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Dear Andy

Resetting DPPs for gas pipeline businesses from 1 October 2022: Process and issues paper

First Gas Limited (Firstgas) welcomes the opportunity to submit on the Commerce Commission's (the Commission) consultation paper "*Resetting default price-quality paths for gas pipeline businesses from 1 October 2022: Process and Issues paper*". We are making this submission on behalf of our gas transmission business (GTB) and our gas distribution business (GDB).

Summary of key points

The Commission has prepared a well-considered process and issues paper that captures the significant changes facing the gas sector and the range of issues to be considered when resetting the Default Price-Quality Path (DPP) from 1 October 2022 (DPP3). We acknowledge that the Commission has tried to find pragmatic solutions that recognise the uncertainty facing the gas sector and the time and resources available to resolve issues through the DPP3 reset.

We believe that capital recovery is the single most important issue for the DPP3 reset. This is because the significant changes that the Commission describes in the paper will have an impact on investment incentives within the coming regulatory period. It is critical that the Commission adjusts asset recovery parameters now to:

- Provide suppliers with confidence that further investments to maintain network safety and reliability and prepare for the option of renewable gases make financial sense and
- To reassure gas users that future price rises will be moderated to the extent possible within the regulatory framework.

Together with Vector and Powerco, we have commissioned three expert reports[1] that investigate the capital recovery risks facing gas pipeline businesses (GPBs) in New Zealand and evaluate possible solutions. These reports highlight the scale of the issues we face. Even without any further investment, GPBs will have unrecovered Regulated Asset Bases (RABs) of more than $600 million in 2050 under current regulatory settings. The recent advice of the Climate Change Commission (CCC) forecasts total natural gas demand of 25 PJ per year in 2050. In combination, those facts lead to a ratio of fixed capital to demand that is more than quadruple the ratio today.

[1] The expert reports from Frontier Economics, Houston Kemp, Oxera are attached to a cover letter from the Gas Infrastructure Future Working Group (GIFWG), which we have provided along with our individual company submissions.

The expert reports identify a range of regulatory tools that can help to address this challenge and describe how regulators in Europe have made changes to the regulatory framework to help address the same risks facing European gas pipelines. The two measures that we believe the Commission should closely consider for DPP3 are to remove RAB indexation and to provide accelerated depreciation. Individually, and in combination, these measures would materially reduce exposure to unrecovered investment, mitigate consumers' exposure to future price escalation, and provide confidence to continue to invest.

We acknowledge that prioritising capital recovery means that there may be less time available to analyse other issues usually considered at a DPP reset (such as expenditure forecasts and quality standards), and that other desirable changes to the Input Methodologies (IMs) may not be possible. For the reasons set out in this submission, we believe that this is an appropriate trade-off to make, and we are willing to work with the Commission to inform pragmatic decisions for this price-quality reset.

We recommend that the Commission decides on the broad approach that it will take for the DPP3 reset by the end of October 2021. Confirmation of this decision will enable stakeholders to focus their efforts on the issues that will be addressed in the reset and any refinements needed to the processes used to determine allowable revenues. We recommend that the Commission holds a workshop on capital recovery options early in the DPP3 reset process (ideally in October 2021) to explore this issue and possible solutions with stakeholders. If these steps are taken, then we believe it is possible for the Commission to consult on draft IMs amendments before Christmas 2021 and still meet its February 2022 timeframe for releasing the draft DPP3 rest decision.

1. Introduction

The Commission has prepared a well-considered process and issues paper that captures the uncertainty facing the gas sector and the range of issues that should be considered for the upcoming DPP reset. The paper also reflects the range of points raised by stakeholders on the Commission's open letter, primarily that there is a large degree of policy uncertainty and that the current regulatory settings are no longer suitable in this changing context.

To help inform decisions on the DPP3 reset, we have applied an evaluation framework using the three outcomes presented in our submission on the Commission's open letter:[1]

1) Reducing the risk of future price escalation and economic asset stranding
2) Continuing to provide sufficient incentives to invest to maintain reliable gas infrastructure
3) Preserving the option of using gas infrastructure for zero carbon gases in the future.

We have also assessed the approaches and issues for the DPP3 reset against the practical issues associated with implementation (time / resources / complexity / compliance costs). Our evaluation of the options for the DPP3 reset is provided in **Attachment 1**. The options have been grouped into four broad themes: capital recovery mechanisms, DPP reset mechanics, mechanisms for allocating within period demand risk and other possible changes.

This evaluation applies the approaches used for the 2017 DPP reset for GPBs as a benchmark. We recognise that many of the approaches discussed in the Commission's paper are not mutually exclusive. The creates an opportunity for the Commission to bundle some set of approaches together to determine the most effective approach for the DPP3 reset.

In evaluating reset options, we have recognised the interplay with the upcoming IMs review that must be completed by December 2023. We acknowledge the need for the IMs to promote certainty and that at a DPP reset the Commission is unlikely to make changes to fundamental IMs (such as the cost of capital) unless there is a compelling case to do so.

The remainder of this submission discusses the key points that fall out of our evaluation of DPP reset issues and options:

- Section 2 discusses the **importance of capital recovery for this DPP reset**, looking at the nature of the problem, how GPBs are currently addressing the risk of asset stranding, and what regulatory changes we believe should be considered for DPP3
- Section 3 describes why GPBs should **preserve the option of repurposing gas infrastructure**, summarising the work Firstgas is carrying out on biogas and hydrogen, and why we largely agree with the Commission's analysis on the treatment of renewable gas investments under the regulatory framework
- Section 4 deals with **mechanisms to allocate within-period demand risk** and explains why within-period demand risk is a more material issue for gas transmission than distribution
- Section 5 addresses the **mechanics of the DPP reset** including consideration of rolling-over prices versus a building blocks approach, the benefits of a four-year regulatory period, the approach to expenditure forecasts and quality standards
- Section 6 concludes with our recommendations for the **DPP process from here**, explaining why we believe that it is important for the Commission to make early decisions on DPP3 focus areas and reset mechanics, and to workshop the issue of IMs amendments to address capital recovery issues.

Together with Vector and Powerco, Firstgas commissioned the following expert reports to help us better understand the merits of selected approaches for the DPP reset and to provide an update on regulatory practice in Europe, where similar economic asset stranding risks are actively being managed.

- **Frontier Economics** provided advice on RAB indexation and whether there is an economic case for the Commission to adopt a nominal returns framework when regulating gas distribution and transmission networks in New Zealand
- **Houston Kemp** addressed the consequences of an anticipated decline in the use of natural gas in New Zealand for the economic regulation of the gas pipeline businesses by the Commission, including the case for providing accelerated depreciation
- **Oxera** reviewed the regulatory tools that European regulators have used to manage asset stranding risk facing gas networks and to align with the delivery of net-zero targets.

We also draw on the Findings Report from the Gas Infrastructure Future Working Group (GIFWG), which was presented to the Minister of Energy and Resources on 13 August 2021 and will be published in coming weeks. The Findings Report helps to establish a common set of facts and issues, laying a foundation for developing policy and regulation on the future of gas infrastructure.

These expert reports are attached to a cover letter from the GIFWG, which we have provided alongside our individual company submissions. We reference these reports where relevant in this submission.

2. Importance of capital recovery for this DPP reset

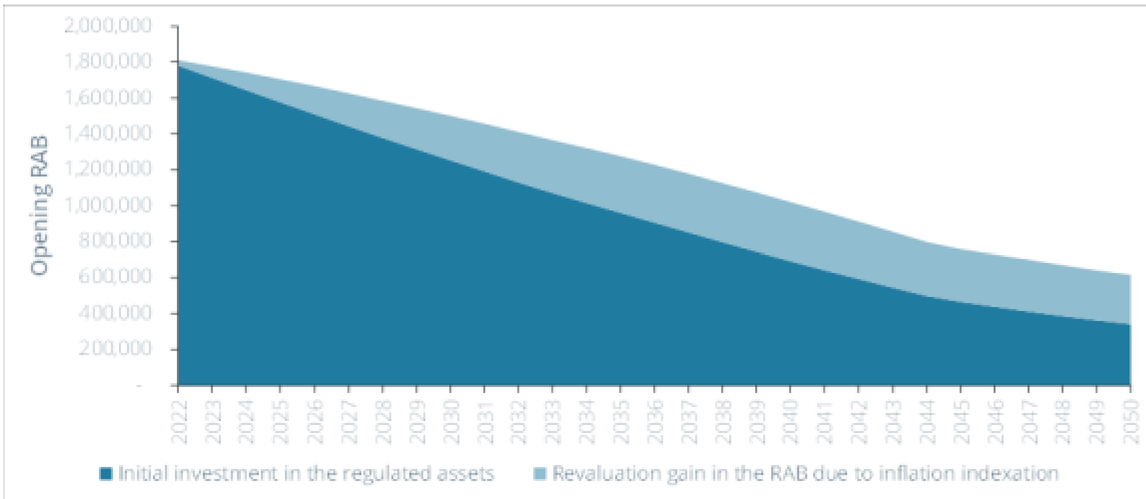
Firstgas believes that capital recovery is the single most important issue for the DPP3 reset. We outline the nature of the problem that GPBs are facing in the sections below, and how we are addressing the risk of asset stranding. We also canvas what regulatory changes the Commission should consider to address this issue.

Nature of the problem

We agree with the Commission's analysis that the gas industry has seen significant change since the last IMs review in 2016, particularly with the adoption of a legislated net-zero carbon emissions target and the resulting policy direction proposed by the Climate Change Commission (CCC). These measures have created uncertainty about whether investors in gas infrastructure will earn a risk adjusted return on their capital and whether the Commission's principle of financial capital maintenance (FCM) can be maintained.

While 2050 is nearly 30 years away, this is a highly truncated timeframe for gas infrastructure investors to recover their capital. A significant proportion of gas pipeline assets have assumed lives under current regulatory rules that extent well beyond 2050. Analysis from Frontier Economics[2] shows that even without further investment, the existing regulatory settings would leave more than $600 million of unrecovered capital in gas pipeline infrastructure. Additional investment will be required to maintain reliable and safe gas infrastructure for those customers who continue to rely on natural gas over coming years, which makes the scale of the issue even greater. This underscores the need for the regulatory parameters to shift to provide capital providers with confidence to continue to invest.

Figure 1: Roll forward of total GPB RABs assuming no additional Capex beyond 2021[3]



From the consumer perspective, the issue of capital recovery becomes more pressing over time as falling demand leads to future price increases. The Houston Kemp report[4] demonstrates how significant this risk is at present, with average pipeline tariffs of around $2/GJ today growing sharply if the CCC's demand projections are borne out. Forecast price escalation is particularly steep from 2040, with average tariffs increasing from $4/GJ to $14/GJ. We consider it unlikely that remaining gas

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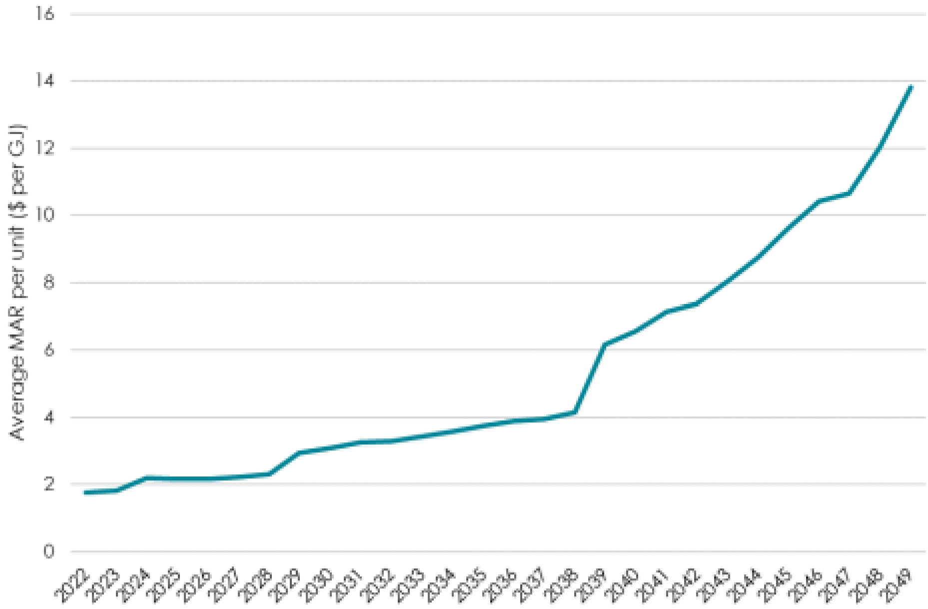
[2] Section 3.2, *The case for a nominal returns framework for regulated gas networks in New Zealand*, Frontier Economics Pty Limited, 27 August 2021.

[3] Figure 3, *The case for a nominal returns framework for regulated gas networks in New Zealand* , Frontier Economics Pty Limited, 27 August 2021.

[4] Section 2.2.1, *Consequences of declining gas pi peline utilisation*, Houston Kemp, 30 August 2021.

users will be willing to pay these prices for pipeline services, highlighting the link between future price escalation and economic asset stranding risk.

Figure 2: Gas industry MAR per unit of projected gas demand, 2022-2049[5]



How are GPBs addressing the risk of economic stranding?

The Commission has asked GPBs to explain how they are addressing the risk of economic network stranding themselves with the tools available.[6]

The first measure that Firstgas has undertaken for our gas transmission and distribution businesses is to review and adjust our approach to growth expenditure (as disclosed in our 2021 Asset Management Plan Updates).[7] Since our business was formed in 2016, Firstgas has focused on encouraging strong growth across our networks. This approach was developed to meet the ongoing and increasing demand for new connections and provided long-term benefits to consumers, as network costs could be spread over a larger consumer base. The recent changes we have observed in policy direction have altered the balance of risk and reward these for investments, and it is therefore appropriate to now reflect this in the level of capital contributions we now seek from customers.

While we have not yet finalised and announced changes to our capital contributions policy,[8] we have factored higher contributions into our 2021 AMP Updates forecasts over the next 10 years. We are also aware that Vector has moved to seeking 100% capital contributions for new gas connections.

Higher capital contributions will inevitably lead to lower connections growth and less need for growth capital expenditure (Capex) for our GDB. As a result of expected changes, the forecast growth and consumer connection Capex in our FY2021 AMP Update for gas distribution has reduced significantly from the expenditure forecast for these categories in the FY2020 AMP Update. Where 12 months ago we were expecting growth expenditure to increase from around $12 million per year to $14 million per year over the coming regulatory period, we now expect this expenditure to fall to around $8 million per

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[5] Figure 2.3, *Consequences of declining gas pipeline utilisation* , Houston Kemp, 30 August 2021.

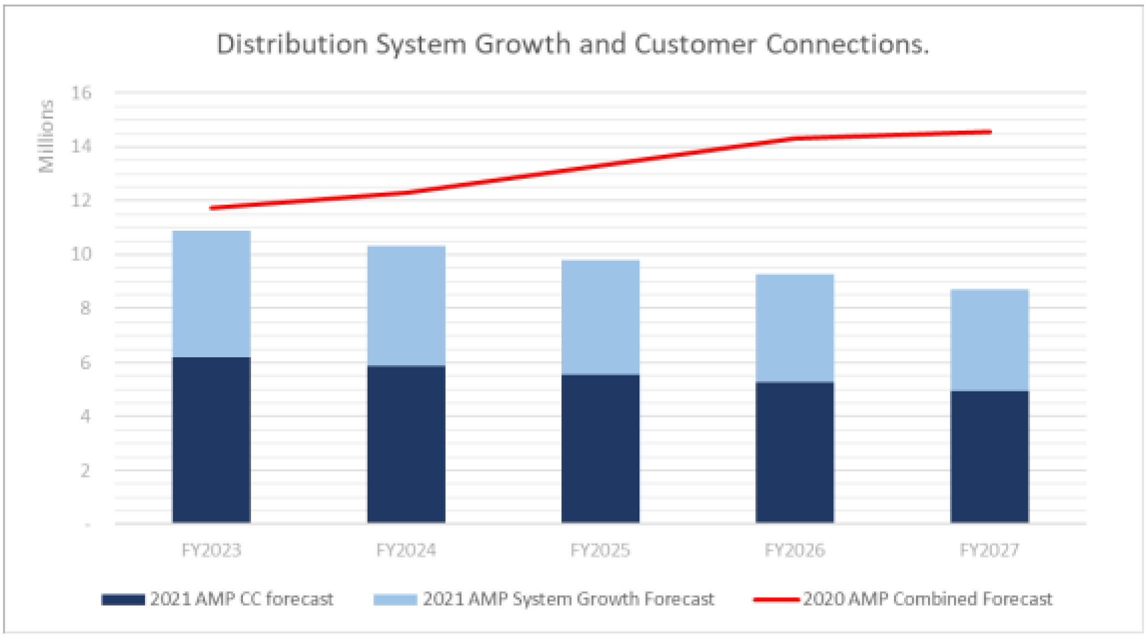
[6] Paragraph D16, *Resetting default price-quality paths for gas pipeline businesses from 1 October 2022: Proces s and Issues paper*, Commerce Commission, 4 August 2021.

[7] Our 2021 AMP Updates for our GTB and GDB will be made publicly available by 30 September 2021, and available here: https://firstgas.co.nz/about-us/regulatory/

[8] We will announce changes to GDB capital contributions policy in coming months.

year (a drop of around 40%). This trend is shown in the bars in Figure 3 below, with the red line showing the trend presented in our previous AMP.

Figure 3: Customer connection and system growth capital expenditure



Other areas of capital investment are also coming under more scrutiny within our business, including the asset replacement and renewals programme for both our GTB and GDB. We have a very low tolerance for asset failure, and the regulatory standards imposed by the Commerce Commission and under *AS2885*[9] require us to anticipate network integrity risks and invest prior to failure. Nevertheless, ongoing uncertainty about capital recovery will drive us to carefully consider how we invest and the planning horizon we use to support required investments.

Another step we are taking to mitigate the risk of asset stranding is to explore alternative uses of our assets – including repurposing our networks for hydrogen and biogas. The implications of these investments are discussed further in Section 3 of this submission.

We have included expenditure in our 2021 AMP Updates to complete the hydrogen network trial described in our report on hydrogen pipeline conversion released in March 2021.[10] We are working with other GDBs on this trial programme, and we note that the Vector gas distribution AMP Update also includes hydrogen trial expenditure. Although these investments are not yet large in terms of overall pipeline capital expenditure, we believe that they are prudent given the risks that we face. We have strong incentives to ensure that our assets provide the maximum value over the long term – and preserving the option of repurposing assets to fit with New Zealand's net zero target provides an important opportunity to realise long-term value.

We have also started to assess possible changes to our pricing methodologies. The Commission's pricing principles state that where prices based on incremental costs would under-recover allowed revenues, then the shortfall should be made up by prices that have regard to consumers' willingness to pay. Our current pricing methodologies incorporate various measures to achieve this outcome, including non-standard agreements that reflect the different alternative energy supplies available to

[9] Australian and New Zealand standard (AS/NZS) 2885 suite of Standards for High Pressure Pipelines.

[10] *Bringing zero carbon gas to Aotearoa: Hydrogen Feasibility Study – Summary Report*, Firstgas Group, March 2021, https://gasischanging.co.nz/assets/uploads/Firstgas-Group_Hydrogen-Feasibility-Study_web_pages_R1204.pdf

gas users. The prospect of future reductions in natural gas use will require us to look at how we earn our regulated revenue from the prices we charge to different customer groups.

What would we do if we were not regulated?

The Commission also asks what we would do to manage asset stranding risks if we were unregulated.[11] The simple answer is that we would not increase the valuation of our existing assets and we would seek to accelerate capital recovery through our pricing decisions.

The value of our assets disclosed in our financial accounts has not increased over the past five years, whereas the value of our transmission and distribution RABs has increased by more than $70 million over that time due to inflation indexation. The Commission has previously noted that not indexing RABs for inflation is more consistent with Generally Accepted Accounting Practices (GAAP)[12] and we believe would also be more consistent with current market conditions.

No business willingly accepts a high risk of having substantial unrecovered fixed capital investment and will rationally seek to bring forward capital recovery. Market prices provide a natural constraint on firms' ability to recover capital in unregulated markets, and customers must be willing to pay higher prices for the services they provide.

We encourage the Commission to explore the growing literature on the effect of climate change policies on asset stranding risk in unregulated markets. We believe that this supports our view that firms expect to recover their investments and that where the useful life of assets is truncated by policy changes then firms will look to bring forward capital recovery.[13]

What regulatory changes do we believe should be considered?

The risks to capital recovery cannot be managed by GPBs alone. Regulatory change is also required. The changes that we believe have the most merit are explained in detail in the expert reports that we have commissioned alongside Vector and Powerco – namely to remove RAB indexation and to accelerate depreciation rates for regulated assets.

Removing RAB indexation reduces risk of economic stranding and improves intergenerational equity

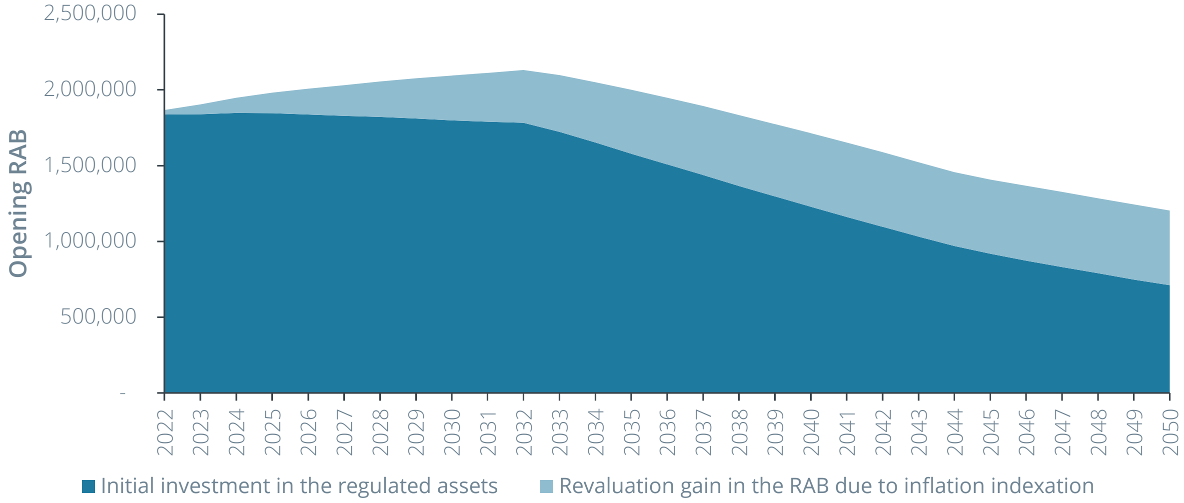
Frontier Economics sets out the case for removing RAB indexation and moving to a nominal returns framework for regulated gas networks in New Zealand. Figure 4 below illustrates how this single change would reduce the risk of economic stranding by close to half – without changing the prices paid by consumers in present value terms.

[11] Paragraph D16, *Resetting default price-quality paths for gas pipeline businesses from 1 October 2022: Process and Issues paper*, Commerce Commission, 4 August 2021.

[12] See page 29 of Transpower-IPP-reset-Issues-paper-7-February-2019.PDF (comcom.govt.nz)

[13] *Climate policy, stranded assets, and investors' expectations*, Journal of Environmental Economics and Management, March 2020, ScienceDirect website, https://www.sciencedirect.com/science/article/pii/S0095069618307083

Figure 4: Asset stranding risk with and without RAB indexation[14]



In addition to resolving the accumulation of RABs, Frontier identifies a range of other reasons why a nominal returns framework may be better suited to GPBs at this time.[15] We agree with the conclusion that a nominal returns framework would likely improve intergenerational equity between gas consumers today and in the future and would provide additional near-term cash flow to preserve the option of repurposing (discussion further below).

Early introduction of accelerated depreciation reduces the prospect of future price instability

Houston Kemp explores the implications of providing accelerated depreciation at the upcoming DPP reset. The key conclusions from this work are that:

- There are clear advantages to taking early action to respond to economic asset stranding risks. Houston Kemp demonstrates that waiting until the next price-quality reset to address the issues identified by the Commission will lead to higher prices in the future.
- Optimal depreciation allowances for GPBs are likely to be around 30% higher than current rates of depreciation in the IMs. This result is achieved by comparing prices that are consistent with a long-term stable trend that recovers capital invested with the prices resulting from different levels of accelerated depreciation. This is shown in the graph below and demonstrates that 15% acceleration is clearly insufficient since the price path remains well below the optimal stable path. In contrast, 50% acceleration would be too rapid since the price path fluctuates above and below the optimal stable path.

Houston Kemp concludes that a reduction in asset lives in the order of 15% to 35% would help to return prices to a level close to a smoothed price path, significantly reducing the prospect of further price instability and unpredictability from 2027.

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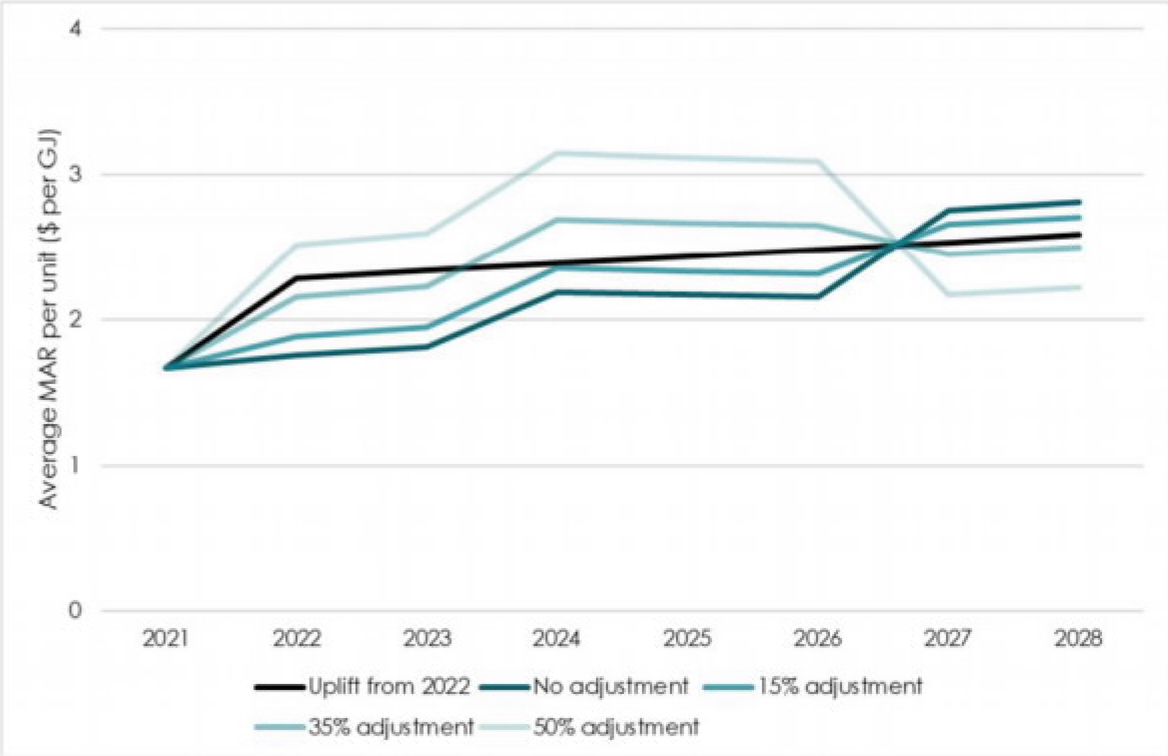
[14] Figure 4 of the Frontier report.

[15] See paragraph 17 of the Frontier report.

Figure 5 Near-term price path trajectories with accelerated rates of depreciation[16]



<u>International regulatory precedents support use of capital recovery mechanisms</u>

Oxera surveys the approaches that regulators in Europe have taken to address the same risk of economic asset stranding identified by the Commission. European approaches are particularly relevant to New Zealand because these countries apply a similar style of economic regulation to gas pipelines and have made strong, often legislative, commitments to net zero emissions.

Figure 4.1 of the Oxera report summarises the approaches adopted – illustrating that each of the five regulators surveyed have adjusted the regulatory framework to address the risks facing gas pipelines, with some regulators using a combination of measures. Our preferred combination of measures (removing RAB indexation and accelerating depreciation) has been adopted in the Netherlands, which we believe provides a useful precedent for the DPP3 reset.

While the Oxera work also canvasses other solutions that regulators have applied to provide greater confidence of capital recovery, we see reasons for focusing on a subset of possible solutions as part of this DPP reset. Given the time available for the DPP3 reset, we are not convinced that a revenue uplift to compensate for stranding risk is the best path forward, since that mechanism would face real estimation error risk and may need to be quite large to address the level of risk involved.

3. Preserving the option of repurposing gas infrastructure

We strongly support the development of a renewable (zero-carbon) gas industry in New Zealand. We believe that it has good prospects, not only to support the country's net zero target, but also to increase energy resilience, enhance reliability, and to help manage risks around energy affordability. The Commission has been briefed on our work programme exploring the potential for green hydrogen

[16] Figure 3.3, Houston Kemp report.

and biogas.[17] Our Hydrogen Feasibility Study shows that we can introduce hydrogen into the Firstgas pipeline network from 2030 and convert to 100% hydrogen by 2050. Our biogas report (jointly sponsored by Fonterra, Beca and EECA) identifies organic waste streams sufficient to produce around 20 PJ of biogas.

If these zero carbon alternatives to natural gas can be deployed at scale, then many of the risks facing our business will be substantially mitigated. This repurposing also has strong customer support, with over 80% of participants at a recent Firstgas webinar supporting our work to date on the use of net zero carbon gasses in our networks.[18]

The key point for the DPP3 reset, which the Commission acknowledges, is that the future demand for renewable gas is uncertain. Critically, the economics of both green hydrogen and biogas are driven by the costs of production and access to key inputs (such as electricity and organic waste feedstocks). As a result, GPBs cannot control the ultimate prospects for renewable gas. However, we can, and should, preserve the option of distributing these fuels using existing pipeline infrastructure, since this will be the most cost-effective channel to market.

We largely agree with the Commission's analysis that investments to facilitate hydrogen and biogas can be considered part of conveying natural gas if they do not require changes to existing infrastructure and appliances.[19] We do however recommend that the Commission treat the conveyance of biogas in the same manner as the conveyance of natural gas. Biogas (when purified to be biomethane) has the same chemical composition as natural gas, which means that no changes are required to existing gas infrastructure or gas appliances when biomethane is injected.

We believe that the zero carbon trials and investigations we are pursuing (along with other GPBs) highlight that the current regulatory settings do facilitate the option of repurpose gas infrastructure at this time. Accordingly, we do not see the need to prioritise an innovation allowance at this DPP reset (as is currently available for Electricity Distribution Businesses, EDBs). This may change as the industry gathers momentum and is therefore a matter that we believe would be better considered as part of the upcoming IMs review.

4. Mechanisms to allocate within period demand risk

In our view, there is no pressing need to review the form of regulatory control that applies for the next regulatory period.

Within-period demand risk is a more material issue for gas transmission than distribution. This is because large, single customers and sites have a greater impact on total revenue – and their decisions can therefore have a larger impact on a supplier's ability to earn its allowed revenues. The Commission carefully considered the allocation of transmission demand risk at the last IMs review and decided to apply a pure revenue cap – recognising that Firstgas has little or no control over the decisions of gas users that operate in global commodity markets.

We believe that the reasoning the Commission applied at the last IMs review continues to apply and is strengthened by the experience gained over the current regulatory period. One the one hand, we have seen Refining NZ recently announce plans to significantly curtail or cease using gas. This decision was made in the same regulatory period that Refining NZ funded an expansion to the gas transmission system to enhance gas deliveries to its Marsden Point site. At the other end of the spectrum, NZ Steel has faced very challenging operating conditions over the past five years but is

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[17] Our full work programme is presented on www.gasischanging.co.nz

[18] Details on stakeholder feedback received at the Firstgas webinar is outlined in our 2021 Asset Management Plan Updates available on our website here: https://firstgas.co.nz/about-us/regulatory/

[19] Paragraph 3.43.3, Process and Issues paper.

currently realising record prices for its steel production (and by implication maximising the value of their gas use). In both cases, it would be highly inefficient for Firstgas to attempt to influence the decisions of these gas users and providing incentives to do so under the regulatory regime would almost certainly result in inefficient outcomes.

There is a more arguable case for changing the form of control for gas distribution since the current weighted average price cap appears at odds with the direction of Government policy to decrease reliance on natural gas. However, we consider that the current price cap is unlikely to have a material impact on supplier behaviour over the next regulatory period. As set out in this submission, the long-term nature of investment in gas pipeline infrastructure means that risks around future capital recovery have far more influence on supplier decision-making than any near-term profitability that comes from outperforming demand forecasts.

We acknowledge that it will be difficult for the Commission to forecast demand for distribution services over the DPP3 period, given current policy uncertainty. However, we expect that this challenge is not insurmountable. We do not expect massive shifts in gas distribution demand over the next four years given that specific policy measures have not yet been confirmed and will take some time to be implemented. It may therefore be practical for the Commission to simply forecast stable demand over the coming DPP3 period (i.e., constant price revenue growth of 0%).

Given the materiality and impact of other issues, we do not consider that changes to form of control for either the GTB or GDB should be advanced at the DPP3 reset.

5. Mechanics of the DPP reset

The Commission raises several options for the DPP reset that may better fit with the current circumstances – including rolling over existing prices or using top-down expenditure forecasts. We agree that it is worth carefully considering how to reset prices in a way that best reflects the ongoing uncertainty and enables the available resources to have the most beneficial impact.

<u>Rolling over prices versus a building blocks approach</u>

The Commission suggests that it could make sense to simply roll over existing prices at the DPP3 reset, rather than resetting prices based on a building blocks analysis[20] of current and future profitability. This approach has some practical appeal – since it would remove the need for analytical steps that involve wide bands of uncertainty and may not be fit for purpose (such as estimating the current cost of capital before the IMs review).

Rather than leading to higher prices (as suggested by the Commission),[21] our analysis suggests that rolling over current prices would lead to lower prices than a building blocks analysis. This is mainly due to two factors:

- Forecast increases in the risk-free rate between now and the DPP reset mean that the WACC estimate is likely to be closer to the current DPP WACC than previously expected
- The capital recovery mechanisms discussed above (non-indexation of RABs and accelerated depreciation) would more than offset any fall in WACC.

As a result, our preference is for the Commission to use a building blocks financial model for the DPP3 reset, combined with suitable adjustments that accelerate capital recovery.

However, we acknowledge that the focus on capital recovery IMs changes may mean that the usual DPP processes and models are not able to be implemented. If this is the case, we accept that a

[20] The Building Blocks Allowable Revenue (BBAR) approach set out in Figure 4.1 of the Process and Issues Paper.

[21] Paragraph X15, Process and Issues paper.

roll-over could be considered – although we would need to understand how the Commission could ensure that any resulting revenue shortfall does not itself undermine financial capital maintenance.

<u>We support the use of a 4-year regulatory control period</u>

Firstgas supports the setting of a four-year regulatory period for this DPP reset,[22] rather than the standard five-year regulatory period. This option will provide time for the Commission to complete the full IMs review process (by December 2023), for greater policy direction to emerge from the Government's response to the Climate Change Commission's final report (December 2021) and for the National Energy Strategy to be completed (expected June 2024).

These work programmes and milestones will provide greater clarity of direction for the next regulatory period for GPBs and will enable the Commission to apply the updated IMs to GPBs from 1 October 2026. It is also a pragmatic solution, particularly if the timeframe for DPP3 reset and uncertainty prevents the Commission from making all the necessary amendments required to get the regulatory settings right for DPP3.

<u>Top-down expenditure forecasts (versus AMP scrutiny)</u>

If the Commission applies a building blocks approach to the DPP3 reset, we support the use of top-down expenditure forecasts rather than scrutinising expenditure forecasts in AMPs. We believe this is a pragmatic approach given the resources and time available for the DPP reset. Given the reasons we have outlined above, we consider that effort should focused on getting the IMs right for capital recovery.

We note that while top-down expenditure forecasts may not capture the growing expenditure needs for hydrogen trials and biogas injection, past expenditures will provide the Commission with a reasonable guide to the safety and reliability (business as usual) expenditure required by GPBs.

<u>Quality standards</u>

Firstgas supports the Commission's view that no additional quality standards are necessary for DPP3.[23] Our engagement with transmission customers indicates that they still place a high value on transmission reliability, and they are generally not prepared to trade off lower levels of reliability for lower prices.

As outlined in the paper, the Commission introduced the "major interruptions" quality standard for our GTB in the last DPP reset in 2017. We consider that this quality standard reflects the importance customers place on a continuous supply of natural gas and remains an appropriate standard for DPP3. We believe no amendments are required to its drafting or definitions, as this quality standard utilises the definitions well-established under the *Gas Governance (Critical Contingency Management) Regulations 2008.*

We also believe the drafting improvements made in DPP2 discussed in the paper[24] have ensured that the quality standards for both our GDB and GTB remain practical to monitor and report against. Given the lack of issues with existing quality standards, we do not see the need for the Commission to prioritise additional investigation here.

[22] As enabled by sections 53M (4) and (5) of the *Commerce Act 1986*.

[23] Page 10 and paragraph C25 of the Process and Issues paper.

[24] Paragraphs C14 – C18 of the Process and Issues paper.

6. Recommendations for the DPP3 reset process

In terms of process, we believe that it is essential for the Commission to decide on the focus areas and reset mechanics approach that it intends to take for the DPP reset as soon as possible. We would expect the Commission to be in a position to decide whether to roll-over current prices or apply a building blocks approach by the end of October 2021. This decision will enable all parties to focus their efforts on the issues that will be addressed in the DPP3 reset and what refinements are needed to the processes to scrutinise expenditure (if applicable).

Schedule workshop on capital recovery IMs changes

The Commission has indicated that it may hold issue-specific workshops following submissions and cross-submissions on the paper and has welcomed suggestions for topics that merit further discussion.[25] Firstgas supports the use of workshops to flesh out issues and debate the best process for the DPP reset. We believe that the inclusion of workshops provides for a more robust consultation process that can elicit detailed insight from GPBs, customers and broader stakeholders who have insight on the gas sector.

We recommend that the Commission hold a workshop on capital recovery options early in the DPP3 reset process (ideally October 2021). As we have outlined in the sections above, we believe this is the most pressing issue that must be addressed in this DPP reset and an early workshop on this topic would help inform any IMs amendments.

Recommended next steps

Table 1 set outs the tasks that Firstgas recommend are undertaken prior to the Commission determining the final decision for DPP3. We consider that these additional tasks fit within the Commission's indicative timeframe,[26] and would enable the Commission to meet the section 52V consultation requirements around introducing IMs amendments for a DPP reset. We believe it is possible for the Commission to consult on draft IMs amendments before Christmas 2021, while still meeting its February 2022 timeframe for releasing its draft decision.

Table 1: Recommended steps in DPP3 reset process (additions shown in blue)

Date	Key decision, process, or publication
30 August 2021	Submissions on Process and Issues paper
13 September 2021	Cross-submission on Process and Issues paper
October 2021	**Formal notification of approach to be applied in DPP3 reset**
By end October 2021	**Workshop(s) on managing capital recovery risk**
November 2021	**Publish paper on draft IM amendments (as per section 52V)**
Early December 2021	**Workshop on draft IM amendments (option under section 52V)**
Mid-December 2021	**Submissions due on proposed IM amendments**
10 February 2022	Draft decision **and final decision on IMs amendments**
11 March 2022	Submissions on draft decision
25 March 2022	Cross-submissions on draft decision
31 May 2022	Final decision

[25] Paragraphs 7.3 – 7.4 of the Process and Issues paper.

[26] As set out in Table 7.1 of the Process and Issues paper.

Contact details

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Yours sincerely

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Attachment 1: Evaluation of the best approach to the DPP3 reset

Our evaluation of the options for the DPP3 reset is set out in Table 2. The options have been grouped into four broad themes: capital recovery mechanisms, DPP3 reset mechanics, mechanisms for allocating within period demand risk and other changes. We have considered the options relative to the approaches used for the 2017 DPP reset for GPBs.

Items in *italics* are suggestions made by stakeholders that have not been considered by the Commission in its Process and Issuespaper, but we believe should remain in consideration for the DPP3 reset.

Table 2: Evaluating the process and issues for the DPP3 reset

Regulatory approach (cf 2017 approach)	Reduce risk of future price escalation / asset stranding	Provide sufficient incentives to maintain safety and reliability s52A(1)(a)	Preserve option of repurposing gas infrastructure	Practicality of implementation (reduce compliance costs and complexity)
Capital recovery mechanisms				
Removing RAB indexation (Indexing RAB by CPI and treating income as regulated revenue)	✓ Frontloads cash flows which reduces future price increases	✓ Provides greater assurance of cost recovery on new ARR expenditure	✓ Reduces RAB to be recovered from future consumers, who are likely to pay higher gas prices (e.g., biogas, hydrogen). Provides near term cash flows to fund investment	✓ Seems easy given that Transpower IMs already incorporate a non-indexed RAB. Circumstances seem more appropriate for GPBs than Transpower. We understand this require a change to the asset valuation IMs
Accelerating depreciation (Standard straight-line depreciation based on technical asset lives)	✓ Frontloads cash flows which reduces future price increases	✓ Provides greater assurance of cost recovery on new ARR expenditure	✓ Reduces RAB to be recovered from future consumers, who are likely to pay higher gas prices (e.g., biogas, hydrogen). Provides near term cash flows to fund investment	✓ Simplest approach to carry over 15% acceleration option from EDB IMs (although this may not be sufficient over the longer term in the gas industry given specific risks). Not practical to have application process Requires IMs change

Regulatory approach (cf 2017 approach)	Reduce risk of future price escalation / asset stranding	Provide sufficient incentives to maintain safety and reliability s52A(1)(a)	Preserve option of repurposing gas infrastructure	Practicality of implementation (reduce compliance costs and complexity)
Ex-ante compensation for stranding risk (No adjustment for stranding risk)	✗	✓ Improves risk / reward balance for new investments	✓ Provides near term cash flows to fund investment	✓ Analytical framework and approach already developed for fibre. But gas specific estimation issues may be challenging. Does not require IMs change
DPP reset mechanisms				
Rolling over prices (Estimating building block components)	✗ Our analysis suggests that building blocks prices (with appropriate IMs changes) would increase prices and therefore lessen future price rises	--- Provides near term certainty but doesn't materially affect economics of new investment	--- Unlikely to have a material effect on repurposing decisions	✓ Acknowledges difficulties in accurately estimating building blocks. Pragmatic
4-year regulatory period (5-year regulatory period)	--- Reduction in time doesn't materially affect this risk (since it only brings next reset forward by 12 months)	--- Allows time to complete substantive IMs review to consider the issue, but does not address the risk during the period	✓ Shorter period still provides time to complete National Energy Strategy mid-2024	✓ Pragmatic solution, particularly if timeframe for the review and uncertainty prevents Commission from making all changes required to get the regulatory settings right this time around
Using top-down expenditure forecasts (Scrutiny of AMP Opex and Capex forecasts)	--- Change in forecasting approach unlikely to change long term prospects for capital recovery	✓ Past expenditures provide a reasonable guide to safety and reliability expenditure	✗ Unlikely to capture growing expenditure needs for hydrogen trials and biogas injection	✓ Pragmatic since the effort that would be put into scrutinising forecasts would be better put into getting IMs right.

Regulatory approach (cf 2017 approach)	Reduce risk of future price escalation / asset stranding	Provide sufficient incentives to maintain safety and reliability s52A(1)(a)	Preserve option of repurposing gas infrastructure	Practicality of implementation (reduce compliance costs and complexity)
Applying a productivity factor (No X factor applied)	--- Unlikely to have a material effect	--- Does not affect investment incentives	--- Does not affect innovation / repurposing	✗ Effort that would be put into estimating productivity factor would be better put into getting IMs right
Changing quality measures (RTE for all GPBs and major interruption standard for GTB)	--- Reductions in quality standards could reduce risk of price increases, but feels too soon to bear additional risk	--- Depends on how quality measures are changed	--- No change	✗ Doesn't seem like the right focus for this DPP review
Mechanisms to allocate within period demand risk				
Reviewing form of control (GDB) (Weighted average price cap for GDBs)	--- Minor improvement	--- No change	--- No change	✓ Would avoid having to forecast distribution demand given uncertainty. However, resources better put solving other issues (like capital recovery)
Reviewing form of control (GTB) (Pure revenue cap for GTB)	--- Does not materially change price and stranding risk	✗ Creates additional cost recovery risk within period for transmission investments	✗ Could create significant cost recovery issues that prevent repurposing due to lack of funding	✗ Major challenge to forecast demand for transmission. Wrong risk allocation
Adopting an EV account for GTB (Annual wash-up of under- or over-recovered revenue)	✓ Creates greater price stability within period. No change overall'=	--- No change	--- No change	✓ Existing regulatory rules for Transpower EV account can be carried across

Regulatory approach (cf 2017 approach)	Reduce risk of future price escalation / asset stranding	Provide sufficient incentives to maintain safety and reliability s52A(1)(a)	Preserve option of repurposing gas infrastructure	Practicality of implementation (reduce compliance costs and complexity)
Other changes to mechanisms				
Adding IRIS mechanism (No IRIS for GPBs)	✗ Would introduce new source of uncertainty for GPBs in transition	✗ Would introduce new source of uncertainty for GPBs in transition	--- Unlikely to have an impact on repurposing investments	✗ Almost certainly not worth the time and effort given that bigger incentives will drive investment and efficiency than cash flow timing
Adjusting TAMRP (Estimated market risk premium of 7%)	--- Very minor impact in increasing prices now (offsetting future price rises)	✓ Updated view on cost of capital better aligns with costs of safety and reliability expenditure	✓ Provides additional near-term cash flow to position for repurposing	✓ Simple to carry over. Decision already made for fibre
Introduce innovation allowance	--- Would only make a difference to stranding risk if allowance was significant	--- No link to reliability and safety investment	✓ Provides explicit recognition of the value of innovation and preparing for repurposing and some additional cash flow	✓ Relatively simple given allowance already incorporated into EDB DPP reset. Amount of allowance unlikely to make a difference