2019, page 80.

[84] AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 23.

[85] GPA, *Hydrogen in the Gas Distribution Networks*, 2019, page 40-43.

[86] AER, *Attachment 5: Capital expenditure | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 5-71.

[87] GPA, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page 20.

The AER draft decision also states:

> *A report by Deloitte Access Economics on behalf of the ENA indicated that hydrogen production via electrolysis will be cost competitive with decarbonised electricity (including network costs) by 2050.*

We note that:

- This work was prepared back in 2017 and more current information on the forecast pathway for hydrogen cost competitiveness published with COAG's National Hydrogen Strategy (provided at Figure 2.1 above) has not reached the same conclusion. Likewise Figure 2.2 shows that current expert forecasts of hydrogen cost presented in Core Energy's 2019-2070 Scenario-based outlook for JGN gas demand (see Attachment 8.6) show that only one of these forecasts (Core Energy's fast learning scenario) gets to the hydrogen price needed for competitiveness in gas blending by 2050.
- 1.4 million of our 1.435 million customers are residential households. Households change over their gas appliances approximately every seven years. Even if the Deloitte forecast of cost competitiveness by 2050 did eventuate, the damage to the gas market by then will likely have already manifested and thereby shortened the economic life of our assets.
- It is not just sufficient for the hydrogen commodity price to be competitive. Our network costs and customers' conversion costs will also affect the extent to which hydrogen becomes viable. GPA's observed that: [88]

  > *100% hydrogen conversion studies completed in the UK indicated that replacement and upgrades to the distribution network and gas appliances would be required, resulting in significant financial impacts. The H21 project in Leeds (UK) estimated that the average cost of conversion per connection, including gas network and appliance upgrades was £4,028 ($7,708 AUD).*

- Our Western Sydney Green Gas trial is limited to testing the injection of hydrogen in our gas networks to build operational capability and assess the impact a blended gas stream will have on operational management, asset integrity and customer metering and billing. It does not in any way seek to assess the technical and safety feasibility to deliver 100% hydrogen across all parts of the network with different pipeline material, a risk that has been recognised in the National Hydrogen Strategy (see section 2.1.2 above) and which GPA Engineering considers there is clearly a lot more detailed work to be done to prove (see Attachment 8.5).

4.4 Gas supply and demand

The AER draft decision states:

> *AEMO data suggested that through until 2038, there is stable NSW commercial and residential gas demand under all forecasting scenarios. AEMO has also forecast a supply shortfall by 2030. However, there is a significant level of domestic gas production, an Australian Domestic Gas Security Mechanism and several interstate transmission pipelines commissioned, including the Northern Gas Pipeline (run and operated by Jemena). These indicate that network utilisation is less likely to be significantly impacted over the short to medium term.* [89]

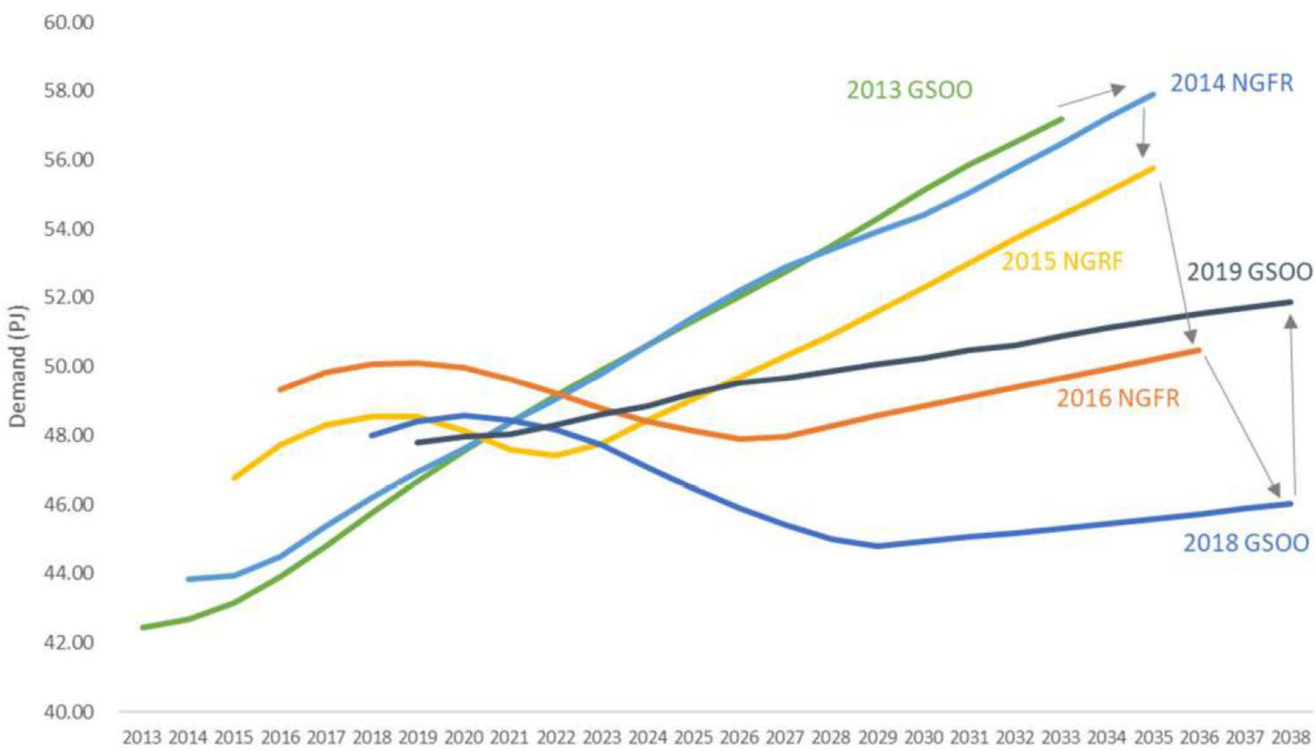
We note that it is important to recognise that the AEMO 2019 GSOO forecast is just one of many current forecasts, and that it represents a forecast at a point in time. Indeed, the fact that AEMO has a range of forecasts serves to highlight the uncertainty surrounding future demand. Further, we also note the significant variability in AEMO's forecasts year on year. Figure 4.1 shows that annually when AEMO has updated its forecast, each time (with the exception of GSOO2019) it has lowered its gas demand forecast.

---

[88] GPA, *Jemena NSW Gas Distribution Network Hydrogen Future Study*, December 2019, page ii.

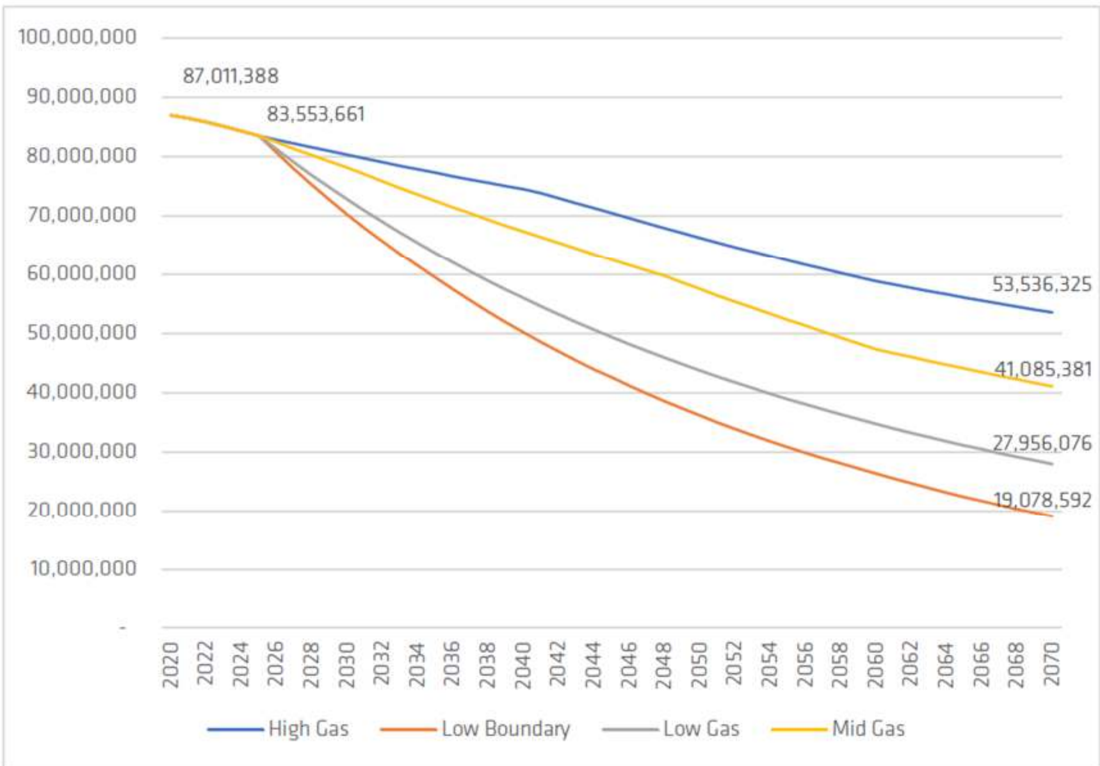
[89] AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 46

Figure 4.1: Comparison of AEMO forecasts over time (residential and commercial)



We commissioned Core Energy to prepare a long-term NSW gas demand forecast based on current information as at December 2019. Core Energy's scenario forecasts for total JGN demand out to 2070 are shown in Figure 4.2. This illustrate four scenarios as explained in Box 4.1. Attachment 8.6 provides a breakdown of the component scenario forecasts for total residential, small business and Tariff D (commercial) demand.

Figure 4.2: Total JGN demand scenarios (total GJ per year)



Source: Core Energy

Box 4.1 Core Energy scenarios

Low Boundary

- Gas demand consistent with GAAR 20-25
- 2050 net zero target achieved via complete electrification: bans on new gas connections, policy changes such as subsidies to remove gas appliances, rebates on electricity appliances (like announced in the ACT), hydrogen/biomethane not competitive, lower utilisation increases network charges. Cost of batteries, solar etc continue to fall.
- NSW Government mandates progressively move toward no new connections under an emission reductions target from 2035 onwards; gas appliances progressively phased out
- 1.8% average reduction in Tariff D due to energy substitution and industry rationalisation/international competition

Low Gas

- Gas demand consistent with GAAR 20-25
- Net zero target achieved: blend of hydrogen and biogas no conventional natural gas. Higher cost of gas, customer retention only where it is not cost effective to electrify (apartment buildings with sunk infrastructure or specific industrial customers). Lower new connections from 2035. Some demand loss from existing customers where they can easily switch - i.e. when renovating.
- NSW Government mandates progressive move toward no new gas connection from 2035 (per above)
- 1.7% average reduction in Tariff D

Mid Gas

- Net-zero target achieved: natural gas, biomethane and hydrogen. Possibly offsets for natural gas or cost effective biomethane and hydrogen. Gas price higher than current levels. Potential for decarbonisation pathway in the longer term. Gas still competitive due to higher substitution cost of electrification. Not losing demand but limited new connections from 2035.
- 1.4% average reduction in Tariff D

High Gas

- Net-zero target achieved: Technological breakthrough makes renewable gas cost competitive. Continued gas connections. No decline in usage.
- Residential and small business lower than average recent trend
- 1.3% average reduction in Tariff D

As demonstrated by the Core Energy scenarios in Attachment 8.6, the AEMO forecasts do not appear to explicitly model the effect of significant, increasing, and evolving electrification incentives, or any other step changes in the gas demand, such as the effect on consumer behaviour of accelerating NSW net-zero carbon targets – AEMO seem to rely on historical inputs as a predictor of the future, without sufficient account taken of prospective "step-changes".

On the contrary, the concerns raised by JGN and EnergyQuest (discussed below) caution against "business-as-usual" projection. Respectfully, we consider the matter is not about which forecast is correct, but the significant risk and uncertainty in all forecasts that favours a bias to action.

Our customers are deeply concerned about the supply shortfall AEMO has forecast

The draft decision's commentary on AEMO's forecast gas shortfall also understates just how concerned NSW stakeholders are about both the availability and price of gas over the next ten years. In December 2019, the NSW Business Chamber published a report prepared by EnergyQuest titled 'Running on empty: How to keep NSW fuelled for the future'.

EnergyQuest observes that AEMO has warned that gas supply in NSW will not meet demand in the winter of 2025 and that prices have already risen in response to the supply tightening.[90] AEMO's GSOO recommends that this shortfall must be responded to soon, given the lead times, through:

- *Exploration and development of new southern resources, or*
- *New gas supplies delivered via LNG import terminal(s), or*
- *Major pipeline infrastructure expansions to deliver Queensland and Northern Territory gas southwards, or*
- *A combination of all three.*[91]

In contrast, EnergyQuest recommends immediate action on all these fronts to sure up supply to NSW which relies on gas imports from other states for practically all its natural gas (98%). It sets out four key recommendations for immediate action in order to avert shortfalls in 2025. These recommendations and their implications for the AER's decision on JGN's proposal are set out below.

Table 4–1: Business chamber and Energy Quest recommendations and their implications

Recommendation	EnergyQuest's concern	Implications for the AER's consideration of JGN's proposal
1: Approve development of the Narrabri gas field by 2020	Due to the time needed to bring the field fully online, for Narrabri to be producing by the time of the expected supply shortfalls in 2025, approval to proceed needs to be given by 2020.	If these approvals are not imminent at the time of making its decision, the AER cannot presume that NSW won't face gas shortfalls that will affect JGN's market demand and asset lives after 2025.
2: Begin a program of pipeline and infrastructure upgrades to expand capacity by 2021	Gas pipeline infrastructure needs to reflect the new balance of supply sources. A review of gas pipeline infrastructure should be carried out, to identify constraints and viable capacity upgrades for links between NSW and northern producers. Pipeline capacity may also need to be expanded between proposed LNG import facilities and the major demand markets within NSW.	The AER must be realistic about the likelihood of transmission pipeline infrastructure investment happening in a timely way to mitigate supply shortfalls, particularly given the investment incentive effects of the recent gas market reforms for the non-scheme pipelines that service NSW and the current COAG gas reform consultation Regulatory Impact Statement[92] which is contemplating removing the current provisions for access holidays on new pipelines and mandating incremental pricing for pipeline expansions.
3: Facilitate LNG import terminal construction for NSW to begin by 2022	The NSW Government should support LNG imports into NSW, and ensure that permits and applications for expansion are prioritised. To be able to contribute to improved security at the time of the projected 2025 shortfalls, LNG facility developers should be in a position to start construction by the end of 2022.	This timeline is unlikely to be realised based on past NSW Government approvals precedent. For example, prospective developers of gas in NSW have faced protracted timetables for government approvals. The NSW Government designated the Narrabri Gas Project as a 'Strategic

[90] EnergyQuest, *Running on empty: How to keep NSW fuelled for the future*, December 2019, page 4.

[91] AEMO, *2019 Gas Statement of Opportunities*, March 2019

[92] COAG, *Options to improve gas pipeline regulation | COAG Regulation Impact Statement for consultation*, October 2019, page 126-127.

Recommendation	EnergyQuest's concern	Implications for the AER's consideration of JGN's proposal
		Energy Project', and signed a Memorandum of Understanding with Santos to streamline the assessment process for Narrabri five years ago, yet Narrabri remains unapproved. The LNG facility approvals are even less advanced so a two year turnaround seems unlikely.
4: Appoint a Coordinator to lead work on critical gas projects by 2020	The NSW government should appoint a Coordinator to progress critical gas projects through the approval processes and ensure that government resources and priorities are properly applied. It should make certain that the Coordinator has access to people experienced in natural gas developments, to ensure that the specific technical issues raised in natural gas projects can be given appropriate scrutiny.	If this vital coordinator role is not appointed at the time of making its decision, the AER cannot presume that NSW won't face gas shortfalls that will affect JGN's market demand and asset lives after 2025.

4.5 Investment incentives

The AER draft decision states:[93]

> *We do not consider that depreciation is an appropriate tool to reduce a network service provider's exposure to potential network-wide asset stranding risk. Stakeholders' submissions raised that the potential stranding of gas infrastructure assets is an industry-wide issue, with the ECA advocating for the development of a national strategy for addressing such issue.*

We have proposed this change on a prospective basis. The incentive effects of suggesting network stranding of an ex ante capex allowance are simply perverse. Inherent in the above statement is the message to investors 'you just spend the money now, even though you are concerned about whether the market for your services will exist in 50 to 80 years' time, and we'll decide later if you can recover that investment'.

The AER's analysis of this issue must not conflate the treatment of sunk investments with that of those not yet made. To do so fundamentally ignores the different incentives that attach to each of these.

The AER draft decision also states about investment incentives:

> *Our specific concerns are:*[94]
>
> *(a) Whether the capex is warranted – If utilisation of the network is expected to fall significantly, it would be questionable whether the capex should be approved in the first place. Rather than accelerating depreciation on new assets, providing service providers with incentives/funding to extend the lives of existing assets, instead of building new assets, may be preferable. Other alternatives, such as requiring greater upfront connection costs for augmentation, could also be a better solution for specific areas of concern rather than a change to a depreciation approach that affects all new assets and customers in the same way.*
>
> *(b) Accelerated depreciation can encourage early asset replacement – If the asset is largely depreciated before its useful life ends, the service provider may be encouraged to replace the asset sooner than necessary. The lower returns in later years (given the asset value has been quickly depreciated away) may provide incentives for early asset replacement to maintain prices at higher levels. More generally, it is questionable whether a service provider would be willing to continue to*

93 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 47

94 Ibid, page 46

operate an asset for many years on which it is getting very little return, having recovered most of its money in the early years of the asset's life.

The capex is warranted

The capex we have proposed for the next AA period is conforming capex in that period. We must provide the service performance that our current customers expect and are willing to pay for. Where we can do this through measures to extend the life of existing assets that we would otherwise replace, we will always do so because:

- We now face balanced incentives for capex and opex efficiencies through operation of incentives schemes on each expenditure type in the 2020-25 AA period.
- Even at the proposed shortened standard asset lives for this sub-set of our asset classes, JGN will still face a risk of these assets having even shorter economic lives in the future, a risk that would bias our decisions to extend asset lives rather than replace assets.
- Our return on capital does not compensate us for bearing the risk of asset stranding, a decision the AER made when it aligned our WACC with electricity networks even through there are no asset redundancy provisions in the National Electricity Rules of the form found in Division 4 of the NGR.

High customer connection contributions are not a preferable alternative

Our growth capex proposed for the next AA period satisfies rule 79(2)(b) based on our proposed tariffs.

As we explained in our initial proposal at Table 2-1, we tested this option with our customers in our engagement. While it was supported in principle, this was on the assumption that it lowered prices. However, when we undertook further research, it indicated that introducing a charge for standard connections would influence some potential customers not to connect to gas (a $300 charge would result in around 23% of potential customers choosing not to connect). This would actually increase bills for all customers over the long term.

To suggest that accelerated depreciation will encourage early asset replacement in JGN's context is simply wrong

Faced with asset stranding risk of the kind JGN faces, together with no economic compensation for this risk in our WACC, it is at best academic and at worst unsophisticated for the AER to suggest that we would recklessly replace our assets earlier than we need to and avoid regulatory tests of prudency and efficiency.

As a provider of fuel of choice, and as network business that authentically engages with its customer to deliver services in a way to address affordability concerns, the crude rationale in the draft decision breaks down relatively quickly. Having assets that are technically working even after they have been repaid enables us to provide cheaper more competitive services to our customers and we will operate them in this manner rather than replace them. This is supported by:

- The genuine competitive constraint we face from the cross-price elasticity of delivered electricity to gas prices
- The fact that our operating costs are funded even if the asset is fully depreciated
- The fact that this scenario is directly analogous to us operating gifted assets (e.g. from developers) or assets that have been subject to a 100% capital contribution, a situation in which we would never then replace those assets ahead of the end of their serviceable life
- The fact that we would still need to get the AER to approve this replacement capex both ex ante or in the RAB roll forward, and if the above incentive were real our risk in doing so would be high thereby further removing any such incentive, and
- The fact that for this incentive to work, the AER's allowed WACC would have to be higher than our actual risk adjusted financial costs.

Incenta reached a similar conclusion on this AER draft decision matter: [95]

> *The AER's concerns about inefficient future use and investment assume a situation whereby the Regulatory Asset Base (RAB) becomes fully (or largely) depreciated in the future, even though the assets remain in service. We observe that this outcome is very unlikely to occur because:*
>
> - *the gas Rules encourages asset lives to be reviewed on an ongoing basis, and so if it became clear that gas assets would remain in service, the lives could be adjusted and depreciation dialled back (indeed, a hold could be placed on depreciation), and*
> - *if a conversion to hydrogen takes place, substantial capital expenditure will be required, and so a material overall RAB would remain.*
>
> *Moreover, even if the assets were to become fully (or largely) depreciated, then:*
>
> - *Inefficient over-use is unlikely – as the efficient price signal is one that reflects forward-looking costs only, which are typically near-zero for a distribution network until capacity constraints are reached,[96] and*
> - *Inefficient over-investment is unlikely – as there are financial incentives to discourage this (noting that JGN is subject to a capital expenditure sharing scheme), together with the opportunity for ex ante and ex post regulatory action.*

4.6 Benchmarking of standard asset lives

The AER draft decision states:[97]

> *… we do not consider the proposed shorter standard asset lives for the 'Trunks', 'HP mains', 'MP mains' and 'MP services' asset classes are consistent with those asset lives applied by other gas distributors for similar asset classes.*

Our proposal to shorten the standard asset lives of these asset classes is driven by a change in their likely economic lives relative to our current remaining asset lives which we understand were based on their technical design lives.

While it may be reasonable to expect technical asset lives to benchmark closely across gas distribution networks, it is not reasonable to expect their economic lives to do so. This is because the markets in which Australia's full regulation distribution pipelines operate are very different.

JGN is seeking the AER to consider the prospective external environment and the reality of significant step changes in environmental policies, financials subsidies, and evolving technologies that have an impact on the future of gas distribution networks. Benchmarking and precedent decisions cited by the AER, are retrospective in nature and therefore would naturally be a self-fulfilling path to a no-change approach. The regulatory framework and rules are sufficiently flexible to ensure that the changing future trends and outlook for the sector is better reflected in prospective decision on economic asset lives.

Even if benchmarking is appropriate, AER has not reflected any business and operating circumstances in its decision making. JGN is the northernmost full regulation gas distribution network in Australia. Our gas market characteristics are very different to southern networks because so much of their loads are for heating. We would expect the pressures affecting the economic life of our service to arise sooner in NSW than in southern markets.

95 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, pages 4 and 5.

96 Capacity constraints in the gas assets that can be used for hydrogen are unlikely (i.e., likely to be only the non-steel assets) as these are typically built with substantial redundant capacity, and because a loss of customers would be expected on conversion to hydrogen.

97 AER, Attachment 4: *Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 25

The greater market threat posed by substitution to electricity in warmer climates must be recognised in how they are regulated. The threats to the markets of gas distributors in Queensland have already been recognised in the National Competition Council determining to apply light regulation to the two distributors that were formerly subject to full regulation there: APA's All Gas network and AGIG's (formerly Envestra) Queensland Gas Distribution Network. For example, the Queensland Gas Distribution Network's application for light regulation stated: [98]

> *Envestra is not in a position to exercise market power in regards to the services provided on the Queensland gas distribution network (QGDN). This reflects that natural gas is a fuel of choice, there are readily available substitutes for natural gas that can be accessed at a low cost and natural gas has no clear competitive advantage over electricity or liquefied petroleum gas (LPG) in the Queensland energy market.*
>
> *This lack of market power is evidenced by the very low penetration rate and customer usage of natural gas in Queensland.*

While we remain subject to full regulation, it would be an improper application of the depreciation criteria to assume that the economic lives of our assets will mirror those of our southern peers. For example, in 2017-18 JGN has average consumption of 19.1GJ per connection which is approximately two thirds of the national average of 31.3GJ/connection and less than 40% of Victorian gas distributors who averaged 50.7GJ/connection that year.

4.7 Efficient growth in the market for reference services

Flat cost recovery out to 2105 will no longer support efficient growth

The AER draft decision states:

> *In general, we consider that consistency in the standard asset life for each asset class across access arrangement periods will allow reference tariffs to vary over time in a manner which would promote efficient growth in the market for reference services.*[99]

We cannot see an evidentiary basis for this claim nor how it can be an accurate application of the depreciation criteria to assert this.

It is undeniable that the growth in the NSW market for gas will be a function of the price of delivered gas to consumers. Those consumers are currently faced with forecast increases in they cost of using gas associated with:

- Increases in the price of wholesale natural gas.
- Gas needing to be transported further across Australia than in the past.
- Gas potentially blended with materially higher priced hydrogen than current natural gas price, which will be compounded by:
  - the greater required volumes of hydrogen due to its relative lesser heating properties
  - higher unaccounted for gas (**UAG**) due to the smaller and odourless hydrogen molecules escaping the network more
  - significant costs of network investment to facilitate hydrogen transportation and metering, and
  - customer appliance switching and appliance retuning costs.

98 Envestra, *Application for Light Regulation of Envestra's Queensland Gas Distribution Network*, 15 August 2014, page 1.

99 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 12.

In this clear and present context, asserting that retaining current flat levels of network cost recovery based on 'generally accepted' legacy technical lives out to 2105 is the '*manner which would promote efficient growth in the market for reference services*' is incredible.

Incenta's conclusions directly refute the AER's logic here

Section 3.4 of Incenta's report (Attachment 8.3) assesses our proposal's ability to support efficient growth in the use of gas. The report's conclusions do not support the above draft decision view and favour our proposal: [100]

> *To date it has been assumed that (i) targeting prices that remain approximately constant in real terms over time would be expected to provide for the most efficient spreading of residual costs over time, and (ii) straight line depreciation over the technical lives of the assets will achieve this in approximate terms. However, the current dynamics in the gas markets provide reason to question both of these assumptions.*
>
> *First, the projected decline in the rate of consumption per customer means that the continued use of straight-line depreciation may not deliver a constant price in real terms so that an efficient spreading of residual cost would imply more accelerated depreciation. Moreover, the projected increasing competitiveness of electricity as a substitute for gas would suggests that a price path that declines in real terms – and so reacts to the increasing price sensitivity of gas consumption over time – would be efficient.[101] This increasing demand sensitivity would suggest that allocative efficiency would be advanced by increasing the portion of residual costs that are recovered earlier (i.e., targeting a trajectory of prices that is declining over time).*
>
> *Secondly, in conjunction with the above point, even if it is assumed that a conversion to hydrogen occurs, then substantial costs will be incurred at the time to convert the pipeline network to one that is suitable for hydrogen. Moreover, the process of conversion to hydrogen would be likely to see a reduction in the number of customers served given that it may not be economic to reticulate hydrogen to all areas currently served by natural gas, and because there is the prospect that, as customers will be required to install new appliances if reticulated hydrogen eventuates, at least some will decide to convert to electrical appliances instead.*
>
> *Thirdly, the discussion above focusses only on the transportation component of the natural gas supply, whereas the efficiency of use of the gas pipeline will depend on the combination of movements of all components of the delivered gas price. To this end, the discussion in Chapter 2 noted that:*
>
> - *the price of natural gas is projected to continue to increase materially over time, and*
> - *if reticulated hydrogen does become efficient, the cost of the commodity component is projected to be materially higher than the cost of natural gas.*
>
> *These projected movements in the price of the gas commodity provide further reason to advance the recovery of capital for the gas pipeline network, that is, to provide a greater capacity for customers to be able to absorb these future cost increases.*
>
> *Thus, our view is that it is plausible that the current gas dynamics would provide a reason to accelerate depreciation even if the stranding risks were not considered material.*
>
> *Lastly, in relation to intergenerational fairness, whilst we note that this is not an economic concept and further that this is a multifaceted concept, there are aspects of JGN's proposal to advance depreciation that we would expect to advance intergenerational equity, in particular:*

---

100 Incenta Economic Consulting, *Using asset lives to manage stranded asset risks*, December 2019, pages 23 and 24.

101 That is, if the price sensitivity of gas consumption is expected to increase over time then the loss in allocative efficiency (i.e., demand that is dissuaded even though the marginal benefit of consumption exceeds the marginal cost) from a 1% increase in price today would be lower than the allocative loss from the NPV-neutral price increase at a future time, in which case advancing depreciation would raise allocative efficiency.

- *the proposition that a greater contribution to the network should be secured during times when the use of the assets is at their greatest, and*
- *that it is valid to use the pattern of recovery of network costs to ameliorate the potential for price increases to future generations arising from an increase in the cost of the gas commodity, and especially to smooth the transition to hydrogen given that the need to make such a transition is to remedy environmental issues that are the result of current and past generations.*

Short-term pricing impacts will not worsen the future situation as much as waiting will

The AER draft decision also states:[102]

> *Higher depreciation and prices in the short term may accelerate any decline in utilisation. That is, higher prices (caused by accelerated depreciation) may discourage customers to connect to the gas network.*

This statement is flawed in that:

1. The price impact of this change will be imperceptible from a behavioural response perspective in the 2020-25 AA period, and
2. It is only a relevant consideration if any response in 2020-25 is higher than the equivalent response will be in future.

The customer impact on this change based on our revised proposal is $2.10 per year. That is, compared to a price reduction of 21.84% we are now proposing a reduction of 21.25%.[103] Such a price impact is likely to be imperceptible in retail bills and not drive any significant behavioural change during the period.

If you assume that it does have a behavioural response in the next period, it is only a relevant consideration if the customer elasticity response now is higher than it would be in future. The changes in the price of renewable electricity (lower) and green hydrogen (higher), mean the delivered gas price competitiveness with electricity will fall in future relative to now.

Depreciation criterion *(a)* requires that the depreciation schedule should be designed '*so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services'*. And the NGO requires that AER decisions support efficient use in our customers' long-term interests. We are trying to support lower longer-term gas price to support efficient longer-term use.

The above AER statement is only a valid consideration if it considers that the relative impact in the next five years will be higher than over the remainder of the economic life of the assets after 2025. The simple fact that existing household appliances have an average life of seven years paired with the trajectory of the Core Energy forecasts from 2030 onwards show that this is simply not a credible scenario.

4.8 Addressing the AER's comments on long-term bill impacts

The AER states that it has *'some issues with the underlying assumptions and presentation of the analysis'* that we provided on long-term bill impacts.[104]

Specifically, the AER raises concerns with

- Our presentation of information in nominal dollar terms.

---

102 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 46.

103 These are the respective year 1 P0s, assuming the same x factors in years 2 to 5 as in our proposed price path, as set out in section 12.2 of our Revised 2020 Plan.

104 *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 30 and Appendix C.

- The declining volume trend assumption that our long-term bill analysis was based on (presented in Appendices A and B of Attachment 7.10 of our 2020-25 AA Proposal).
- Bill impacts under flat or increasing volume scenarios.

We do not agree with the AER's criticisms of our approach to presenting long-terms bill impacts to our customers on this topic. We discuss each of these in turn in the following sections.

4.8.1 Dollar basis for presenting long-term bill impacts

We presented long term bill impacts to our customers on a nominal dollar basis. In its draft decision, the AER has criticised this approach. It states:

> *In our view, presenting the price impact figures in real dollar terms is a better approach when comparing the difference in the bill amount across periods and over a long period of time.*[105]

We do not agree with the AER's view and we note that it is in direct contrast to the AER's CCP advice when it undertook its review of JGN's 2015-20 AA Proposal, when it criticised JGN for presenting bill impacts in *real dollar terms.* In stated:[106]

> *We also question whether customers understand the significance of figures that are presented without the effects of inflation. We suggest that customers are not used to seeing figures presented in that way, and do not fully allow for inflation in their minds when they do see such figures.*
>
> ***…. We believe customers would better understand price changes after forecast inflation, and would be more protected from over-estimating the benefits to customers of the JGN proposal through lack of consideration of the effects of inflation.*** [Emphasis added].

Consistent with the CCP's observations, we note that the concepts of 'real' and 'nominal' are not easily understood by the broad range of customers we engaged throughout our engagement program—the vast majority of customers that we engaged with had no financial qualifications.

The AER's criticism of our customer engagement appears to be inconsistent with its own standard approach for regulatory decisions—the AER itself presents its bill impacts in nominal dollars, for example:

- In its draft decision for JGN's 2020-25 AA[107]
- In the draft decision for SAPN[108]
- In its draft decision for Ergon Energy[109]
- In its draft decision for Energex[110]
- In its final decision for Ausgrid.[111]

It is important to point out that our engagement program was delivered in conjunction with our engagement partners Straight Talk/RPS, customer engagement professionals that helped us deliver our engagement program in accordance with International Association of Public Participation (**IAP2**) principles. This included input and

105 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 52

106 CCP, *Advice to AER from Consumer Challenge Panel sub-panel 7 regarding Jemena Gas Networks (NSW) Access Arrangement 2015-20 Proposal*, 3 September 2014, page 15

107 AER, *Draft Decision Jemena Gas Networks (NSW) Ltd, Access Arrangement 2020 to 2025, Overview*, November 2019, page 12

108 AER, *Draft Decision SA Power Networks Distribution Determination 2020 to 2025, Overview*, October 2019, page 18

109 AER, *Draft Decision Ergon Energy Distribution Determination 2020 to 2025, Overview*, October 2019, page 19

110 AER, *Draft Decision Energex Distribution Determination 2020 to 2025, Overview*, October 2019, page 19

111 AER, *Final Decision Ausgrid Distribution Determination 2019 to 2024, Overview*, April 2019, page 19.

advice from Straight Talk/RPS to ensure that the information presented during our engagement program was clear and fit for purpose.

Further, representatives from either ECA, PIAC, ECC and CCP attended all of our customer forums in at least one location. At no time did they raise any concerns with how we had presented bill impacts. Similarly, we shared our engagement materials with the ECA, PIAC, ECC and CCP ahead of the engagement session that they attended, and at no time did they raise any concerns with how we intended to present bill impacts.

Moreover, our customers told us that they wanted to know what they would actually be paying for their gas use. When presenting information to them we did show the impacts of inflation without getting into a complicated discussion about the meaning of 'real' versus 'nominal'. We did this by showing the minimum wage in nominal dollars after tax both today and in 2060. This provided our customers with additional context about the impacts of the change in asset lives relative to the average minimum wage.

As we presented bill impacts under two scenarios, any impacts of using a nominal instead of a real price base impacted both scenarios equally. At no stage did any of our customers attending the forums tell us that they were confused with our bill analysis.

4.8.2 Declining volume trend scenario

The AER notes that the declining volume assumptions that we relied on when presenting long term bill impacts to customers is not consistent with AEMO's forecast of annual gas consumption in NSW.

In Table 4.5 of Appendix C of its draft decision, the AER compares the volume assumptions that we used in our declining network scenario against AEMOs forecasts from its 2019 GSOO. Importantly, the AER has only included one of the two scenarios that we presented to customers, and in doing so, has misrepresented how we tested this issue with our customers.

We presented two scenarios to our customers:

- Network Declines: a declining volume scenario, which represented what might happen should hydrogen not be proven to be technically and/or economically viable for use in distribution pipelines
- Network Thrives: an increasing volume scenario, which represented what might happen should hydrogen be proven to be technically and/or economically viable for use in distribution pipelines.

The volume scenarios that we tested with our customers and those in AEMOs 2019 GSOO are show in Table 4–2.

Table 4–2: Volume assumptions for customer engagement on asset lives and AEMO's 2019 GSOO scenarios

Scenario	RY26 to RY30	RY31 to RY35	RY36 to RY40	RY41 to RY45	RY46 to RY60
Network declines	1.00%	-1.35%	-2.7%	-5.4%	-10.8%
AEMO - Fast scenario	0.70%	0.68%	0.60%	N/A	N/A
AEMO – Neutral scenario	0.45%	0.43%	0.36%	N/A	N/A
AEMO – Slow scenario	0.34%	0.25%	0.13%	N/A	N/A
Network thrives	1.00%	1.00%	1.00%	1.00%	1.00%

For each volume scenario, we showed our customers the impacts of changing versus retaining the current asset lives for new investments. So while we did not rely on AEMO's forecasts for the period to 2038, the volume assumptions that we used effectively book end the AEMO forecasts.

When engaging with our customers, we were also very clear about the uncertainty surrounding the future of gas. For example, in Forum 2, we showed videos which highlighted different views about what the future may hold, including the future of gas. We did this to ensure that customers heard different views across the industry, rather than just Jemena's views. It was only after providing this context that we tested asset lives with our customers. By presenting the two book end scenarios, and by being very clear that we do not know what the future holds, our customers understood that the outcomes arising from either changing or maintaining the current asset lives would vary depending on the outcome for gas.

As we discuss in section 4.4, it is important to recognise that the AEMO forecast is just one of many, and that it represents a forecast at a point in time, and does not appear to explicitly model the effect of significant, increasing, and evolving electrification incentives, or any other step changes in the gas demand, such as the effect on consumer behaviour of accelerating NSW net-zero carbon targets. We also show in Figure 4.1 the significant variability in AEMO's forecasts year on year.

Given the above, we do not believe that relying on the 2019 GSOO forecast in our analysis would have changed the outcomes from our engagement with our customers.

4.8.3 Bill impacts under flat or increasing volume scenarios

In its draft decision, the AER states:[112]

..We are not aware of any reasons why asset lives would still need to be reduced under flat or increasing demand trends. We consider that this additional analysis could help better inform customers on the cost impact of JGN's proposed asset lives reduction under scenarios where demand increases or stays flat over time.

It appears from these comments that the AER has misunderstood the information we presented to our customers during our customer forums.

We agree that the showing the impact of shortening asset lives under a scenario where demand increases over time was important to present to help inform our customers in their decision making. It is for this reason that we presented the 'Network Thrives' scenario to our customers (with demand increasing by 1.0% per annum out to 2060).

In making the above comments, the AER cites the analysis that we presented in Attachment B1 of Attachment 7.10 of our 2020-25 AA Proposal. We developed this analysis after our engagement with our customers had concluded, following a submission by the ECA on our Draft 2020 Plan which asked whether the change should be deferred until to the 2025-30 period. The purpose of Attachment B1 was to specifically respond to the ECA's comments, which was to show the bill impacts of deferring the decision.

For the purposes of the analysis in Attachment B1, we assumed that the demand for gas consumption will decline over the time horizon due to decarbonisation initiatives and substitution by electrical products. We also considered an alternative scenario where we compared the options (i.e. acting now or deferring the decision for 5 or 10 years) against a flat volume forecasts, that is, the volumes remain at current levels in all future years. We considered this to be a relevant counterfactual should hydrogen tests be successful and JGN able to maintain the current volumes over the longer term.

On this basis, we do not believe that the AER's criticisms are founded.

4.9 AER inconsistencies

The AER's reasoning for its draft decision on the speculative capital investment fund directly contradicts its reasoning for our standard asset life proposal.

112 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 54

When considering our standard asset lives proposal, the AER states:

> *While there is still much uncertainty about the viability of hydrogen gas at this stage, we consider the introduction of hydrogen gas could have a substantial positive impact on the future of gas distribution networks.* [113]

In contrast, when making its draft decision to exclude the Western Sydney Green Gas Trial from the speculative capital expenditure account, the AER concluded that '*the integration of hydrogen as a fuel requires rule and law changes*' and the AER's reading of the NGL definition of natural gas is that it precludes hydrogen.[114] So on the one hand the AER considers hydrogen as a credible means to secure the longevity of the network, whereas on the other hand, the AER considers that there is too much uncertainty regarding hydrogen and its consistency with the regulatory framework to support the creation of a speculative account.

And further, and arguably more glaring inconsistency in the AER's reasoning to reject our asset lives proposal can be found in its capex draft decision. In that decision it states:

> *For each growth driven augmentation project, JGN has selected to justify its capex expenditure by carrying out analysis to demonstrate that the revenue generated as a result of the expenditure exceeds the present value of the capex. JGN has also carried out the analysis based on an investment horizon to 2050, and an investment horizon to 2070 where no further costs and benefits are taken into account post that time.*
>
> *In line with our previous decisions, we do not consider costs and benefits for these types of investments beyond 30 years given uncertainties beyond that point. As such, we do not accept JGN's incremental revenue analysis for an investment horizon to 2070.*[115]

The AER's standard asset lives decision is underpinned by the principle that JGN should be willing to rely on the assumption that current demand, and therefore, revenue levels will persist and therefore enable recovery of our 2020-25 capex investments out to 2105. However, to the contrary, the AER in its capex draft decision explicitly states that there are uncertain costs and benefits after 30 years that preclude their consideration of longer-term investment decisions.

113 AER, *Attachment 4: Regulatory depreciation | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 23.

114 AER, *Attachment 5: Capital expenditure | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, November 2019, page 5-71.

115 Ibid, pages 5-54 to 5-55.