NZ Gas Infrastructure Future

Initial Analysis Paper

The New Zealand government is looking to take decisive action to address climate change – and this will have a profound impact on the use of natural gas.

A working group was established in May 2021 to consider the potential impacts from a gas infrastructure perspective.

This Initial Analysis Paper reports on work commenced in October 2021 to provide more detailed conceptual quantitative and qualitative analysis to inform policy and regulatory decisions related to the future of gas infrastructure.

14 March 2022

Note: the paper was developed without consideration of the Commerce Commission's recent draft decision on the default price paths for gas pipeline businesses. The working group may undertake further analysis in light of that decision.

Contents

NZ Gas Infrastructure Future

EXECUTIVE SUMMARY

This Initial Analysis Paper reports on work commencing in October 2021 to provide more detailed conceptual quantitative and qualitative analysis to inform policy and regulatory decisions related to the future of gas infrastructure.

The work involved development of a conceptual financial model and model inputs – including demand, pricing and expenditure assumptions – to enable analysis of the potential impacts on gas consumers, gas infrastructure businesses, and Government over a 35 year horizon.

The conceptual analysis considers alternative scenarios that build on the two developed in the Findings Report, namely, gas infrastructure winddown and repurposing. The paper was prepared without consideration of the Commerce Commission's recently published draft decision on the default price paths (DPPs) for gas pipeline businesses (GPBs).

This initial analysis is preliminary and conceptual. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes that will be more dynamic and responsive than can be reflected through modelling. Nor does this analysis seek to assess the financial performance or position of any specific gas pipeline business. The analysis conclusions should be read together with the relevant qualifications and caveats. The analysis should not be attributed to individual participants in the working group, nor those that have helped the working group prepare it.

The analysis presents results and makes preliminary findings on five interrelated questions:

Question 1 | *What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?*

Cost recovery risk is the risk that gas infrastructure owners cannot recover the efficient costs incurred to provide gas transmission and distribution services.

The focus of this analysis is on cost recovery risk linked to Government action on climate change. Cost recovery risk raises questions about the ongoing willingness and ability of gas infrastructure owners and lenders to continue investing in the infrastructure that supports those services.

The initial analysis shows:

- Infrastructure owners are exposed to potential material cost recovery risk of **$948 million** in present value terms ($2021) in unrecovered revenue and residual unrecovered capital if gas infrastructure is wound down by 2050 and **$1,222 million** if it occurs by 2040, *assuming* no regulatory or policy levers (or mitigations) are applied.

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This Initial Analysis Paper builds on the earlier Findings Report by taking an initial – and preliminary – look at potential future outcomes. Care should be taken when interpreting the results.

A winddown of regulated gas pipelines exposes gas infrastructure owners to material cost recovery risk of between **$948 million to $1,222** million.

- Notwithstanding modelling limitations, it appears there is no doubt that under both fast and slow winddown scenarios – and under all sensitivities tested – that cost recovery risk will occur with the modelling uncertainties being about the speed with which this risk will crystallise and the magnitude of it.
- Although alternative assumptions (e.g., as to the ability to recover allowed revenue) will affect that risk, current regulatory settings (e.g., depreciation of long-lived assets) – if maintained – will lead to sizable unrecovered capital if pipelines no longer service gas consumers in a winddown scenario.

Question 2 | *How is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners affected by the potential for re-purposing and differences in willingness to pay across customer classes?*

- Re-purposing gas infrastructure could reduce cost recovery risk because it would extend the useful life of a portion of existing and future infrastructure by allowing gas infrastructure owners to continue as a going concern.
- However, the extent of any re-purposing – and therefore any reduction in cost recovery risk – will depend on the potential revenue that could be recovered from gas demand that remains relative to the costs of re-purposing. If incremental costs from repurposing can be recovered from incremental revenue over an appropriate timeframe, then it may be sensible to pursue re-purposing.
- Further analysis is needed to better understand this dynamic, including as to the difference in cost between green gas and alternative energy sources and what this means for willingness to pay.

The optimistic and pessimistic scenarios modelled are based on assumptions including the potential for piped hydrogen to become competitive with electricity and other alternative energy sources, about which there is debate – these assumptions affect the conclusions that can be made.

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Re-purposing gas infrastructure could reduce that risk.

However, whether re-purposing is realistic or not will depend on whether expected revenue from gas consumers that remain is sufficient to cover the costs of re-purposing and continuing to run the pipelines.

Question 3 | *What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?*

- Financial viability of GPBs appears at risk under all modelled scenarios, assuming no change to current regulatory settings or Government intervention. This will raise questions about the willingness and ability of shareholders to keep investing.
- Key drivers of the size of this risk are gas consumers' future demand and willingness to pay for gas transportation services, which largely drives GPBs' net cash flows.
- Cash flow and return on investment (ROI) projections suggest that changes will need to be made to regulatory and policy settings for gas pipelines to remain financially viable under a winddown scenario.
- Faced with that outlook it may be rational for gas infrastructure owners to shutdown uneconomic sections of their infrastructure sooner than is socially desirable. If shutdown did occur, then energy consumers would lose the option to choose reticulated gas as an energy source. The option of repurposing existing gas infrastructure for lower carbon fuels would also be foreclosed.
- Further work could be undertaken to better understand the drivers of the cash flow projections under both winddown and repurposing scenarios, including as to what revenue gas infrastructure owners may be able to realise from gas consumers and what mitigations could be taken (e.g., changes to regulatory settings or offset the risk faced).

Question 4: *What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?*

- A winddown of gas pipelines exposes the remaining gas consumers to meaningful price increases as other consumers defect up until the infrastructure is shutdown. After that point, consumers lose the choice to consume reticulated gas to meet their energy needs.
- The pace of the winddown will clearly affect that risk – with a faster winddown leading to faster price increases that will encourage more rapid defection of consumers through the winddown.
- Repurposing gas infrastructure may help reduce that risk, although further work is needed to better understand what demand may look like under such a scenario.

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Financial viability of GPBs appears at risk under either a fast winddown or optimistic repurposing scenario.

A winddown of gas pipelines exposes the remaining gas consumers to meaningful price increases as other consumers defect - The pace of the winddown clearly affects that risk.

Question 5 | *How could the implications for gas infrastructure owners and consumers be affected by future policy and regulatory decisions? What impact could different levers have (e.g., regulatory settings, government support)?*

For the initial analysis, 6 government and regulatory policy 'levers' were tested separately (i.e., not combining levers). These are a subset of the 35 potential solutions identified in the Solutions Scoping Paper that the working group finalised in November 2021.

From the perspective of **gas infrastructure owners**:

- **Levers 1 and 2** | *Accelerated depreciation, Asset stranding allowance* | both levers increase the present value of cash flows, although there is a partial offset later over the period if accelerated depreciation is used (as the RAB is lower). Accelerating depreciation reduces the RAB, while an ex ante allowance has no effect.
- **Lever** 3 | *RAB indexation is removed* | this lever increases cash flows in earlier years and reduces it in later years, with the net effect being positive under the assumptions modelled.
- **Lever 4** | *Government acquisition of 50% regulatory asset bases (RABs)* | this lever gives a substantial positive cash inflow early in the modelling period, which is offset by lower cash flows over the remainder of the period (as the RAB is lower) – the net impact appears to be negative in present value terms under both the fast winddown and optimistic repurposing scenarios modelled, however, it is likely that the conclusion will differ if demand were to adjust (e.g., from lower prices) or if a higher discount rate was used.
- **Lever 5** | *Government subsidises green gas (50% of the wholesale green gas costs incurred by gas consumers)* | this lever has only an indirect impact on cash flows and does not affect the RAB at all – under the optimistic repurposing scenario it leads to an increase in cash flows to both transmission and distribution as customers willingness to pay for gas transportation services increases (as gas consumers need to pay less on wholesale costs).
- **Lever 6** | *Removing price or revenue caps* | this lever increases cash flows, especially for distribution pipeline businesses, but does not affect the RAB.

Gas consumers will benefit to the extent that the levers improve the prospect that gas infrastructure remains financially viable – as they retain the choice to consume reticulated gas. However, gas consumers will be affected differently by the lever or levers adopting under the alternative scenarios. For instance:

- **Under fast winddown scenario** | no lever appears to avoid the base case projection that regulated annual charges will increase exponentially as demand falls to zero by 2040, except where price and revenue caps are removed.
- **Under optimistic re-purposing scenario** | for all levers, charges are projected to increase gradually over time in nominal terms, without any exponential growth. This is because GPBs are assumed to continue as a going concern with demand to pay for allowed revenues.

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Six government and regulatory policy 'levers' were tested.

Analysis suggests that those levers can positively affect the outcomes faced by gas infrastructure owners.

Gas consumers will benefit if infrastructure remains viable as they will otherwise lose the choice to consumer reticulated gas.

Levers will affect the charges faced by gas consumers differently.

1. INTRODUCTION

The New Zealand Government is committed to taking decisive action to address climate change. A carefully managed transition will be required to ensure continuity of a safe, reliable, and affordable energy supply as gas and LPG consumers transition their consumption to zero carbon 'green gases' or alternative renewable energy sources.

The Gas Infrastructure Future Working Group[1] (Working Group) was established in May 2021 to offer constructive input to the Government's response to the Climate Change Commission advice with a focus on the future of gas infrastructure in New Zealand.

The Working Group has delivered:

- an initial **Findings Report** to the Minister of Energy and Resources in August 2021,[2] which was undertaken over a short period to provide a starting point for policy development and dialogue between the Government and affected stakeholders.
- a **Solutions Scoping Paper** published in November 2021, which builds on the Findings Report by identifying a broader range of potential solutions that could be adopted – in combination – to address those challenges over the short, medium, and longer term.

This **Initial Analysis Paper** builds on this earlier work. It seeks to provide more detailed, albeit conceptual, quantitative and qualitative analysis to inform policy and regulatory decisions related to the future of gas infrastructure. It is not intended to inform business or consumer decisions.

It reports on the outcomes of a simplified model and inputs – including demand, pricing and expenditure assumptions – developed to analyse the potential impacts on gas consumers, gas infrastructure businesses, and Government over a 35 year horizon under alternative scenarios. In doing so, it extends from the winddown and re-purposing scenarios considered in the initial Findings Report.

The working group's initial analysis is preliminary, conceptual, and will likely evolve. The initial conclusions should be read together with the relevant qualifications and caveats. The analysis should not be attributed to individual participants in the working group, nor used to inform financial or commercial decisions.

The initial analysis was prepared before the Commerce Commission published its draft DPP decision for GPBs, and so does not consider the impacts of that decision. The working group will consider that decision further any may undertake further analysis in response.

The rest of this paper is structured as follows:

- **Section 2** sets out the context and analysis framework for this analysis
- **Section 3** describes the model, the scenarios and sensitivities and limitations
- **Section 4** reports on the initial analysis, and
- **Section 5** considers further analysis that the working group – or others – could explore.

1 See Solutions Scoping Paper, Appendix B for the updated Working Group Charter and membership.

2 Gas Infrastructure Future Working Group, *New Zealand Gas Infrastructure Future Findings Report*, August 2021.

2. CONTEXT AND ANALYSIS FRAMEWORK

2.1. Summary

Gas pipeline infrastructure is expected be used less – or differently – in the future due to the impact of Government climate change policies. The potential exists to repurpose gas infrastructure in a way that supports those policies but the evolution of a market for green gases in New Zealand is far from certain.

The initial analysis undertaken by the working group considers questions around cost recovery risk; the impact of re-purposing; the implications for infrastructure owners; the implications for consumers; and the impact that different policy and regulatory settings could have in addressing these implications.

2.2. Context

Previous work undertaken by the working groups indicates that gas pipeline infrastructure will be used less in the future due to the impact of Government climate change policies, but there is potential to repurpose gas infrastructure in a way that supports those policies.

The expected decline in pipeline utilisation will affect both current and future gas consumers as well as gas infrastructure businesses. Lower pipeline usage will likely create challenges for consumers from higher gas transportation charges to ensure that gas pipeline business remain viable while they continue to operate.

Broadly, natural gas infrastructure faces two future scenarios:

- **Infrastructure winddown** | where gas consumption is fully phased out and gas pipelines are decommissioned in a safe and orderly way, and all consumers switch to other zero (or low) carbon energy sources, and
- **Infrastructure re-purposing** | where gas consumption transitions from natural gas to 'green gasses' (most likely hydrogen, biomethane or some blend of these) and some or all existing pipelines are repurposed to deliver these green gasses to consumers.

Gas consumers will need to progressively switch to alternative zero carbon energy sources[3] including electricity and – under a re-purposing scenario – potentially to green gases such as hydrogen or biomethane. This switching process will likely create conversion cost impacts for consumers. However, it may also involve new gas consumers, such as those that may switch to hydrogen to power their vehicles.

2.3. Analysis scope

Consistent with standard economic regulation approaches, the scope of the initial conceptual analysis undertaken in the Initial Analysis Paper considers only private costs and benefits to gas pipeline owners and consumers under winddown or re-purposing scenarios. No account is taken of externalities – such as spill over costs and benefits – that would be considered in a broader social cost benefit analysis.[4,5] Whether or not broader social costs and benefits should be assessed could be considered further in future.

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3 Both scenarios assume that use of natural gas is fully phased out. The possibility that there might be some residual use of natural gas for some limited high value purposes with associated emissions mitigated through carbon offsets could be an area to explore in future.

4 See NZ Treasury, Guide to Social Cost Benefit Analysis, 27 July 2015 https://www.treasury.govt.nz/publications/guide/guide-social-cost-benefit-analysis

5 Possible examples of externalities that could be considered in a social cost benefit include for example: the environmental, amenity and safety benefits of distributing green gasses by way of pipelines compared to, say, by road; avoidance of amenity disbenefits arising from the decommissioning of pipelines, changes in security of energy supply, and so on.

2.4. Analysis questions

This Initial Analysis Paper considers the following questions:

1. **Cost recovery risk |** *What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?*

2. **Impact of re-purposing |** *How is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners affected by the potential for re-purposing and differences in willingness to pay across customer classes?*

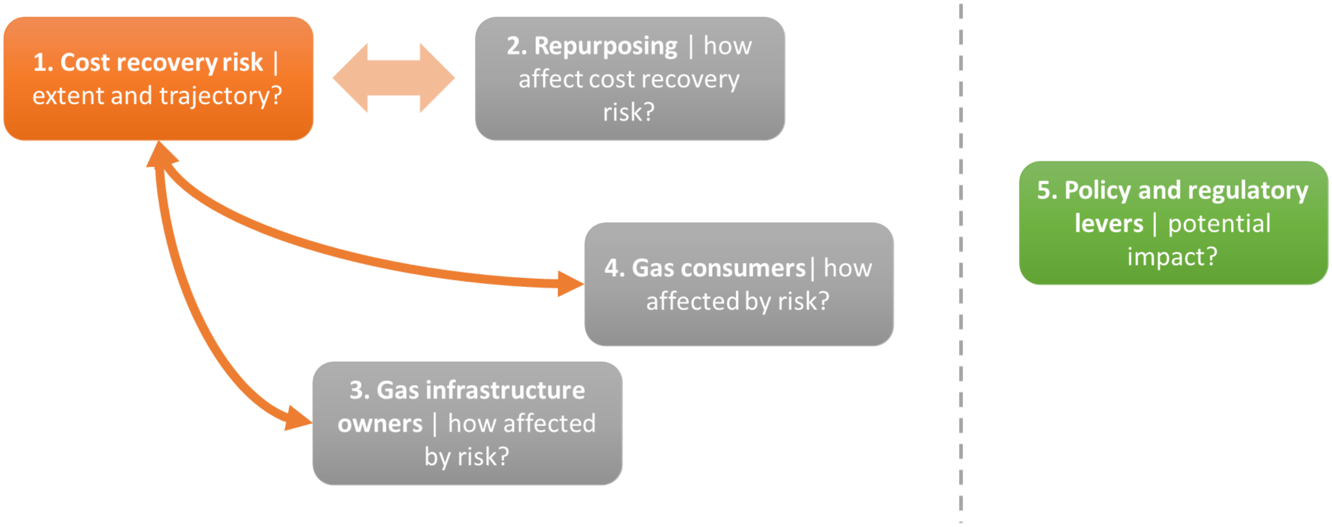
3. **Implications for infrastructure owners |** *What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?*

4. **Implications for consumers |** *What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?*

5. **Policy and regulatory levers |** *How could the implications for gas infrastructure owners and consumers be affected by future policy and regulatory decisions? What impact could different levers have (e.g., regulatory settings, government support)?*

Figure 4.1 sets out these analysis questions and the relationship between them.

FIGURE 2.1: ANALYSIS QUESTIONS



2.5. Definition of key analysis concepts

Definition of key concepts considers in the analysis are set out in **Box 1**.

Box 1 : Key analysis concepts | definitions

Cost recovery risk | the risk that gas infrastructure owners cannot recover the efficient costs incurred to provide gas transmission and distribution services. This risk can be affected by Government action, regulatory decisions, and market changes. Although cost recovery risk may also occur due to changes in market conditions (e.g., due to technology advances or consumer preference changes), the focus of this analysis is on cost recovery risk linked to Government action on climate change.

Re-purposing of pipeline infrastructure | actions, expenditure and avoided expenditures (including decommissioning) to enable pipelines to transport green gases (such as hydrogen and biogas).

Financial viability | the ability of an organisation to meet its ongoing financial obligations as well as expected future investment and operating needs.

Regulatory and policy options | includes a broad range of solutions, or levers, that could be adopted by the Government, the Commerce Commission, gas infrastructure owners, or others to mitigate or avoid adverse implications. The Solutions Scoping Paper prepared by the working group recently identified 35 such solutions.

2.6. Model development

To explore the five analysis questions, the working group developed an Excel cash flow model that assesses the impacts on gas consumers and gas infrastructure owners of alternative scenarios, and regulatory or policy levers.

The steps involved were:

- **Model developed** – with support from PwC, the working group develop the model to analyse the five initial questions
- **Model populated** – drawing from input from Concept Consulting and the gas infrastructure owners, initial inputs to the model were generated that aligned with the various scenarios that the working group sought to assess, including demand and price projections and expenditure forecasts
- **Model refined** – after an initial review of the inputs and outputs, key model inputs and assumptions were further refined to better reflect real world expectations
- **Model outputs analysed** – the model outputs (e.g., charts and present values) were analysed and used to prepare the initial analysis discussed in section 4.

As this is only an initial analysis, the working group expects to undertake further work refining the model (and inputs or assumptions to it) and to use it to assess other questions.

Section 2.7 below describes in further detail how the modeling was developed undertaken.

2.7. How the analysis was planned and developed

Box 2 describes how the analysis was planned and developed.

Box 2: How the analysis was planned and developed

The working group developed a model scope that provides for:

- Working Group members, participants, or other stakeholders to be able, if they wish to further refine and develop the Model after its initial development
- Facilitation of peer review if required.

Following a competitive selection process the working group engaged PricewaterhouseCoopers New Zealand (PwC) to help design and build the model.

Concept Consulting was engaged to produce indicative pipeline demand projections and associated consumer prices (for pipeline gas, and alternatives to pipeline gas) for the defined scenarios. As would be expected given the complex nature of demand and pricing dynamics, questions remain over how realistic these projections are (see discussion in section 2.8.1).

A modelling subgroup comprising representatives from each of the gas pipeline business was established to enable discussion with PwC on the model structure, design, and development.

The gas pipeline businesses completed templates provided by PwC setting out expenditure forecasts consistent with each of the scenarios.

PwC then populated the model with expenditure and demand input data, performed sense checks on outputs, and performed a full review of model logic and quality assurance checks.

This work was then considered by the working group and further refined.

2.8. Key questions not addressed in the modelling

At the outset, it is worth noting that this *Initial Analysis Paper* – and the modelling underpinning it – has only scratched the surface of the questions being considered by the working group.

These section highlights two of those questions that emerged:

- What is the viability of infrastructure re-purposing?
- How do differences between transmission and distribution sectors affect their prospect?

These questions are discussed briefly below. The working group may consider looking at these further in future analysis.

2.8.1. Viability of re-purposing scenarios

An important question raised when preparing pipeline demand projections and associated consumer prices was the plausibility of pipeline re-purposing emerging based on a significant adoption of hydrogen. (Details are set out in section 2.8.2 below and in the Appendix).

Concept Consulting analysis – based on current expected economics of future energy costs – suggested that it was not plausible for hydrogen to become competitive with electricity for a sufficiently large range of end uses in a way that would support transportation of hydrogen by gas pipelines.

Some in the working group considered that given significant future uncertainty over the prospects for hydrogen technology development – reflecting major global investment in hydrogen – that a hydrogen re-purposing future should not be ruled out. Although it is implicit in the re-purposing scenarios modelled that hydrogen and other green gases are assumed to be transported, the working group has not reached conclusions on whether that assumption is realistic or not. The working group is undertaking further work to explore this question in more detail. Any conclusions are unlikely to be definitive for several years and also depend on international developments in technologies and business models.

2.8.2. Differences between the transmission and distribution sectors

Another question raised when preparing the analysis was how do differences between transmission and distribution sectors affect their respective prospects.

Transmission and distribution sectors have different features and roles in the gas supply chain. In brief,[6] the transmission pipeline takes gas from producing fields in Taranaki and transports it to gas distribution networks, industrial facilities – such as dairy processors, steel mills, wood processors – and electricity generators. The distribution pipelines then transport gas from the gas transmission pipeline to smaller industrial, residential and commercial consumers.

As discussed in section 3 and Appendix A, the initial analysis undertaken by the working group distinguishes between the gas transmission network of Firstgas and the gas distribution networks of Vector, Powerco, Firstgas, and GasNet. Current asset values, revenue, demand, and other inputs were used for each network, as were projected expenditure requirements and future demand, with demand for gas distribution services forming a component of demand for gas transmission services.

Customer groups differ between transmission and distribution networks, and the distribution of customers across customer groups differs between individual gas distribution networks. This means that the modelled consumption dynamics under different scenarios can differ strongly between the transmission and distribution sectors, and some differences also exist between gas distribution networks.

Although these modelled differences allowed the working group to understand how the prospects of the gas transmission and distribution sectors may differ, it was by no means exhaustive. There may be different future scenarios for the two sectors that that lead to significantly different outcomes for transmission and distribution pipelines. For instance,

- **Distributed green gas production scenario** | in this scenario, green gases (hydrogen, biogas) would be produced close to demand centers, with any required bulk transport of energy being provided by geographically co-located electricity networks. This could result in some continued utilisation of re-purposed distribution networks and a winddown or more limited use of the gas transmission network, such as for network balancing and security of supply only.
- **Bulk transport system scenario**| in this scenario, there would be a system providing bulk transport of green gasses through a repurposed transmission system to certain industrial facilities, electricity generators, new green gas transport fueling facilities, and potentially localised gas storage facilities. This scenario could see re-purposing of the transmission pipeline network, but with limited or no future role for the distribution network and with residential and commercial consumers shifting to electricity.
- **Small customer defection** | in this scenario, the relative costs of using natural or green costs exceed those of alternative energy sources for most small customers, leading to large defection from – and eventual winddown of – the gas distribution networks. At the same time, a higher willingness to pay and a lack of alternative energy sources leads most large industrial customers to remain connected to gas transmission network. The net result is distribution networks winddown but the transmission network is re-purposed and remains operating.

Further work could be undertaken to better understand how these scenarios may affect the future of gas infrastructure in New Zealand.

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6 See section 2.1 of the Findings Report for more detail on the industry structure. NZ Gas Futures Infrastructure Working Group, Findings Report, 13 August 2021.

3. MODEL DESCRIPTION

3.1. Summary

Core to the initial analysis undertaken by the working group is an Excel model that assess the potential financial impact on gas consumers and gas infrastructure owners of future scenarios for gas infrastructure in New Zealand.

The working group used this model to test how alternative scenarios – and policy and regulatory levers – may affect outcomes faced by gas consumers and infrastructure owners.

The model is summarised in the next few sections. A more detailed description of the model is set out in **Appendix A**.

3.2. Model

The model contains two core modules:

- a building blocks allowable revenue (BBAR) module that projects the revenue that gas pipeline businesses are allowed to recover *assuming* that economic regulation continues to apply
- a consumer impacts module that projects the annual revenue recovered from gas consumers.

Outputs from these modules is used to project net cash flows and proxy credit measures for gas infrastructure owners, and costs or prices faced by gas consumers.

To drive these two modules, the model relies on projected demand, wholesale gas prices, alternative energy prices, energy conversion costs, pipeline capital and operating expenditure, and other inputs, including those needed for the BBAR calculations (e.g., weighted average cost of capital (WACC), inflation, asset lives). It also relies on current regulatory inputs, such as the regulatory asset base (RAB) values for each regulated gas pipeline business.

3.3. Scenarios and sensitivities

A key capability of the model is the flexibility to test alternative scenarios and sensitivities, including:

- **Market scenarios** – which are four[7] defined scenarios relating to the overall market outcomes for gas, including 2 winddown scenarios (fast and slow) and 2 re-purposing scenarios (optimistic, pessimistic)[8]
- **Model scenarios** – which are five customisable scenarios used to test a range of regulatory and policy levers (and other factors).

The initial analysis considered in section 4 was developed using different combinations of these scenarios.

The four market scenarios are described in Table 3.1.

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7 Note that early work considered two other market scenarios. For simplicity, this paper does not present results for these but the results are available. These other market scenarios are: (E) Capital light market scenario, and (F) Reproposing Pivot (which assumes a slow wind-down scenaROI for the first 10 years, then pivot to the pessimistic hydrogen repurposing scenario).

8 The Model also includes two additional re-purposing scenarios, 'capital light' and 'pivot'. However, to simplify the analysis in this paper they those two scenarios were not presented.

TABLE 3.1: MARKET SCENARIOS

Market scenario	Description
A. Fast wind-down scenario	Gas throughput and connections reduce rapidly, with gas consumers transitioning to alternative energy sources (e.g., residential and commercial users switch to electricity, no new connections), incurring relevant conversion costs with pipeline use ceased by 2040
B. Slow wind-down scenario	As per fast wind-down scenario, except gas throughput and connections reduce more gradually with pipeline use cease by 2050
C. Optimistic hydrogen re-purposing	Gas throughput rapidly transitions from natural gas to hydrogen gas or biomethane. By 2050, green gas throughput will be 50% of existing throughput and natural gas throughput will be zero
D. Pessimistic hydrogen re-purposing	As per optimistic hydrogen re-purposing, except that by 2050 green gas throughput is 20% of existing natural gas throughput

Different scenarios were used to assess different analysis questions. For instance, the winddown scenarios (A and B) were used to assess cost recovery risk in question 1, while the two re-purposing scenarios (C and D) were used to assess the potential impact of re-purposing in question 2. For the remaining questions one winddown scenario (A) and one re-purposing scenario (D) were used so as to simplify the analysis.

3.4. Willingness to pay

An important component of the modelling is forecast willingness to pay (WTP), which is a prediction as to how much consumers are willing to pay for delivered gas before they would choose not to consume (e.g., to take up alternative energy sources or otherwise cease using cease).

For each scenario, WTP was projected for each consumer type by combining:

- the projected price of alternative energy sources (such as electricity and biomass)
- the cost of converting from gas to alternative energy, including any make good costs
- an assumed markup (of 10%) to reflect non-price factors, such as consumer stickiness,[9] amenity value, and other desirable characteristics of using gas appliances (e.g., instantaneous hot water).

Of these, the markup for non-price factors is likely to be most uncertain. The points above and anecdotal evidence of gas consumer behaviour suggest that the mark-up is likely to be positive. However, a precise estimate is difficult to determine. A 10% assumption was adopted as a placeholder intended to align with historical observations that for some gas consumers it would appear to make sense, economically, to switch to alternative energy sources. For a residential consumer a 10% margin implies a margin of around $150 per year on current annual gas bills of around $1,500 per year. However, this assumption is not based on any empirical analysis.

9 Consumer stickiness is the phenomenon whereby consumers are tend to be slow to switch from one supplier to another even though it is economically sensible to do so (e.g., switching energy retailers or telecom providers).

Further work could be done to better understand how non-price factors have historically affected demand for gas and what this may mean for gas demand in the future.

This is discussed further in section A.7 of Appendix A.

3.5. Limitations

This analysis is preliminary and conceptual in nature. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes. The analysis has not been undertaken to a specific accounting or other standard.

The working group has not sought to assess the financial performance or position of any specific gas pipeline business, nor quantify the risks that they face. The analysis should not be relied on to inform financial or commercial decisions.

Specific limitations for the analysis undertaken on each of the analysis questions are discussed in each subsection in the next section below. Section A.6 of Appendix A outlines key model assumptions and limitations.

4. INITIAL ANALYSIS

4.1. Overview

The working group has constrained its initial analysis to just five questions:

1. **Cost recovery risk |** *What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?*

2. **Impact of re-purposing |** *How is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners affected by the potential for re-purposing and differences in willingness to pay across customer classes?*

3. **Implications for infrastructure owners |** *What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?*

4. **Implications for consumers |** *What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?*

5. **Policy and regulatory levers |** *How could the implications for gas infrastructure owners and consumers be affected by future policy and regulatory decisions? What impact could different levers have (e.g., regulatory settings, government support)?*

Moreover, this analysis is only a first look at these questions based on a preliminary set of inputs and assumptions and an initial model build. The working group expects to refine and evolve this analysis over time, including to consider other questions that may arise and further input from stakeholders. For this reason, the working group cautions against drawing inappropriate or incomplete conclusions from this analysis at this early stage.

The rest of this chapter steps through initial analysis for each of the five questions, discussing relevant context and predictions, before exploring the outputs from the modelling. Key initial insights are identified throughout.

4.2. Question 1: Cost recovery risk

What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?

Box 3: Cost recovery risk | Summary

- A winddown of regulated gas pipelines exposes gas infrastructure owners to material cost recovery risk – both in terms of unrecovered allowed revenue while the pipeline is operating and unrecovered capital when it ceases operating (i.e., as reflected in the regulated asset base, or RAB, at that time).
- Initial analysis indicates that a winddown of regulated gas pipelines exposes gas infrastructure owners to material cost recovery risk:
    - $948 million if winddown occurs by 2050, and
    - $1,222 million if it occurs by 2040,

  both in present value terms ($2021) and *assuming* no regulatory or policy levers (or mitigations) are applied.
- Notwithstanding modelling limitations, it appears there is no doubt that under both fast and slow winddown scenarios – and under all sensitivities tested – that cost recovery risk will occur with the modelling uncertainties being about the speed with which this risk will crystallise and the magnitude of it.
- Although alternative assumptions (e.g., as to the ability to recover allowed revenue) will affect that risk, current regulatory settings (e.g., depreciation of long-lived assets) – if maintained – will appear to lead to sizable unrecovered capital if pipelines no longer service gas consumers in a winddown scenario.
- In terms of timing, the incidence of unrecovered costs will predominantly occur once gas infrastructure is no longer used (e.g., any unrecovered capital). Unrecovered costs before that time will be a smaller amount.
- This analysis is preliminary and conceptual. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes. Further work is needed to better refine the modelling and inputs.

4.2.1. Context

The current regulatory approach to setting allowed revenues and prices for regulated gas pipelines is to plan and implement expenditures – investment and operating costs – to meet forecast demand efficiently; and then spread the recovery of long-lived capital investments over long periods (e.g., typically at least 50 years) reflecting the expected technical life of the pipeline assets. This approach defers the recovery of much of the investment to future generations of consumers who will benefit from use of the assets over their life.

Planning for meeting demand efficiently and spreading of costs in this way is predicated on the market for gas transportation services remaining at similar levels as today. If that market were to significantly reduce in size or cease entirely due to Government action on climate change, then it is unlikely that investment costs and associated operating costs could be recovered in full because there will be insufficient demand for regulated gas transportation services and related to this, limits on the willingness to pay by consumers higher prices resulting from the reduced demand available to recover past costs.

4.2.2. Focus of analysis

Cost recovery risk will be affected by whether Government action seeks to achieve a winddown of gas pipeline infrastructure or to repurpose it to transport green gases. Question 1 focuses on cost recovery risk in the winddown scenario, and the next section considers the impact that re-purposing may have on cost recovery risk.

Given the long-lived nature of gas pipeline infrastructure, the initial analysis is concerned with how cost recovery risk changes over the medium to long term, both in terms of materiality and trajectory. The Government's target of net zero by 2050 provides a useful starting point for this horizon, and so the analysis focuses on the period from 2021 out to 2055.

To provide a baseline, the initial analysis ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery risk. Section 4.5.1 – which looks at question 5 – considers the impact that potential policy and regulation decisions may have on cost recovery risk.

4.2.3. Prediction

The *premise* is that if Government action is effective in phasing out natural gas (e.g., by banning new connections to gas pipelines and/or mandating or incentivising conversion across to alternative energy sources), then cost recovery risk will increase over time as gas consumers defect from the networks.

The materiality and trajectory through time of that risk will depend on:

- the demand that remains in each future year for gas transportation services
- the value of unrecovered investment costs (represented by the size of the Regulated Asset Base (RAB))
- the level of allowed revenue and the prices that can be feasibly charged (having regard to consumers willing to pay given the alternatives they face); and
- the requirement for future expenditure (e.g., new investment to maintain a safe and reliable gas supply or support growth, and to allow for future decommissioning gas infrastructure).

The profile or trajectory of that risk will depend on the speed with which demand reduces, when future expenditure is needed, and the revenue that regulated gas pipelines are allowed to recover from gas consumers while they remain on the network.

4.2.4. Initial quantitative analysis results

The initial quantitative analysis undertaken by the working group confirms the prediction that a winddown of gas infrastructure will lead to a material risk of cost under recovery.

The key drivers of this risk are:

- declining demand reducing the allowable revenue that can be recovered from gas consumers
- the current regulatory settings (e.g., depreciation profiles) mean that the value of unrecovered capital (i.e., the regulated asset base, or RAB) will be material when the pipelines are fully wound down.

Although affected by whether a fast or slow winddown occurs, the risk remains material under both scenarios.

These drivers are illustrated by the modelling results shown below for:

- recoverable and unrecoverable revenue projections
- cashflow projections
- projected regulatory asset bases

Recoverable and unrecoverable revenue projections

Figure 4.1 compares the recoverable and unrecoverable revenue under both winddown scenarios and across transmission and distribution. It shows that the proportion of allowable revenue (i.e., BBAR) that is unrecovered increases over time. However, consistent with the projected demand profiles, the decline in recoverable revenue occurs over a longer period under the slow winddown scenario.

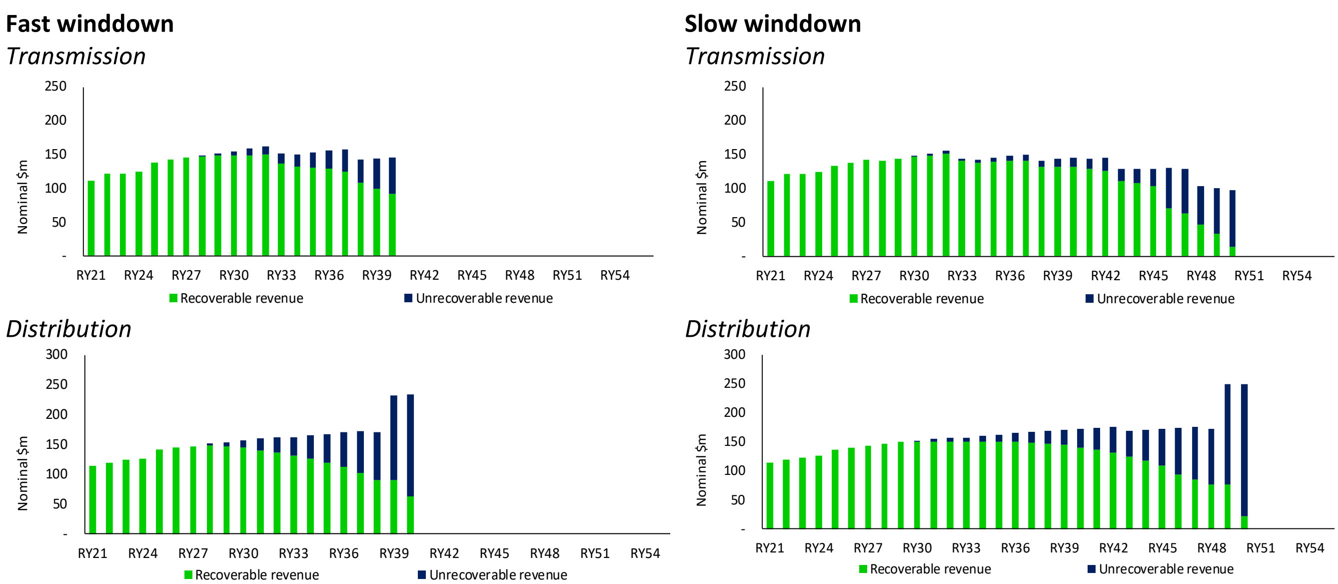
This trend occurs because forecast revenue that is recoverable from gas consumers is projected to decline noticeably faster than allowable revenue. Forecast revenue falls because demand is projected to decline to zero by the time the pipelines are assumed to stop operating (i.e., either 2040 or 2050), while willingness to pay per consumer remains relatively stable. Allowed revenue is projected to decline more slowly largely because the RAB is depreciated over a longer horizon.[10]

As a simplification, the analysis assumes that the share of allowable revenue recovered from different consumer types remains fixed. Similarly, producers are assumed to retain their existing margins rather than absorb some of the unrecoverable revenue.[11]

While a projected increase in unrecoverable revenue is visible for both the transmission and distribution sectors, the proportion of unrecovered revenue is higher for distribution. There tend to be larger step changes in recoverable revenue from year to year for the transmission sector relative to distribution, which reflects assumptions that large direct users will cease use of transmission pipeline services in a stepwise fashion.

As shown in Table 4.1, over the period out to winddown unrecoverable revenue sums to $134 million and $333 million in present value terms (2021 dollars) for transmission and distribution businesses respectively under the fast winddown scenario, and $106 million and $343 million respectively under the slow winddown scenario.

FIGURE 4.1: RECOVERABLE AND UNRECOVERABLE REVENUE



Note: The significant increase in unrecoverable revenues in the final years for the gas distribution businesses are due to forecast decomisisoing costs.

10 The analysis shown in this section does not factor in any potential mitigations, such as accelerated depreciation, which may bring forward allowed revenue.

11 Relaxing these assumptions may reduce projected unrecoverable revenue. For instance, gas pipelines could rebalance tariffs so that consumers that have greater willingness to pay face higher prices. Alternative, they could negotiate with producers to share some of the unrecoverable revenue.

TABLE 4.1: PRESENT VALUE OF RECOVERABLE AND UNRECOVERABLE REVENUE

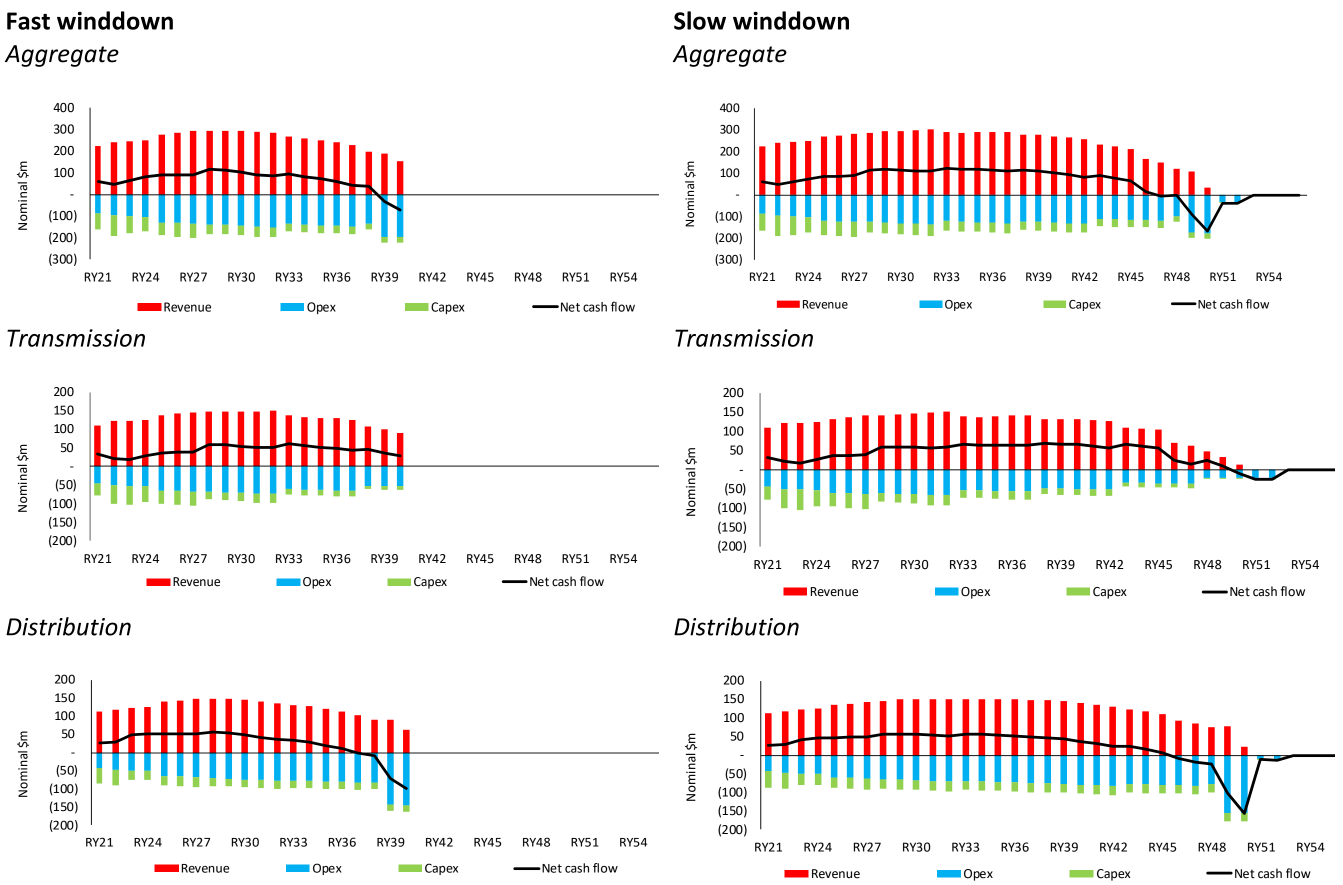
Sector	Scenario	Recoverable Revenue (RY21 $m)	Unrecoverable Revenue (RY21 $m)	Target Revenue (RY21 $m)
Transmission	Fast Winddown	1,786	134	1,920
	Slow Winddown	2,054	160	2,214
Distribution	Fast Winddown	1,675	333	2,007
	Slow Winddown	2,160	343	2,503

Note: Figures may not sum due to rounding

Cashflow projections

Figure 4.2 shows that under-recovery of allowed revenue translates into negative cash flows (before interest and tax) for both transmission and distribution sectors over the modelled horizon, especially in years leading up to when gas demand ceases. As shown in Table 4.2, the present value of net cash flows for transmission and distribution businesses are $558 million and $385 million respectively under the fast winddown scenario, and $741 million and $570 million respectively under the slow winddown scenario.

FIGURE 4.2: NET CASH FLOWS (BEFORE INTEREST AND TAX)



Note: The significant fall in net cash flows in the final years for the gas distribution businesses are due to forecast decomisisoing costs.

Projected regulatory asset bases

Figure 4.3 shows the projected RABs for the transmission and distribution sectors under both winddown scenarios over time under current regulatory settings. Consistent with the demand and expenditure profiles, both transmission and distribution RABs decline over time, especially in the years following winddown (as no new capital investment is undertaken).[12]

However, under base case modelling assumptions, a positive RAB remains after the wind down through to the end of the modelling period. This is the case under both the fast and slow winddown scenarios. As there is assumed to be no demand after winddown, the RAB value at that time is effectively unrecovered – and therefore represents a potential asset stranding risk *if* the corresponding scenario occurs.

As shown in Table 4.2, the estimated present value of the terminal RAB for transmission and distribution businesses are $332 million and $423 million respectively under the fast winddown scenario, and $179 million and $266 million respectively under the slow winddown.

FIGURE 4.3: REGULATORY ASSET BASE

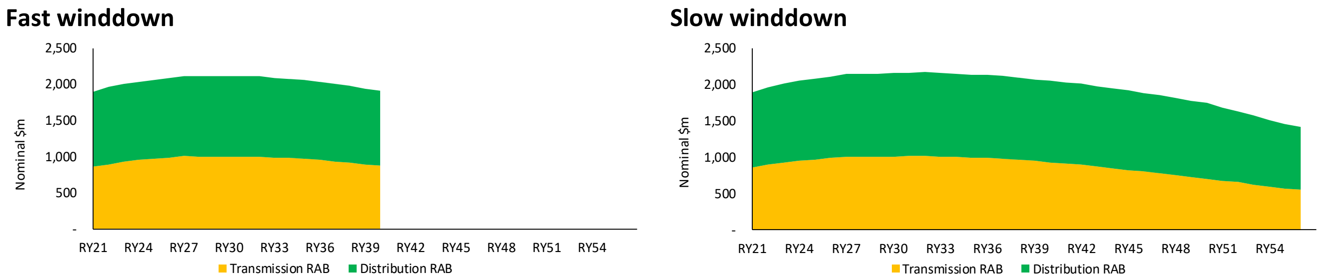


TABLE 4.2: PRESENT VALUE OF CASH FLOWS AND TERMINAL RAB

Sector	Scenario	PV of net cash flows (before interest and tax) (RY21 $m)	PV of Terminal RAB (RY21 $m)	Regulatory Year of Terminal RAB	Total PV (RY21 $m)
Transmission	**Fast Winddown**	558	332	RY40	890
	Slow Winddown	741	179	RY50	920
Distribution	**Fast Winddown**	385	423	RY40	808
	Slow Winddown	570	266	RY50	835

12 Consistent with the regulatory framework applying to GPBs currently, the RABs are subject to CPI revaluation (or indexation) from one year to the next. This has the effect of deferring capital recovery and is why the RABs remain relatively higher over the horizons shown. One regulatory lever considered in section 4.6 is to remove indexation, which will have the effect of bringing forward capital recovery relative to a base case where indexation continues to apply.

Sensitivity analysis

Table 4.3 presents the results of a sensitivity analysis, using the fast winddown scenario as an example. Sensitivity analysis of the fast winddown scenario shows that:

- Increasing the **regulated WACC** by 1% has a strong positive impact on cash flow, reflecting a higher return on capital and BBAR in the years before the willingness to pay cap starts to apply. The impact on cash flow is especially significant for the distribution sector. This is partly because allowable revenue drops away more strongly for the distribution sector relative to the transmission sector. Therefore, net cash flow over the initial years – where the WACC sensitivity has the most impact – makes up a larger proportion of total cash flows for the distribution sector.
- Shortening **asset lives** by 50% also has a strong positive impact on cash flow for both the transmission and distribution sectors. However, the increase in BBAR due to a higher depreciation allowance partly offsets the fall in BBAR due to a lower RAB and therefore lower return on capital. The terminal RAB is lower.
- Increasing the **assumed willingness to pay** has a relatively strong positive impact on cash flow for the distribution sector and a more moderate impact for the transmission sector. This is in part due to the different customer mix. For residential and commercial consumers in the distribution sector, the willingness to pay cap tends to be more binding than other consumer groups. This results in a higher proportion of unrecoverable revenue in the base case for the distribution sector relative to the transmission sector, which can be reduced by the adjustment in willingness to pay.
- Increasing connections and **demand** by 20% means that costs can be spread over a larger number of consumers, leading to higher recoverable revenue. As there is no impact on costs, net cash flow rises. The impact is strongest for the distribution sector relative to the transmission sector, due to the relatively higher number of individual connections.

TABLE 4.3: PRESENT VALUE OF CASH FLOWS AND TERMINAL RAB BY SENSITIVITY – FAST WINDDOWN

Sensitivity	Sector	PV of net cash flows (before interest and tax) (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
Base case	Transmission	558	332	890
	Distribution	385	423	808
	Total	943	754	1,698
WACC +1%	Transmission	709	332	1,041
	Distribution	510	423	933
	Total	1,219	754	1,974
Shorter asset lives by 50%	Transmission	675	251	926
	Distribution	487	332	819
	Total	1,163	582	1,745
Willingness to pay +10%	Transmission	581	332	913

Sensitivity	Sector	PV of net cash flows (before interest and tax) (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
	Distribution	435	423	858
	Total	1,016	754	1,770
Demand + 20%	**Transmission**	583	332	915
	Distribution	441	423	864
	Total	1,025	754	1,779

Limitations

This analysis is subject to the limitations noted in section 3.5.

However, notwithstanding these limitations, it appears that under all scenarios and sensitivities considered that cost under recovery will occur. Modeling uncertainties being about the speed and timing for when this risk will crystallize and the magnitude of it.

Willingness to pay assumptions are particularly important to the analysis because they affect the amount of allowed revenue that regulated gas pipelines are projected to recover. Further work to better understand willingness to pay is recommended, including to better assess non-price factors that influence gas consumers decisions to use gas or alternative energy sources. Another related question is to explore supply chain impacts, such as the possibility of cost pressures leading to lower margins for gas producers and retailers.

As noted above this conceptual analysis considers only private costs and benefits. Consideration could be given to whether there are further is whether are material external costs and benefits that would warrant undertaking a broader social cost-benefit analysis.

4.2.5. Key insights

The initial analysis above suggests that a winddown of regulated gas pipelines exposes gas infrastructure owners to material cost recovery risk.

The pace of winddown will affect that risk – however it appears to remain material under the two scenarios considered in this paper. And although alternative assumptions (e.g., as to the ability to recover allowed revenue) will affect that risk, current regulatory settings (e.g., depreciation of long-lived assets) – if maintained – will appear to lead to sizable unrecovered capital once the pipelines no longer service gas consumers.

Absent mitigation, such projections suggest that the gas pipelines will not remain financially viable under a winddown scenario. Faced with that outlook it may be rational for gas infrastructure owners to shutdown uneconomic sections of their infrastructure sooner than is socially desirable.

Importantly, the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on the results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This model logic can be adjusted and is being reviewed.

Further work could be undertaken to better understand cost recovery risk under a winddown scenario, including as to what revenue gas infrastructure owners may be able to realise from gas consumers and what mitigations could be taken (e.g., changes to regulatory settings or offset the risk faced). The model logic for allocating revenue received from end gas consumers across the supply chain could also revised.

4.3. Question 2: Impact of re-purposing

How is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners affected by the potential for re-purposing and differences in willingness to pay across customer classes?

Box 4: Impact of re-purposing | Summary

- The initial analysis suggests that re-purposing gas infrastructure could reduce cost recovery risk. This occurs not only because net cash flows may improve relative to a winddown scenario, but also because the infrastructure will continue as a going concern and so there remains potential to recover unrecovered capital costs – as measured by the projected value of the RAB – after the point where the infrastructure would otherwise have ceased operating.
- The extent of any re-purposing – and therefore any reduction in cost recovery risk – will depend on the potential revenue that could be recovered from gas demand that remains relative to the costs of re-purposing. If incremental costs from repurposing can be recovered from incremental revenue over an appropriate timeframe, then it may be sensible to pursue re-purposing.
- Further analysis will be needed to better understand this dynamic, including as to the difference in cost between green gas and alternative energy sources and what this means for willingness to pay (although uncertainty is still likely to remain even after further analysis). The optimistic and pessimistic scenarios modelled are based on assumptions including the potential for hydrogen to become competitive with electricity and other alternative energy sources, about which there is debate – these assumptions affect the conclusions that can be made.
- As noted in section 2.7 there are differing perspectives on the economic viability of re-purposing scenarios, although most recognise that the prospects of re-purposing will be driven by the cost of fuel. The optimistic and pessimistic scenarios modelled by the working group assume that the cost of hydrogen production under the re-purposing scenarios is economically viable.[13]

4.3.1. Context

Section 4.2 – which looked at question 1 – explored the extent and trajectory of cost recovery risk under a winddown scenario where Government action on climate change leads to a decline in demand for gas pipeline services.

As noted in section 2.3 and 4.2.5, that analysis considers only private costs and benefits to gas pipeline owners and consumers in a re-purposing scenario. The analysis uses differences in cost recovery risk – between winddown and re-purposing scenario – as a measure of net benefit from re-purposing to pipeline owners. This cost recovery risk will be affected by whether some or all gas pipeline infrastructure can continue to be used and useful once nature gas is phased

13 Further work will be needed to better understand the prospects for re-purposing in New Zealand and the key factors that affect those prospects.

out, most likely by re-purposing it to transport green gases. In that case, prices paid by consumers that continue to use and pay for gas pipeline services may allow gas infrastructure owners to recover at least some of their efficient costs of providing gas distribution and transmission services as well as to avoid decommissioning costs.

Question 2 explores how cost recovery risk is affected by the potential for re-purposing – a scenario that could evolve organically or be actively supported by Government and Commerce Commission action. The analysis assumes that if re-purposing goes ahead, it is economic for both the gas infrastructure owners and gas consumers to continue providing and procuring gas pipeline services.

4.3.2. Focus of analysis

This analysis focuses on the projected outcomes under the re-purposing scenarios. It considers the same horizon that in section 4.2 because it is concerned with how re-purposing could affect cost recovery over the medium to long term as natural gas is phased out and green gas is phased in. The analysis does not consider the likelihood of re-purposing occurring in practice.

Like in section 4.2 – and except for actions to support re-purposing – this analysis ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery risk.

4.3.3. Prediction

The *premise* is that re-purposing will reduce cost recovery risk if it goes ahead.[14] This would occur where at least some of the existing unrecovered capital can be recovered from consumers that continue to use gas pipeline services.

If, however, the incremental revenue from re-purposing does not recover the incremental costs (e.g., of converting pipeline infrastructure) and avoidance of decommissioning and disconnection costs, then such re-purposing may increase cost recovery risk rather than reduce it.

The extent of any reduction in cost recovery risk will depend on:

- the demand that remains for gas transportation services – which will be influenced by the relative costs of transporting energy as a gas rather than in other forms, such as solid biomass, electricity
- the willingness of gas consumers to pay the costs of re-purposing, which will be affected by the wholesale cost of green gas compared with alternatives such as electricity and differences across customer types
- the level of re-purposing costs
- the value of unrecovered investment costs (e.g., the size of the existing RAB)
- the level of allowed revenue / prices
- the requirement for future expenditure (e.g., new investment to maintain a safe and reliable gas supply or support growth, and to decommissioning gas infrastructure).

The profile or trajectory of such reduction will depend on how demand, expenditure, and allowed revenue change under a re-purposing scenario compared with a winddown scenario.

4.3.4. Initial quantitative analysis results

The initial quantitative analysis undertaken by the working group suggests that re-purposing gas infrastructure to transport green gas could reduce cost recovery risk.

The analysis also suggests that this is more likely under a pessimistic rather than an optimistic re-purposing scenario. This is because only some of the infrastructure comprising the more economic parts of the network is re-purposed, which reduces the cost of operating and maintaining the infrastructure.

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14 This will require a level of coordination between consumers and supplier(s) controlling each element of the supply chain.

The key drivers of this result is that retaining some gas consumption and transportation services in the long term allows for a larger share of allowed gas pipeline revenue to be recovered and avoids some or all decommissioning and disconnection costs that would otherwise be incurred if the infrastructure was wound down.

The impact of re-purposing is best understood by comparing the net cash flows between the re-purposing scenarios and the slow winddown scenario. Other ways of assessing the impact are:

- projecting the value of the regulatory asset base
- projecting gas consumption.

Comparing the net cash flows between the re-purposing scenarios and the slow winddown scenario

Figure 4.4 shows the *change* to cash flows under the optimistic and pessimistic re-purposes scenarios compared with the slow winddown scenario – which is a useful way of understanding what has changed. Bars above zero (e.g., the red revenue bars) indicate cash flows have improved. Bars below zero (e.g., the green capex bars) indicate cash flows that have worsened. When the black line is below zero it means that *net* cash flows are lower than under the winddown, while when it is above zero it means that net cash flows are higher.

As shown in Figure 4.4, net cash flows are lower under an optimistic re-purposing scenario for the period up to 2045 due to investment needed during that period to repurpose the infrastructure (i.e., the green bars below the horizontal axis). From 2045 to the early 2050s cash flows are noticeably more positive as gas consumption and transportation services continue, leading to higher revenues (i.e., the reg bards above the horizontal axis).

In contrast, under the pessimistic re-purposing scenario cash flows do not materially decline (relative to a slow winddown) as less investment is needed to repurpose the infrastructure. However, gas infrastructure nevertheless experiences a noticeable increase from around 2045 – which suggests the under that scenario gas infrastructure can benefit from some gas demand remaining at a lower capital (re-purposing) cost than under the optimistic re-purposing scenario.

FIGURE 4.4: NET CASH FLOWS (BEFORE INTEREST AND TAX): CHANGE RELATIVE TO A SLOW WINDDOWN (SCENARIO B)

Optimistic re-purposing
Transmission + distribution combined

Pessimistic re-purposing
Transmission + distribution combined

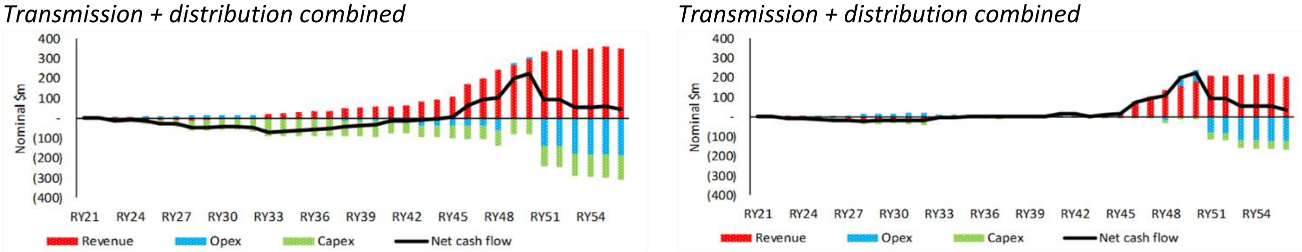


TABLE 4.4: PRESENT VALUE OF CASH FLOWS (COMPARISON TO SLOW-WINDDOWN)

Sector	Scenario	PV of net cash flows (before interest and tax) (RY21 $m)	Comparison to Slow-Winddown
Transmission	**Optimistic re-purposing**	641	(100)
	Pessimistic re-purposing	839	98
Distribution	**Optimistic re-purposing**	751	181

	Pessimistic re-purposing	861	291

Projecting the value of the regulatory asset base

The RAB is a measure of the capital investment that has not yet been recovered through regulated revenues that gas pipeline businesses are allowed to recover:

- under a winddown scenario – where pipeline infrastructure is assumed to cease operating – a positive RAB value at the point when operations cease indicates the value of stranded assets as no further revenue is expected to be recoverable (i.e., 100% probability of no recovery of capital or other costs from that point forward)
- under a re-purposing scenario a positive RAB *may* still be recoverable as the infrastructure continues as a going concern and gas consumers continue to pay for pipeline services.

As shown in Figure 4.5, the projected regulatory asset base (RAB) under the optimistic re-purposing scenario – where a significant amount of new investment is needed – continues to grow over the forecast horizon. This assumes that the *current* regulatory settings apply (e.g., no change to how depreciation is calculated).

In contrast under the pessimistic re-purposing scenario the RAB is projected to peak around 2032 and then decline after that due to a lower level of new investment required.

In both scenarios the gas infrastructure entities will continue to be going concerns into the future – which means that there remains opportunity to recover any unrecovered capital (i.e., the RAB) beyond the horizon projected in Figure 4.5.

FIGURE 4.5: REGULATORY ASSET BASE

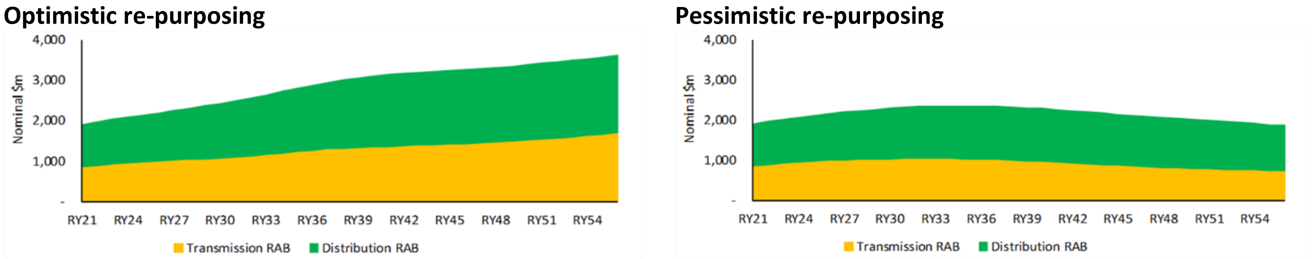


TABLE 4.5: PRESENT VALUE OF CASH FLOWS AND TERMINAL RAB

Sector	Scenario	PV of net cash flows (before interest and tax) (RY21 $m)	PV of Terminal RAB (RY21 $m)	Total PV (RY21 $m)
Transmission	**Optimistic re-purposing**	641	327	968
	Pessimistic re-purposing	839	145	983
Distribution	**Optimistic re-purposing**	751	367	1,119
	Pessimistic re-purposing	861	216	1,077

Projecting Gas Consumption

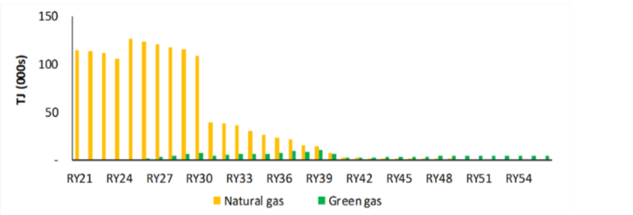
Figure 4.6 shows how under a repurpose scenario green gas is projected to replace natural gas over time, with a lower level of green gas under pessimistic re-purposing compared with optimistic re-purposing. Given that some gas demand remains, there is scope to recover at least some of the RAB projected over the modelling horizon.

It also shows that most green gas is assumed to be injected directly into distribution businesses (shown by the larger green bars for distribution than transmission). However other potential futures exist – such as the bulk import of hydrogen to Taranaki and transmission from there – would materially change this picture.

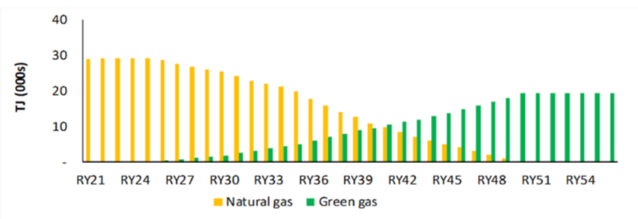
FIGURE 4.6: CONSUMPTION OF GAS

Optimistic re-purposing

Transmission

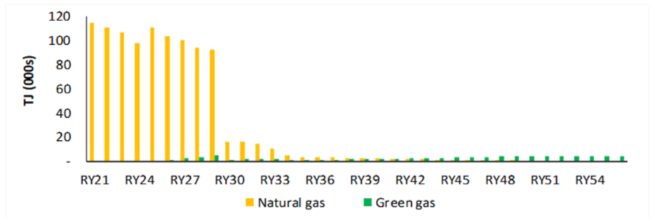


Distribution

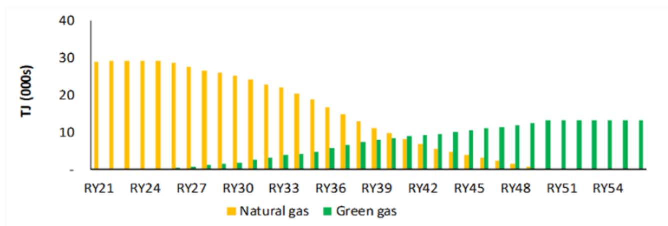


Pessimistic re-purposing

Transmission



Distribution



Sensitivity analysis

Sensitivity analysis of the optimistic re-purposing scenario suggest that the financial viability impacts of re-purposing is affected by assumptions on willingness to pay, demand, and expenditure.

Table 4.6 presents the results of a sensitivity analysis, using the optimistic repurposing scenario as an example. The analysis shows that:

- Increasing the **assumed willingness to pay** has a strong positive impact on cash flow – a higher willingness to pay has the effect of increasing recoverable revenue as consumers are less willing to switch to alternative energy. This is a similar result to the one found under the winddown scenarios (section 4.2 above) where the level of alternative energy prices relative to gas means that only part of the BBAR is recovered in most years under the base case. As under the winddown scenarios, the impact tends to be larger in the distribution sector relative to the transmission sector.
- Increasing **demand** and connections by 20% also leads to an increase in net cash flow – as costs can be spread over a larger number of consumers, recoverable revenue rises and there is no corresponding rise in costs. A similar result is observed under the fast winddown scenarios (section 4.2 above) and again the impact is larger for the distribution sector than the transmission sector.
- Increasing **capex and opex** by 10% has a relatively strong negative impact on cash flow. This occurs for both the transmission and distribution sectors, illustrating the potential impact on cash flow of expenditures that differ from expected values, even in a regulated environment.

TABLE 4.6: PRESENT VALUE OF CASH FLOWS AND TERMINAL RAB BY SENSITIVITY – OPTIMISTIC REPURPOSING

Sensitivity	Sector	PV of net cash flows (before interest and tax) (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
Base case	**Transmission**	641	327	968
	Distribution	751	367	1,119
	Total	1,392	694	2,086
Willingness to pay +10%	**Transmission**	694	327	1,020
	Distribution	800	367	1,168
	Total	1,494	694	2,188
Demand + 20%	**Transmission**	681	327	1,008
	Distribution	792	367	1,159
	Total	1,473	694	2167
Capex and opex +10%	**Transmission**	580	357	937
	Distribution	699	398	1,096
	Total	1,278	755	2034

Limitations

This conceptual analysis is subject to the limitations noted in section 3.4

Significant care should be taken before reading too much into the initial results above. There is significant uncertainty over demand assumptions over the horizon used and what revenue will be recoverable under a re-purposing scenario. The initial assumptions and projections used will need significant testing before reliable conclusions can be drawn.

Moreover, although care has been taken to prepare the modelling and inputs to it, the conceptual analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes. Further work is needed to better refine the modelling and inputs.

Willingness to pay assumptions are particularly important to the analysis because they affect what demand may remain if the gas infrastructure is repurposed and the amount of allowed revenue that regulated gas pipelines are projected to recover. Further work to understand willingness to pay would be sensible, including to better assess non-price factors that influence gas consumers decisions to use gas or alternative energy sources and to understand cost differences between green gas and those alternative sources.

As noted above this conceptual analysis considers only private costs and benefits. Consideration could be given to whether there are material external costs and benefits that would warrant consideration in a broader social cost-benefit analysis.

4.3.5. Key insights

The initial analysis above suggests that re-purposing gas infrastructure *could* reduce cost recovery risk by improving net cash flows while operating compared with the winddown scenarios and – by remaining a going concern – providing an opportunity to recover any unrecovered capital (as reflected in the RAB).

The extent of re-purposing – and the costs of that – relative to revenue that can be recovered from gas demand that remains will be the key to any reduction. If incremental costs from re-purposing can be recovered from incremental revenue, then it may be sensible to pursue re-purposing.

Further analysis will be needed to better understand this dynamic, including as to the difference in cost between green gas and alternative energy sources and what this means for willingness to pay. The optimistic and pessimistic scenarios modelled by the working group are based on assumptions reflect differing perspectives on the future likelihood of hydrogen becoming competitive with electricity in enough range of end uses to support transportation by way of gas pipelines. The view taken on these perspectives affects the conclusions that can be made. An important caveat for policy and regulatory decisions at the present time.

4.4. Question 3: Implications for gas infrastructure owners

What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?

Box 5: Implications for gas infrastructure owners | Summary

- Initial analysis suggests that the financial viability of GPBs is at risk under all modelled scenarios, *assuming* no change to current regulatory settings or Government intervention. This is consistent with the insight in sections 4.2 and 4.3 above.
- Key drivers of the size of this risk are gas consumers' future demand and willingness to pay for gas transportation services, which largely drives GPB's net cash flows.
- Declining cash flows under both scenarios reduces the creditworthiness of GPBs and projected returns on investment (ROIs).
- Cash flow and ROI projections suggest that changes will need to be made to regulatory and policy settings for gas pipelines to remain financially viable under a winddown scenario.
- Faced with that outlook it may be rational for gas infrastructure owners to shutdown uneconomic sections of their infrastructure sooner than is socially desirable. If shutdown did occur, then energy consumers would lose the option to choose reticulated gas as an energy source.
- Alternatively, it may also be rationale for gas infrastructure owners to actively pursue re-purposing as a way of mitigating the risk of under-recovery under a winddown scenario. Such incentives, however, are undermined by uncertainty over the future viability of green gases.
- Any investment to preserve the option of future green gases will need to balance the risk that that investment will not be recovered – e.g., because re-purposing does not occur – with the potential reduction in cost recovery risk from undertaking it.

- Further work could be undertaken to better understand the drivers of the cash flow projections under both winddown and repurposing scenarios, including as to what revenue gas infrastructure owners may be able to realise from gas consumers and what mitigations could be taken (e.g., changes to regulatory settings go offset the risk faced). Modelling how future investment decision may occur could also provide useful insight.

4.4.1. Context

Cost recovery risk is related to the financial viability of infrastructure owners. This is because the financial obligations (debt and other liabilities) of those owners can be expected to have been entered into assuming that they could recover their efficient costs, including past investment in pipeline infrastructure. Higher cost recovery risk implies worsening financial viability because it suggests that future cash flows to infrastructure owners are riskier (and vice versa).

Sections 4.2 and 4.3 – which considered questions 1 and 2 – had an initial look at the potential extent (and trajectory) of cost recovery risk under the winddown and re-purposing scenarios. Question 3 considers the implications of this cost recovery risk for the financial viability of gas infrastructure owners.

4.4.2. Focus of analysis

The analysis focuses on the projected implications to gas infrastructure owners under the various market scenarios being considered. It considers the same horizon as that in sections 4.2 and 4.3 and ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery risk or the implications to gas infrastructure owners.

As well as looking at projected cash flows and ROI, the working group also considered two measures of credit worthiness:

- operating cash flow to debt ratio – which measures the ratio of operating cash flow to debt and signals how much cash a business has available to service debt
- leverage ratio – which measures the ratio of debt to total asset value and signals how much of a business' value is funded by debt (as opposed to equity).[15]

A *higher* operating cash flow to debt ratio and *lower* leverage ratio suggests *improved* credit worthiness, and vice versa. Although these two measures or credit metrics are not presented below, they are consistent with the net cash flow and ROI charts that are.

4.4.3. Prediction

The *premise* is that higher cost recovery risk correlates with worsening financial viability. If re-purposing occurs – and is economic to both gas infrastructure owners and gas consumers – then this should improve financial viability relative to a winddown scenario because it implies that gas pipelines will continue to generate cash inflows that can cover financial obligations.

Financial viability of gas infrastructure owners will depend on:

- projected cash flows – which will be affected by how future revenues and costs compare,[16] and
- current debt and future debt raising needs (e.g., to support future expenditure).

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15 The leverage ratio has been modelled by starting with the leverage ratio reflected in the current WACC allowed by the Commerce Commission and then rolled forward to reflect changes in cash flows and investing activities.

16 A company's ability to create value for shareholders – and therefore to have incentive to invest and stay in business – is fundamentally determined by its ability generate long-term positive free cash flow. A company may choose to stay in business through a period of negative cash flows, but only if it has expectations that net cash flows will turn positive.

Longer term cash flows may be more relevant to assessing financial viability than short term fluctuations (e.g., driven by large expenditure outlays).

4.4.4. Initial quantitative analysis results

Initial analysis

The initial quantitative analysis suggests that a fast winddown of gas infrastructure will reduce the financial viability of the GPBs. The case is a little more mixed if there is optimistic re-purposing of that infrastructure, but with the projected ROI reducing under both scenarios.

The key drivers of this are:

- cash flows being put under pressure due to projected cost under recovery under both scenarios as demand reduces, and
- meaningful levels of expenditures needing to continue even under a fast winddown.

These drivers and their consequences for financial viability and projected returns can be illustrated by considering:

- net cash flows
- return on investment, and
- financeablility (i.e., the ability of GDPs to finance their operations).

Net cash flows

Net cash flows are an important measure of business viability. Although businesses can operate with negative cash flows in some instances (e.g., large capital outlays), longer term this is simply not sustainable as it means that insufficient cash is coming in to pay outgoings. As such, understanding whether and if so for how long a business is expected to face negative or declining cash flows provides insights into whether it is financially viable.

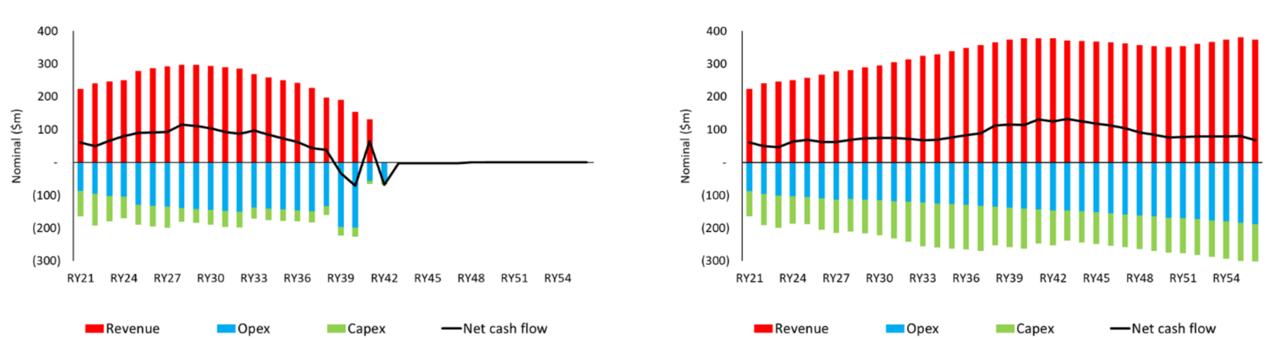
Figure 4.7 compares the net cash flows in aggregate across gas distribution and transmission businesses for both the fast winddown and optimistic re-purposing. It shows that, under the fast winddown scenario, net cash flow tends to remain positive for the initial years. Cash flow then gradually trends downward before dropping strongly and becomes negative in the years leading up to full winddown as decommissioning costs are incurred.

Under the optimistic re-purposing scenario, net cash flows are remain positive and less volatile over the modelling period relative to the fast winddown scenario. However, cash flows show a drop towards the end of the period. This suggests that those businesses may not be financeable viable under the scenarios modelled.

FIGURE 4.7: NET CASH FLOWS (BEFORE INTEREST AND TAX)

Fast winddown | **Optimistic re-purposing**

Transmission + distribution combined | *Transmission + distribution combined*



Return on Investment

The cash flow trajectories affect the estimated ROI of the GPBs. For simplicity, Figure 4.8 compares the projected ROI for the gas distribution and transmission pipelines in aggregate against the assumed regulated WACC under both the fast winddown and optimistic re-purposing scenarios.

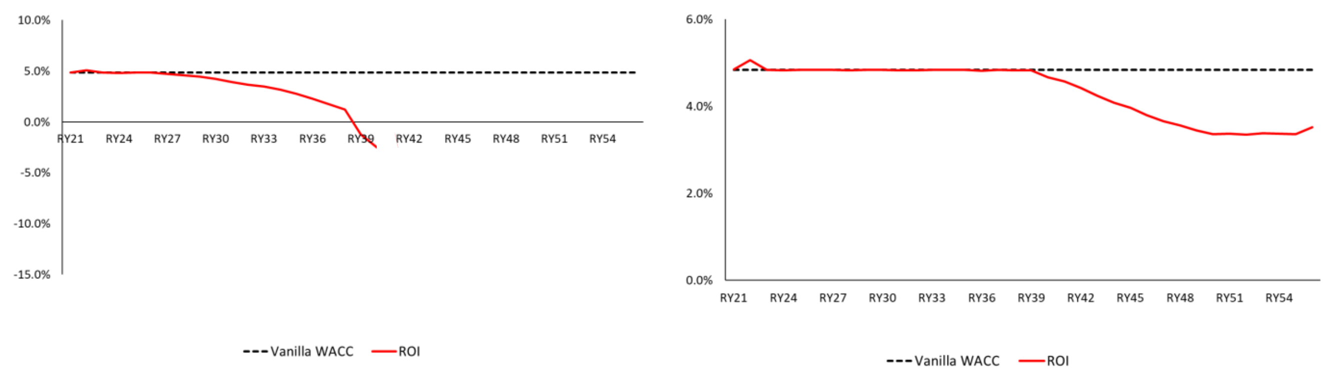
Assuming that the model assumptions are valid it shows that under both the fast winddown and the optimistic re-purposing the ROI for declines gradually over time in proportion to the revenue being recovered and – critically – fall below the cost of capital. If this persists, then it suggests that the financial viability of the GPBs is at risk under either scenario. (Although not presented, similar projections apply under the slow winddown and pessimistic re-purposing scenarios).

Moreover, under the fast winddown the ROI falls significantly below the regulated WACC, eventually falling below zero in line with the reduction in net cash flows. Although the ROI falls below the regulated WACC under the optimistic re-purposing scenario, it does improve slightly later in the modelled horizon.

FIGURE 4.8: RETURN ON INVESTMENT

Fast winddown *Transmission + distribution combined*

Optimistic re-purposing *Transmission + distribution combined*



Note: the scale on the two charts are different. The ROI lines represent the average ROI across the 4 gas distribution networks and 1 gas transmission network, weighted by their respective RAB values.

Financeablility

The cash flow trajectories outlined above would – if realised – materially adversely affect the ability of GPBs to raise capital to continue investing in and operating gas infrastructure (i.e., financeability). Analysis has been undertaken of two measures of financeability – leverage ratios and operating cash to debt across the GPBs – for the different market scenarios that supports this. For simplicity these results are not presented here.

Sensitivity analysis

Sensitivity analysis of both the fast winddown and optimistic re-purposing scenario analysis shows that:

- Increasing the **assumed willingness to pay** has a relatively strong positive impact on cash flow – a higher willingness to pay has the effect of increasing recoverable revenue as consumers are less willing to switch to alternative energy, which is a result that holds under both the fast winddown and the optimistic re-purposing scenarios. However, the impact of changes in willingness to pay are most pronounced:
  - for businesses with a higher exposure to residential versus commercial/industrial consumers because the difference between the gas charge and the alternative energy charge tends to be smaller
  - when there is a higher proportion of unrecoverable revenue (e.g., for the fast winddown scenario relative to the optimistic repurposing scenario)

- Increasing **demand** leads to higher net cash flow across all GPBs – as costs can be spread over a larger number of consumers, recoverable revenue rises and there is no corresponding rise in costs.
- Increasing **capex and opex** by 10% negatively impacts cash flow – this demonstrates the potential impact on cash flow of expenditures that differ from expected values, even in a regulated environment, including because the terminal RAB is higher with an increase in capex. Because capex and opex profiles show substantial variation across businesses, the impacts of this sensitivity also differ between businesses. These differences occur due to both variation in the opex and capex associated with a given scenario as well as the timing of when expenditures are assumed to occur.

Limitations

This conceptual analysis is subject to the limitations noted in section 4.1.3.

Importantly, the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on the results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This model logic can be adjusted and is being reviewed.

Willingness to pay assumptions are particularly important to the analysis because they affect the amount of allowed revenue that regulated gas pipelines are projected to recover. Further work to understand willingness to pay would be sensible, including to better assess non-price factors that influence gas consumers decisions to use gas or alternative energy sources.

4.4.5. Key insights

The initial analysis suggests that the financial viability of GPBs is at risk under either a fast winddown or optimistic re-purposing scenario (assuming no change to current regulatory settings or Government intervention).

Key factors that affects the size of this risk is gas consumers' future demand and willingness to pay for gas transportation services – which largely drives GPB's net cash flows. Declining cash flows under both scenarios reduces the creditworthiness of GPBs and the projected ROIs.

Absent mitigation, such projections suggest that the gas pipelines will not remain financially viable under a winddown scenario. Faced with that outlook it may be rational for GPBs to shutdown uneconomic sections of their infrastructure sooner than is socially desirable.

Further work could be undertaken to better understand the drivers of the cash flow projections under both winddown and re-purposing scenarios, including as to what revenue gas infrastructure owners may be able to realise from gas consumers and what mitigations could be taken (e.g., changes to regulatory settings or offset the risk faced).

4.5. Question 4: Implications for gas consumers

What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?

Box 6: Implications for gas consumers | Summary

- A winddown of gas pipelines exposes the remaining gas consumers to meaningful price increases as other consumers defect up until the infrastructure is shutdown. After that point, consumers lose the choice to consume reticulated gas to meet their energy needs.
- The pace of the winddown will clearly affect that risk – with a faster winddown leading to a faster price increases that will encourage more rapid defection of consumers through the winddown.
- Re-purposing gas infrastructure may help reduce that risk, although further work is needed to better understand what demand may look like under such a scenario.

4.5.1. Context

Gas consumers will be affected by the costs of the energy they consume, the appliances they acquire and replace through time, and any conversion from one energy source to another – ultimately affecting energy affordability (before considering any potential government support).

Energy costs include wholesale costs of gas or alternative energy sources, energy transportation costs, and retail costs. Appliance costs will generally be incurred when they are up for replacement. However, where a consumer switches from one energy source (e.g., natural gas) to another (e.g., hydrogen or electricity) for energy, then it may incur conversion costs (e.g., acquiring and installing new appliances, making good).

The level and profile of costs incurred by gas consumers will depend on whether gas infrastructure is wound down or re-purposed. It will also be affected by the revenues that regulated gas pipelines are allowed to recovery under either scenario.

Question 4 looks at these implications for gas consumers. Conversion costs are factored into gas consumers' assumed willingness to pay.

4.5.2. Focus of analysis

This analysis focuses on the projected implications to gas consumers under the various market scenarios being considered. It considers the same horizon as the analysis in the previous sections and ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery risk or the implications to gas infrastructure owners and gas consumers.

Although the analysis considers many of the costs faced by gas consumers, it is not exhaustive. As noted in section 3.4, the costs of converting from gas to alternative energy sources, including any make good or appliance switching costs, are reflected in projected willingness to pay. In reality, these costs will vary significantly across consumers. Further work could be undertaken to better understand how these costs may differ and how they may influence gas consumer consumption decisions.

4.5.3. Prediction

The *first premise* is that – somewhat obviously – consumers will be affected by and adjust their behaviour in response to changes in the price of gas compared with alternatives.

- Under a **winddown scenario**, those consumers will increasingly face the costs of alternative energy sources such as electricity as natural gas is phased out – and so their energy demand decisions will be affected by cost differences between natural gas and electricity (or other alternatives).

- Under a **re-purposing scenario**, consumers that continue to use gas will be affected by differences between green gas and natural gas prices – and may adjust their behaviour in response to price differences between green gas and alternatives.

The quantitative analysis described below does not model consumer behaviour directly (given the significant challenges in undertaking such modeling). The demand projection assumptions used in the analysis do reflect assumed consumer behavior decisions in response to changes in relative energy costs.

Consumer price impacts (and consumption decisions) will depend on:

- projected distribution and transmission network revenues
- projected natural gas, green gas, and alternative energy source costs (or prices), and
- non-price factors, which are captured in willingness to pay measures and are likely to be more important for residential consumers than other types of consumers.

The *second premise* is that consumers will incur significant costs converting from gas to an alternative energy source if gas infrastructure is wound down or consumers defect as it is economic to do so and that these costs will vary across consumer types.

In some cases, there may be no viable non-gas energy alternatives for some consumer types (e.g., industrial consumers with specific processing requirements) that currently consume natural gas. If they can no longer use gas in New Zealand, then those consumers may need to either cease operations or shift operations to overseas jurisdictions.

4.5.4. Initial quantitative analysis results

The initial quantitative analysis suggests that a fast winddown of gas infrastructure will lead to an accelerating increase in the cost of delivered natural gas for most gas consumers as allowed pipeline revenues are spread over a declining consumer base, *assuming* that:

- all revenues are passed through to consumers
- regulatory settings remain as they do now (i.e., there is no re-profiling of allowed revenue over the forecast horizon), and
- there is no rebalancing of revenue across consumer types.

In reality, such an increase will likely encourage consumers to defect faster (i.e., a death spiral) as alternative energy sources increasingly become more attractive. Similarly, it will encourage networks and regulators to rebalance prices and adjust regulatory settings to mitigate this. Section 4.6 will look at some of those mitigations.

The analysis also suggests that an optimistic re-purposing of the gas infrastructure will likely keep annual consumer charges lower as more consumers are assumed (as an input) to be consuming green gasses. *If* this assumption were relaxed, then it may be that more gas consumers defect than is currently reflected in the modelling. Further work could be done to look at this. But for now it is assumed away.

These dynamics are best shown by considering annual natural gas charges per user.

Annual natural gas charges per user

Figure 4.9. shows that annual natural gas charges – on a per user basis – increase strongly under the fast winddown scenario for residential and commercial distribution customers. This largely reflects fixed costs being borne by a more rapidly decreasing number of connected customers.

In contrast, alternative energy charges remain much more stable under the fast winddown scenario, falling below natural gas charges for a substantial part of the period for residential and commercial distribution customers.

Under the optimistic re-purposing scenario, natural gas charges increase at a slower rate relative to the fast winddown scenario for residential and commercial distribution customers. This means that natural gas charges (in red) fall below alternative energy charges (in blue) for a longer period. As discussed in section 3.4, in practice, gas consumers are assumed to switch to alternative energy sources once projected prices exceed their willingness to pay.

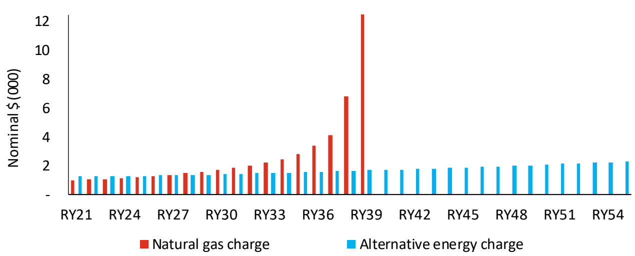
As well as the alternative energy cost, willingness to pay incorporates conversion costs as well as non-price factors through an assumed 10% mark-up. As such, annual willingness to pay sits somewhat above the annual alternative energy costs shown in FIGURE 4.9.

Interestingly, for industrial distribution customers, alternative energy charges increase gradually over time and are significantly higher than natural gas charges in most years under both scenarios. For transmission direct connect customers, alternative energy charges are also well above gas charges. There is greater volatility in alternative energy charges for these customers, as the user profile changes over time. An important limitation, however, is that the initial analysis has not sought to rebalance charges from one customer group to another. Doing so will affect the charges faced by those groups and their comparison to alternative energy charges.

FIGURE 4.9: ANNUAL CHARGES PER CONSUMER BY TYPE

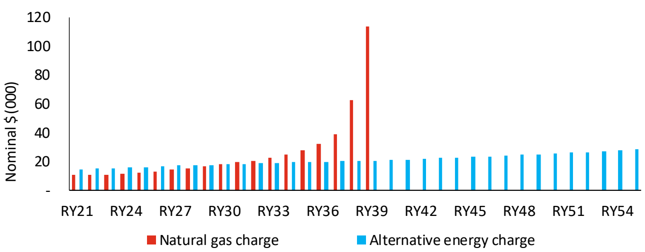
Fast winddown

Residential



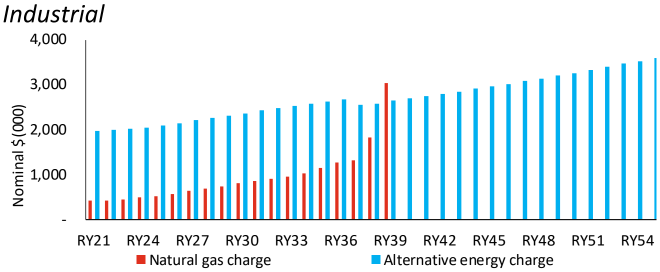
**Natural gas charge > alternative energy charge in RY28*

Commercial



**Natural gas charge > alternative energy charge in RY31*

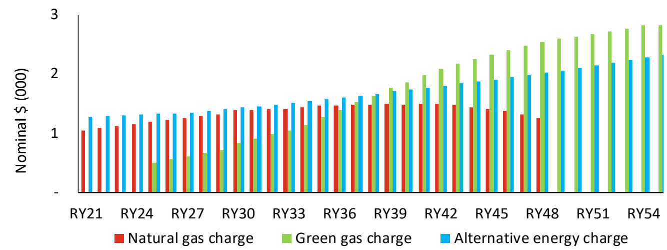
Industrial



**Natural gas charge > alternative energy charge in RY40*

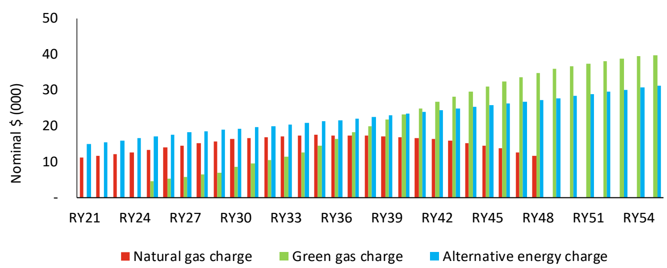
Optimistic re-purposing

Residential



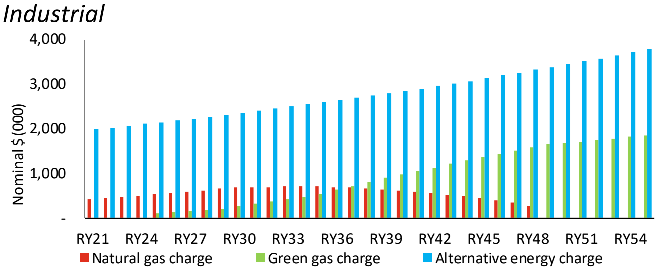
**Natural gas charge does not exceed alternative energy charge*

Commercial

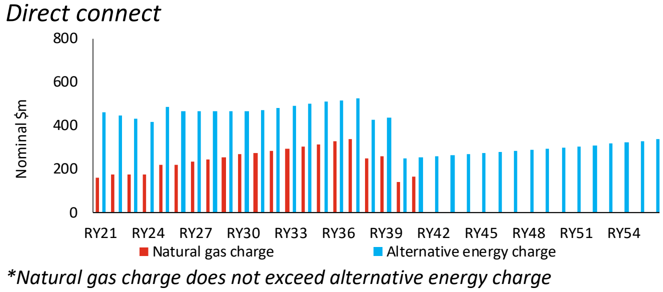


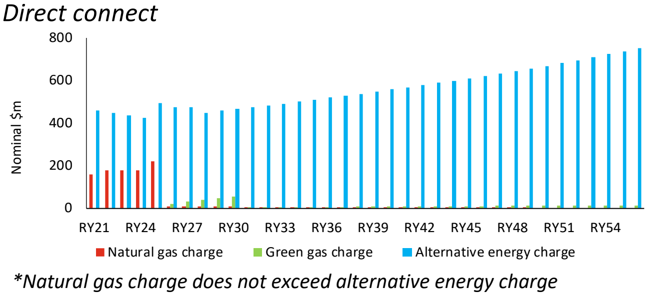
**Natural gas charge does not exceed alternative energy charge*

Industrial



**Natural gas charge does not exceed alternative energy charge*





Not: scales differ across the charts.

Sensitivity analysis

Table 4.7 analyses the sensitivity of per user natural gas charges under the fast wind-down scenario to changes in various drivers. Table 4.8 repeats the analysis for the optimistic repurposing scenario.

The analysis shows that:

- Increasing the **assumed willingness to pay** does not directly change the targeted natural gas charge – however, the charge actually recovered from consumers increases because customers are assumed to be less willing to switch to alternative energy.
- Increasing **demand** by increasing the number of connections means that costs can be spread over a larger customer base – and therefore the average targeted charge per connection reduces.
- As expected, increasing **expenditure** increases the per user charge – as transmission and distribution costs rise, so does the average connection cost per consumer because there is no corresponding impact on the alternative energy charge, natural gas charges rise relative to alternative energy charges.

TABLE 4.7: PRESENT VALUE OF NATURAL GAS CHARGES UNDER SCENARIO A: FAST WIND-DOWN - SENSITIVITIES

Sensitivity	Sector	Total PV of future per user charges (RY21 $000)	Average PV of per-user future charges (RY21 $000)	Final year
Base case	**Residential**	29	1	RY40
	Commercial	282	14	RY40
	Industrial	10,575	529	RY40
Demand + 20%	**Residential**	26	1	RY40
	Commercial	257	13	RY40
	Industrial	10,052	503	RY40
Expenditure: +10%	**Residential**	30	1	RY40
	Commercial	292	15	RY40
	Industrial	10,789	539	RY40

Table 4.8: Present value of natural gas charges under Scenario C: Optimistic repurposing - Sensitivities

Sensitivity	Sector	Total PV of future charges (RY21 $000)	Average PV of future charges (RY21 $000)	Final year
Base case	**Residential**	20	1	RY49
	Commercial	227	6	RY49
	Industrial	9,070	252	RY49
Demand + 20%	**Residential**	18	1	RY49
	Commercial	212	6	RY49
	Industrial	8,740	243	RY49
Expenditure: +10%	**Residential**	20	1	RY49
	Commercial	232	6	RY49
	Industrial	9,191	255	RY49

Limitations

This conceptual analysis is subject to the limitations noted in section 3.4.

Importantly, the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This model logic can be adjusted and is being reviewed.

Gas connection assumptions are particularly important to the analysis because they affect the customer base that allowed revenue is able to be spread over. Further work to understand what demand and gas connections may look like under alternative scenarios would be sensible.

4.5.5. Key insights

The initial analysis above and in the appendices suggests that a winddown of regulated gas pipelines exposes the gas consumers that remain to meaningful price increases as other consumers defect.

The pace of the winddown will clearly affect that risk – with a faster winddown leading to a faster price increases, which will encourage more rapid defection of consumers through the winddown.

Re-purposing gas infrastructure may help reduce avoid risk, although further work is needed to better understand what demand may look like under such a scenario.

Changes to regulatory settings or government support will also affect the price risk faced by gas consumers. The section consider how the regulatory and policy levers available to the Commerce Commission and the Government could affect the charges faced by consumers.

4.6. Question 5: Policy and regulatory levers

How could the implications for gas infrastructure owners and consumers be affected by future policy and regulatory decisions? What impact could different levers have (e.g., regulatory settings, government support)?

Box 7: Policy and regulatory levers | Summary

This section sets out results of 6 potential government and regulatory policy 'levers' tested by the working group. The working group recognises that there is a much broader range of potential levers and alternative ways in which these could be analysis.

The potential impact of the 6 levers on infrastructure owners and consumers is discussed below. Each lever is modelled independently of the other (i.e., multiple levers are not combined).

Impact on infrastructure owners

- Levers 1 and 2 | Accelerated depreciation – reduce by 50% the asset lives applying to new and existing assets from the start of the next DPP period. Asset stranding allowance –an ex-ante asset stranding risk allowance of 1% (of RAB) per year for the next DPP period onwards:
  - Result | both levers increase the present value of cash flows, although there is a partial offset later over the period if accelerated depreciation is used (as the RAB is lower) – accelerating depreciation reduces the RAB, while an ex ante allowance has no effect
- Lever 3 | RAB indexation is removed – whereby the Commerce Commission is assumed to remove indexation (i.e., CPI revaluations) of the RAB from the start of the next DPP period
  - Result | increases cash flows in earlier years and reduces it in later years, with the net effect being positive under the assumptions modelled
- Lever 4 | Government acquisition of regulatory asset bases (RABs) – whereby the Government is assumed to acquire 50%[17] of the existing RAB values at the start of the next default price path *and* no other levers are applied (such as the regulatory levers covered by 1, 2 and 3)
  - Result | gives a substantial positive cash inflow early in the modelling period, which is offset by lower cash flows over the remainder of the period (as the RAB is lower) – the net impact appears to be negative in present value terms under both the fast winddown and optimistic re-purposing scenarios modelled, however, it is likely that the conclusion will differ if demand were to adjust (e.g., from lower prices) or if a higher discount rate was used
- Lever 5 | Government subsidises green gas – whereby the Government subsidises 50% of the wholesale green gas costs incurred by gas consumers
  - Result | has only an indirect impact on cash flows and does not affect the RAB at all – under the optimistic re-purposing scenario it leads to an increase in cash flows to both transmission and

[17] The 50% assumption is somewhat arbitrary and adopted to illustrate the potential impact. *If* government acquisition is pursued as a lever, then the actual acquisition share could vary considerably and potentially up to 100%.

distribution as customers willingness to pay for gas transportation services increases (as gas consumers need to pay less on wholesale costs)

- **Lever 6** | Removing price or revenue caps
    - **Result** | increases cash flows, especially for distribution pipeline businesses, but does not affect the RAB.

Impact on Consumers

Gas consumers will benefit to the extent that the levers improve the prospect that gas infrastructure remains financially viable – as they retain the choice to consume reticulated gas.

However, gas consumers will be affected differently by the lever or levers adopting under the alternative scenarios. For instance:

- **Under the fast winddown scenario** | removing price or revenue caps appears to help reduce asset stranding risk. The other levers appear to have a lesser effect in the face of regulated annual changes that are projected to rise steadily as demand falls to zero by 2040. In practice, GPB revenue will be constrained by WTP and so even if regulated charges increase exponentially, they may not be recoverable from consumers (as by definition they would defect).
- **Under the optimistic re-purposing scenario** | for all levers charges are projected to increase gradually over time in nominal terms, without any exponential growth. This is because GPBs are assumed to continue as a going concern with demand to pay for allowed revenues.

4.6.1. Context

Sections 4.4 and 4.5 – which looked at questions 3 and 4 – considered potential implications for gas infrastructure owners and consumers under alternative winddown and re-purposing scenarios in terms of financial viability and energy affordability. This section considers how some of those solutions, or levers, could affect the implications for gas infrastructure owners and consumers.

4.6.2. Focus of analysis

The analysis in this section has an initial look at how different solutions open to the Government or the Commerce Commission could affect the financial outcomes faced by gas infrastructure owners and gas consumers, including by addressing cost recovery risk.

The analysis is of financial outcomes (as represented by the model) of certain potential solutions and considers the same horizon as that analysed in the previous sections. Importantly it does not directly consider other aspects of some solutions such as:

- benefits that may flow from greater policy and regulatory certainty being provided to stakeholders
- benefits from solutions that support innovation in the face of current uncertainty
- social costs and benefits

Given the breadth of potential solutions, this is only an initial analysis – it is not exhaustive and only considers a subset of the potential solutions identified in the Solutions Scoping Paper. Further work would be needed to fully assess the financial outcomes of all potential solutions in a robust and consistent way.

4.6.3. Prediction

The *first premise* is that Government financial support and Commerce Commission changes to allowed depreciation and compensation for asset stranding risk will meaningfully reduce the adverse impacts to gas infrastructure owners and gas consumers.

The impact that such levers will have on gas infrastructure owners and gas consumers will depend on:

- the nature and magnitude of the levers adopted, including as to the extent of any financial support or changes to allowed revenues, and
- who funds any financial support (e.g., tax payers, versus gas consumers, versus energy consumers more generally).

The *second premise* is that levers will affect gas infrastructure owners and gas consumers differently. It goes without saying that levers that improve financial viability by increasing or re-profiling allowed revenues will affect energy affordability faced by gas consumers. However, what is also likely – but much harder to model – is that improving financial viability will also benefit the gas consumers because gas infrastructure is more economic.

4.6.4. Quantitative analysis

Initial analysis

The initial quantitative analysis undertaken by the working group suggests that policy and regulatory levers could improve outcomes for gas infrastructure owners and gas consumers.

The 6 levers tested by the working group were:

- **Accelerated depreciation** – where the Commerce Commission is assumed to reduce by 50% the asset lives applying to new and existing assets from the start of the next DPP period
- **Asset stranding allowance** – where the Commerce Commission is assumed to allow an ex-ante asset stranding risk allowance of 1% (of RAB) per year for the next DPP period onwards
- **Government acquisition of regulatory asset bases (RABs)** – whereby the Government is assumed to acquire 50% of the existing RAB values at the start of the next default price path (DPP), with a one-off cash payment made to gas infrastructure owners[18]
- **Government subsidises green gas** – whereby the Government subsidises 50% of the wholesale green gas costs incurred by gas consumers
- **RAB indexation is removed** – whereby the Commerce Commission is assumed to remove indexation (i.e., CPI revaluations) of the RAB from the start of the next DPP period
- **Price or revenue cap removed** – whereby economic regulation is assumed to no longer apply and instead gas infrastructure owners set prices at the projected willingness to pay of gas consumers.

These had varying impacts on projected net cash flows to gas infrastructure owners, the RAB, and consumer charges. The impact also depended on the scenario considered (e.g., winddown or re-purposing).

Policy and regulatory levers – impact on infrastructure owners

In short, the impacts on net cash flows to infrastructure owners were:

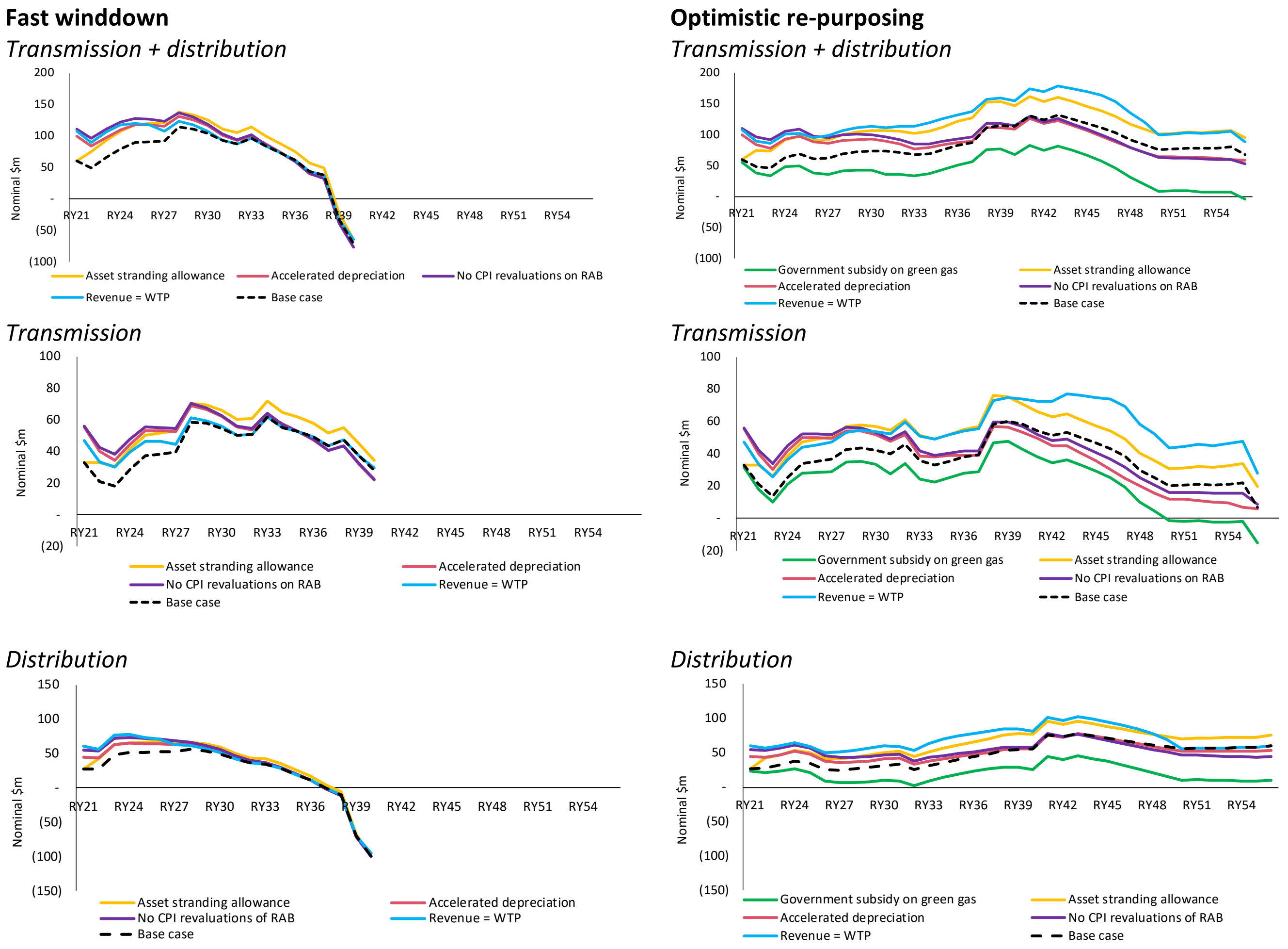
- accelerating depreciating or providing for an ex ante asset stranding allowance both increase the present value of cash flows, although there is a partial offset later over the period if accelerated depreciation is used (as the RAB is lower) – accelerating depreciation reduces the RAB, while an ex ante allowance has no effect
- removing indexation increases cash flows in earlier years and reduces it in later years, with the net effect being positive under the assumptions modelled

[18] A potential issue identified is that the acquisition of RABs by government may conflict with New Zealand's international obligations.

- Government acquisition gives a substantial positive cash inflow early in the modelling period, which is offset by lower cash flows over the remainder of the period (as the RAB is lower) – the net impact appears to be negative in present value terms under both the fast winddown and optimistic re-purposing scenarios modelled, however, it is likely that the conclusion will differ if demand were to adjust (e.g., from lower prices) or if a higher discount rate was used
- Government subsidy has only an indirect impact on cash flows and does not affect the RAB at all – under the optimistic re-purposing scenario it leads to an increase in cash flows to both transmission and distribution as customers willingness to pay for gas transportation services increases (as gas consumers need to pay less on wholesale costs)
- removing price or revenue caps increases cash flows, especially for distribution pipeline businesses, but does not affect the RAB.[19]

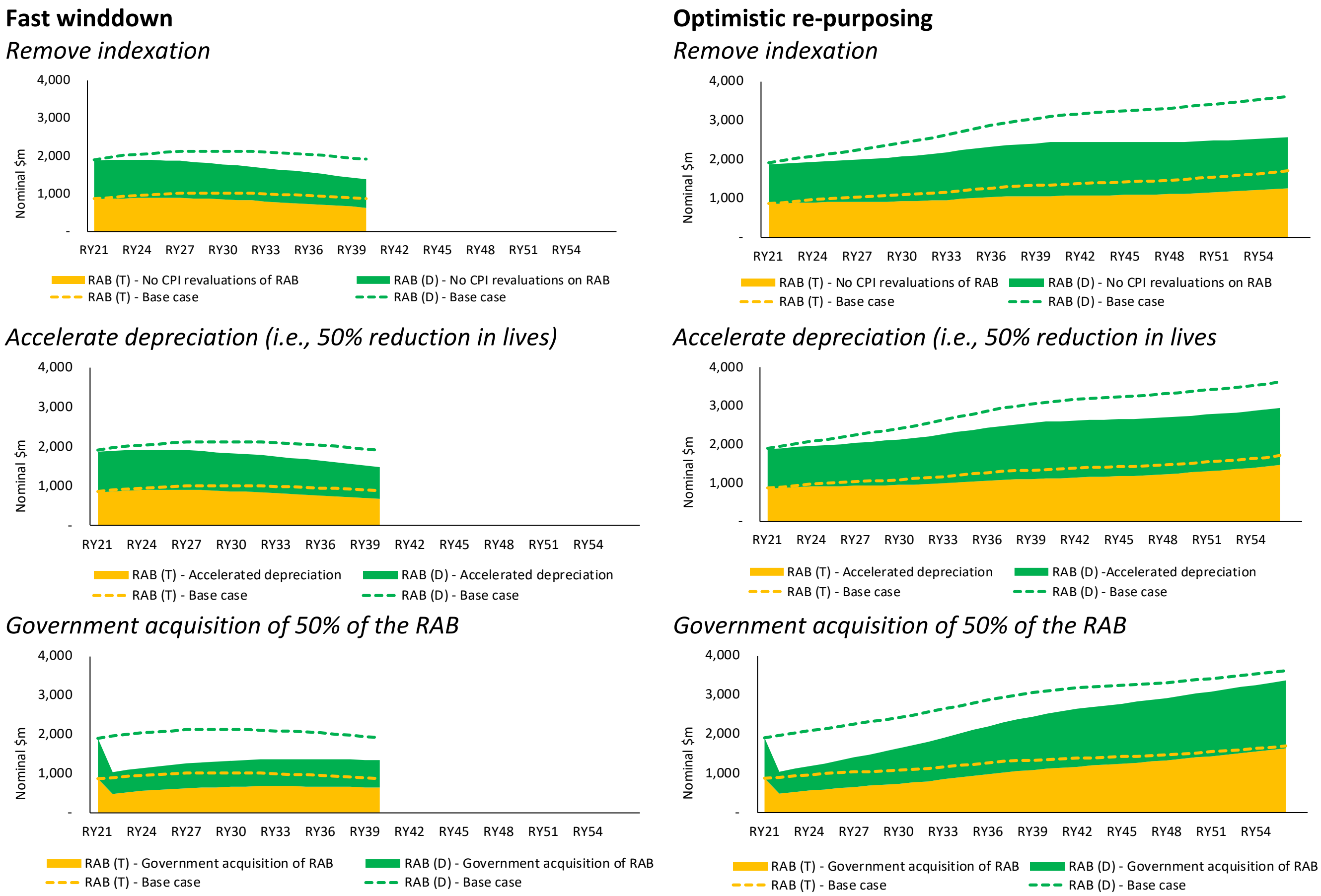
These cash flow and RAB impacts are summarised in FIGURE 4.10 and FIGURE 4.11. To make the impacts easier to visualise, the charts do not show the impact of government acquisition. However, the impact of that lever – and the others tested – are summarised in Table 4.9 and Table 4.10 further below.

FIGURE 4.10: NET CASH FLOWS



19 Although not modelled here, there is a risk that removing price or revenue caps could lead to network price increases that undermine the uptake of green gases by encouraging gas consumers to switch to alternative, cheaper, energy sources. Further work will be needed to better understand that dynamic.

FIGURE 4.11: REGULATOR ASSET BASE



Commerce Commission levers that increase BBAR (or allowed revenue) – such as accelerated depreciation, ex ante asset stranding allowances, or removing indexation – tend to increase annual charges, at least in the short term. Levers that bring forward recovery of the RAB will have an offsetting impact where subsequent charges are lower.

In contrast, the Government levers tend to reduce the annual charges faced by gas consumers. Government acquiring RABs reduces the network component of bills. Government subsidising wholesale green gas costs reduces the delivered price of green gas.

Unsurprisingly, removing price or revenue caps increases the prices paid by gas consumers, at least in the short term. The longer term impact is less clear. The ‘simplistic’ assumption in the initial analysis is that gas infrastructure owners would price their services at the willingness to pay of gas consumers. Under the base case, it is assumed that they would price to recover regulated revenue. In practice, however, it may be unrealistic to assume that gas infrastructure owners could realise regulated prices if they get too high.

Moreover, what is not modelled here is the impact that these levers may have on consumer demand, and therefore the potential for consumers to benefit from levers that increase gas consumer willingness to pay. For instance, a green gas subsidy may encourage more gas consumers to remain on the gas networks. Government acquiring RABs may encourage consumers to defect less quickly under a winddown scenario.

Policy and regulatory levers – impact on consumers

The illustrative impact of relevant levers on annual charges is shown in **FIGURE 4.12**. The impact is shown for residential, commercial, and industrial consumers across both the fast winddown and optimistic re-purposing scenarios.

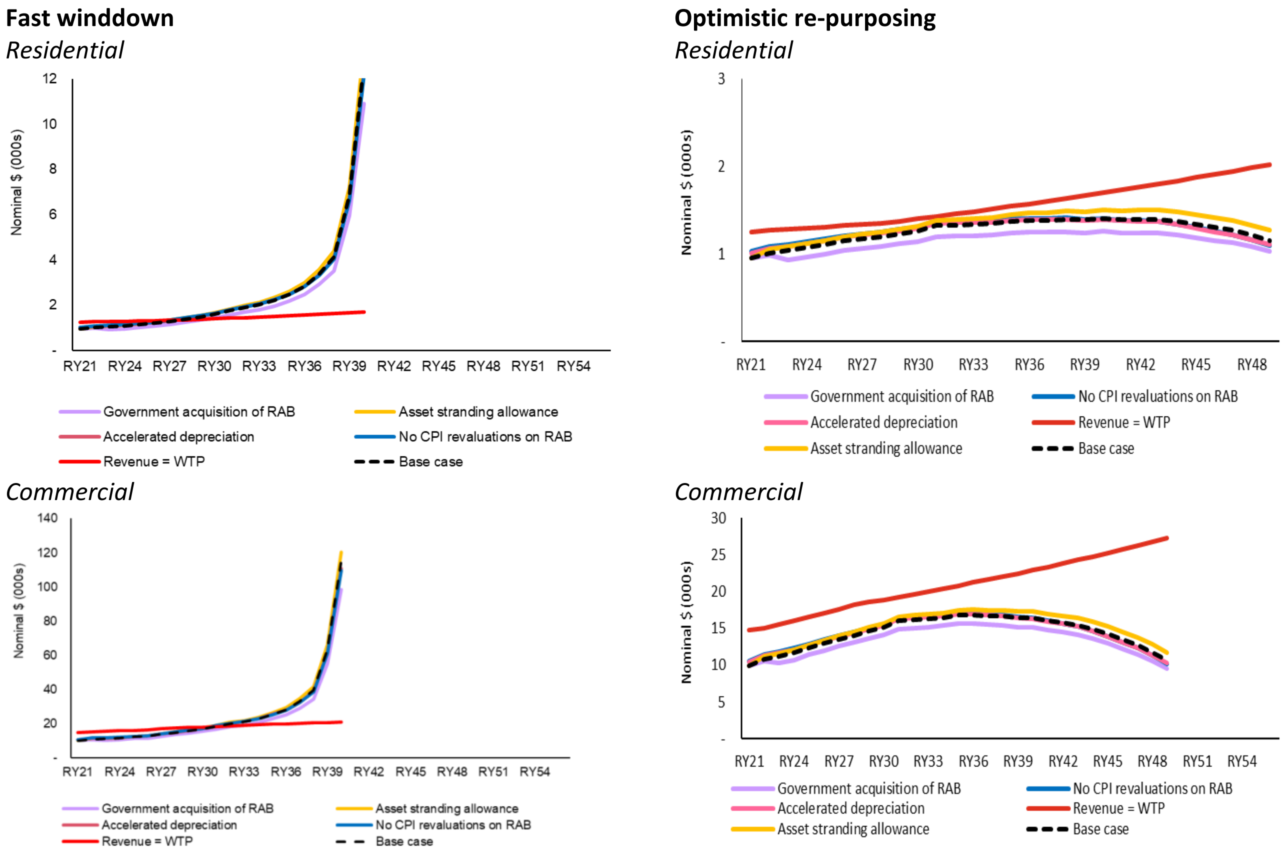
Under the fast winddown scenario, none of the levers appear to avoid the base case projection that regulated annual charges will increase exponentially as demand falls to zero by 2040, *except* where price and revenue caps are removed (as illustrated by red 'Revenue = WTP' line). Except in that case, projected charges are remarkably similar – which suggests that *if* there is a fast winddown, then there will be significant upward pressure on annual charges. In practice, however, GPB revenue will be constrained by WTP and so even if regulated charges increase exponentially, they may not be recoverable from consumers (as by definition they would defect).

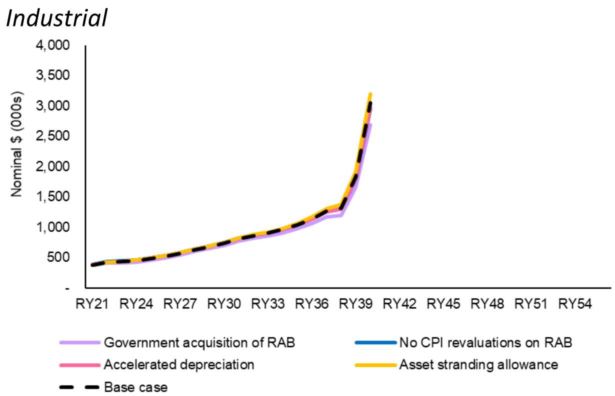
In contrast, under the optimistic re-purposing scenario, charges are projected to increase gradually over time in nominal terms under all levers, without any exponential growth, before declining again towards the end of the period. This is because GPBs are assumed to continue as a going concern with demand to pay for allowed revenues. However, consumption of gas falls over time under the optimistic repurposing scenario, contributing to a fall in the per user charge of gas.

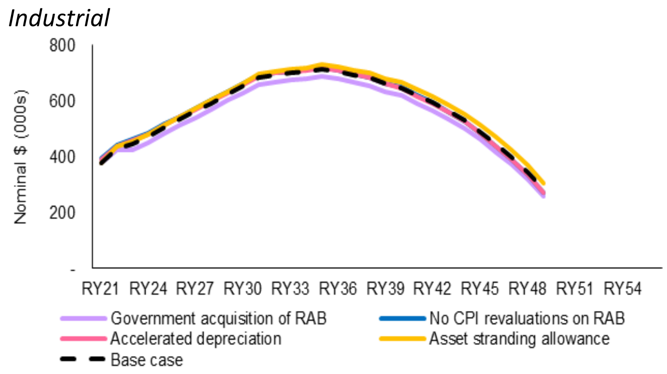
The charts also show that:

- where revenue and price caps are removed and charges are set to WTP (the red line), those charges remain higher than if the other levers are used instead
- projected charges are lowest if the Government acquisition lever is used (the purple line) – which occurs because this would reduce the revenue needed for GPBs to recover their efficient costs.

FIGURE 4.12: ANNUAL CHARGES PER CONSUMER







Note: scales differ across the charts.

Sensitivity analysis

Given the large number of permutations, sensitivity analysis was not undertaken. However, the *directional* impact of the sensitivities considered above are expected to apply equally to the scenarios and levers considered in this brief.

The impact on net cash flows and terminal RAB are shown in Table 4.9 and Table 4.10 below.

TABLE 4.9: PRESENT VALUE OF CASH FLOWS AND TERMINAL RAB BY REGULATORY LEVER – FAST WINDDOWN

Regulatory lever	Sector	PV of future net cash flows (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
Base case	Transmission	558	332	890
	Distribution	385	423	808
	Total	943	754	1,698
Government acquisition of RAB	Transmission	636	176	812
	Distribution	576	226	801
	Total	1,212	401	1,613
No CPI revaluations of RAB	Transmission	694	237	930
	Distribution	548	305	853
	Total	1,241	542	1,783
Accelerated depreciation	Transmission	675	251	926
	Distribution	487	332	819
	Total	1,163	582	1,745
Asset stranding allowance	Transmission	699	214	913
	Distribution	511	317	828

Regulatory lever	Sector	PV of future net cash flows (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
	Total	1,209	531	1,741
Increased Demand	**Transmission**	556	332	888
	Distribution	380	423	803
	Total	936	754	1,691
Revenue = WTP	**Transmission**	627	332	959
	Distribution	547	423	970
	Total	1,174	754	1,929

TABLE 4.10: PRESENT VALUE OF CASH FLOWS AND TERMINAL RAB BY REGULATORY LEVER – OPTIMISTIC RE-PURPOSING

Regulatory lever	Sector	PV of future net cash flows (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
Base case	**Transmission**	641	327	968
	Distribution	751	367	1,119
	Total	1,392	694	2,086
Government acquisition of RAB	**Transmission**	568	263	830
	Distribution	822	273	1,096
	Total	1,390	536	1,926
No CPI revaluations of RAB	**Transmission**	788	240	1,029
	Distribution	943	253	1,196
	Total	1,731	493	2,225
Accelerated depreciation	**Transmission**	737	281	1,018
	Distribution	871	283	1,154
	Total	1,608	564	2,173
Asset stranding allowance	**Transmission**	868	145	1,013
	Distribution	1,044	134	1,178

Regulatory lever	Sector	PV of future net cash flows (RY21 $m)	PV of terminal RAB (RY21 $m)	Total PV (RY21 $m)
	Total	1,912	279	2,191
Increased Demand	**Transmission**	652	327	979
	Distribution	739	367	1,106
	Total	1,390	694	2,085
Revenue = WTP	**Transmission**	924	327	1,251
	Distribution	1,196	367	1,564
	Total	2,120	694	2,814

Limitations

This conceptual analysis is subject to the limitations noted in section 3.4.

The initial analysis only considered 6 potential policy and regulatory levers, or options. The working group's recently finalised Solutions Scoping Paper identified 35 potential options. The analysis also only considered 1 variant of each of the 6 levers. In practice, these levers could be applied in different ways (e.g., different levels of Government acquisition).

Also, the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This model logic can be adjusted and is being reviewed.

Gas connection assumptions are particularly important to the analysis because they affect the customer base that allowed revenue is spread over. Similarly, willingness to pay assumptions are particularly important to the analysis because they affect the amount of allowed revenue that regulated gas pipelines are projected to recover. Further work to understand what demand and gas connections may look like under alternative scenarios would and to better understand gas consumers' willingness to pay would be sensible, including to better assess non-price factors that influence gas consumers decisions to use gas or alternative energy sources.

4.6.5. Key insights

The initial analysis above suggests that policy and regulatory levers can positively affect the outcomes faced by gas infrastructure owners and consumers.

Unsurprisingly, the magnitude of those affects depends on whether gas infrastructure is being wound down or repurposed. For instance, with the green gas subsidy only benefit gas infrastructure owners and gas consumers under a re-purposing scenario. The magnitude is also affected by how those levers are applied (e.g., how much accelerated depreciation is applied).

5. POTENTIAL FUTURE ANALYSIS

This *Initial Analysis Paper* presents some initial conceptual analysis undertaken of 5 key questions about the future of gas infrastructure posed by the working group. But it is by no means complete or exhaustive – further analysis is undoubtably warranted.

The conceptual analysis rests on a model and preliminary inputs developed by the working group, including demand, pricing, and expenditure assumptions. The model analyses potential impacts on gas consumers, gas infrastructure businesses, and Government over a 35 year horizon under alternative scenarios.

In doing so, it extends from the winddown and re-purposing scenarios considered in the initial *Findings Report*. Preparing this report at this time 'draws a line' under this initial analysis work and provides an opportunity to consider what further analysis work could or should be undertaken by the working group or others.

In the **short term**, further analysis could be undertaken to:

- consider questions raised by the Commerce Commission's draft decision on the 2022 gas default price-quality path (DPP)
- input to the Government's forthcoming energy strategy, or
- assess the potential impacts of the emissions reduction plan when published in May 2022.

Proactive analysis that could also be undertaken to:

- extend and refine the modelling to consider:
    - interactions between projected prices – including network prices – and demand for gas transportation services and between projected cash flows and GPB expenditure and operational decisions, such as, whether to shutdown parts of their networks
    - the impact on end use energy costs and consumer choices of the relative costs of transporting energy as a gas rather than in other forms, such as solid biomass or electricity
    - potential competitive market effects on supply chain margins, such as producer and retail margins
- assess the impact on carbon emissions of alternative market scenarios
- assess a broader range of scenarios or levers (such as other options considered in the working group's *Options Scoping Paper*)
- test in more detail what a realistic re-purposing scenario might look like, or what conditions are needed for it to be a success
- develop one or two realistic packages of solutions, building on the Options Scoping Paper, and testing these using the financial analysis model
- review and potentially respond to the Commerce Commissions draft and final DPP decisions in February and May 2022, or
- refine and test the analysis with key stakeholders – such as customers and/or energy sector commentators – which could, for example, be based a broad survey of stakeholder views on the future of gas infrastructure in New Zealand.

The working group is currently considering what further analysis if may undertake, if any.

Appendices

Summary

This part of the Initial Analysis Paper includes four appendices:

Appendix A: Model description

Appendix B: Glossary and Abbreviations

APPENDIX A. MODEL DESCRIPTION

This appendix describes the model used by the working group to undertake its initial analysis.

A.1. Summary

At its core, the model is a cash flow model. It assesses the cash flows to gas infrastructure owners and gas consumers over a 36-year forecasting period. It relies on a range of inputs and assumptions. It also simplifies some of the real-world dynamics that will play out in practice to approximate the potential cash flow impacts.

As with all modelling, there is always room to improve. Further work could be done to improve the quality of inputs and assumptions. The model could be refined to model, dynamically, relationships:

- between projected demand and prices faced by gas consumers, and
- between projected expenditure by and cash flows or returns to gas infrastructure owners.

However, the working group considers that the model provides an appropriate starting point for an *initial* foray into the analysis questions identified in 2.4 and considered in section 4.

The remainder of this appendix briefly outlines the model purpose, scope, and structure. It also notes the scenario capability and key limitations. The model is supported by a model user guide, which has not been included in this paper.

A.2. Purpose

The overarching purpose of the Model is to help understand the financial impact on gas consumers and GPBs of future scenarios for gas infrastructure in New Zealand. The Model helps answer key policy, regulatory and pricing questions related to the future of GPBs such as:

- What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk?
- How is the cost recovery risk affected by the potential for re-purposing and differences in willingness to pay for consumer groups?
- How is cost recovery risk affected by regulatory levers (eg. alternative depreciation, stranding allowance, regulatory WACC, etc.) and policy levers (e.g., Government support to networks and/or consumers)?
- How do these implications vary by distribution and transmission?
- What are the financial implications to gas consumers across consumer groups (residential, commercial and industrial)?

A.3. Scope

To achieve the purpose, the model assesses cash flows to gas infrastructure owners and gas consumers over a 36-year forecasting period, starting with regulatory year 21 plus an additional 35 years. It can be used to assess the consequences of various potential regulatory and policy decisions (or levers) on each gas pipeline business' revenue, net cash flows (before financing and tax), and regulatory metrics (e.g., RAB, RIV or ROI).

The model allows outcomes to be compared under different scenarios by applying specific flexes on:

- regulatory levers – such as, alternative depreciation, asset stranding allowance, RAB indexation, WACC
- policy levers – such as, Government support to consumers and networks, deregulation
- consumer connection profile
- expenditure profile (capex and opex)

- other consumer impacts – such as, BBAR allocation to consumer group, wholesale gas prices, alternative energy pricing.

The model also incorporates further sensitivity testing on inputs including capex/opex, consumer connections/demand. It produces outputs for each gas pipeline business individually and in aggregate.

A.4. Structure

The Model is made up of two core modules which are dynamically linked and contained within the same workbook:

- **BBAR module**: estimates the regulatory asset base (RAB), regulatory tax asset value (RTAV) and regulatory investment value (RIV) and building blocks allowable revenue (BBAR) of a chosen GBP.
- **Consumer Impacts module**: calculates the annual cost recovered per consumer, as a combination of transmission and distribution BBAR, wholesale gas costs and a retailer margin, capped at the annualised alternative energy costs. This module also calculates the GBPs' revenue, cash flows, regulatory tax allowances and return on investment (ROI).

Each module has three components, consisting of inputs, calculations and outputs.

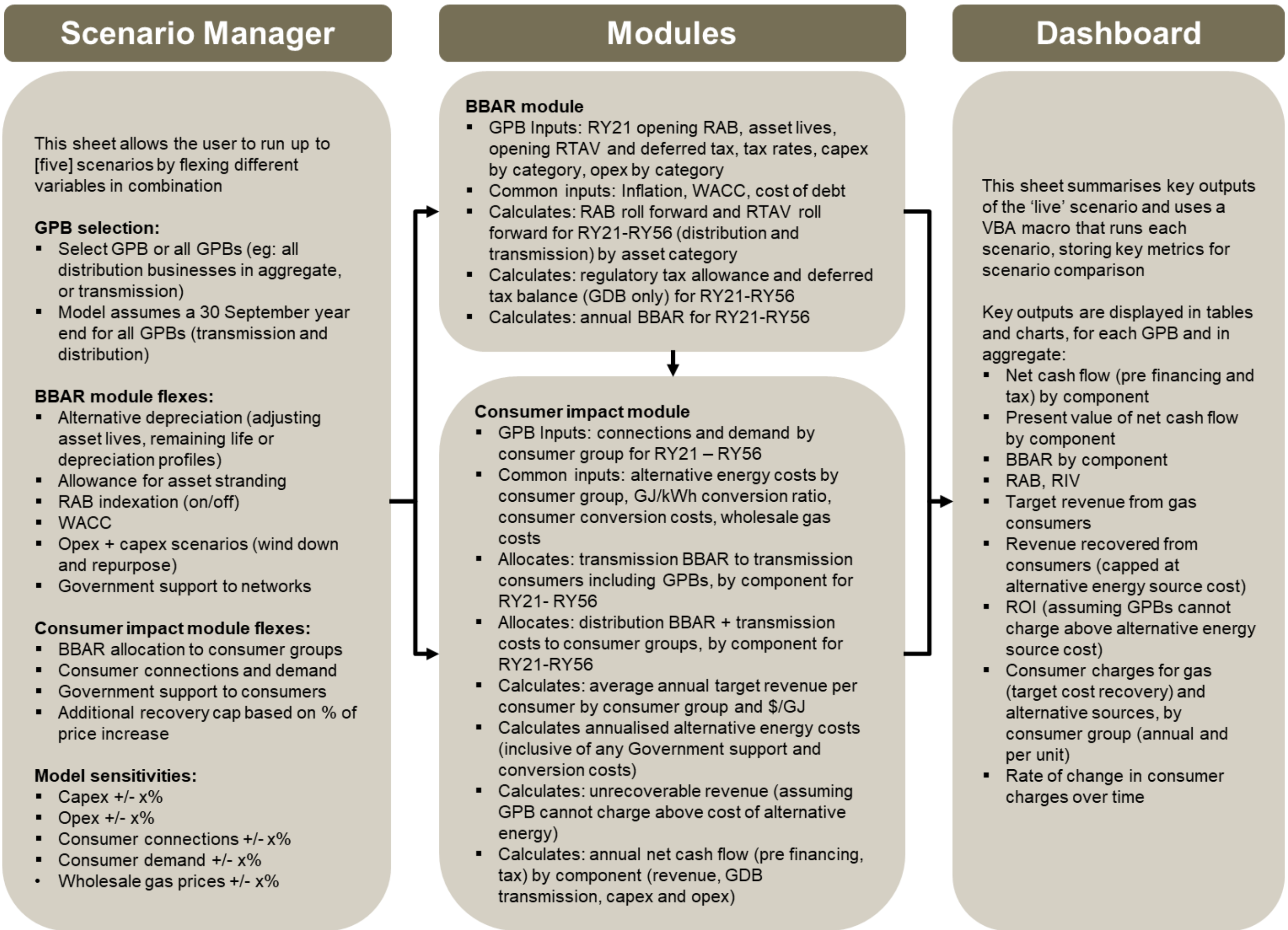
The model also contains:

- **ScenaROI manager** – which allows the user to select from a comprehensive range of scenarios, flexes and sensitivities and a dashboard which displays key model outputs
- **Maximum allowed revenue (MAR) calculation capability** – which can be used to assess alternative options for smoothing BBAR revenues.

The model start date is 1 October 2020 to align with the most recent published GPB regulatory data. The model forecasts annual cash flows over a 36-year period, with a 30 September year-end to align with the DPP. Five-year regulatory periods are identified in the model, to allow for any changes in regulatory settings that apply from the beginning of a regulatory period.

Figure A.4.1 illustrates the high-level structure of the Model (excluding certain modules and logic recently added such as MAR and financing calculations).

FIGURE A.4.1: MODEL STRUCTURE



A.5. Scenarios and sensitivities

A key part of the model's capability is functionality to test the impact of a range of scenarios and sensitivities on the results.

This capability is managed within the scenario manager and there are four different categories of scenarios/sensitivities that can be changed:

- **Market scenarios** – six defined scenarios relating to the overall market outcome for gas.
- **Model scenarios** – five customisable model scenarios based on a range of regulatory and other factors.
- **Sensitivities** – percentage-based increases or decreases applied to specific inputs.
- **GPB selection** – choice of whether outputs should be calculated for a specific GDB (First Gas, GasNet, Powerco or Vector) or for the total distribution market.

The scenario manager lets the working group easily switch between any combination of scenarios and sensitivities under the above categories.

The market and model scenarios considered by the working group as part of the initial analysis are discussed in the next two sub-sections.

A.5.1. Market scenarios

The Model contains six different market scenarios relating to the overall market outcome for gas. Two scenarios involve a wind-down of gas infrastructure and four scenarios relate to re-purposing natural gas infrastructure for green gas or hydrogen. The key inputs that differ across market scenarios are gas throughput and number of connections as well as expenditure forecasts provided by GPBs.

The six market scenarios are described in Table A.5.1 below. The first four (A, B, C, and D) are considered in the paper. The last two (E and F) were left out to simplify the analysis.

TABLE A.5.1: MARKET SCENARIO DESCRIPTIONS

Market scenario	Description
A. Fast wind-down scenario	Gas throughput and connections reduce rapidly, with gas consumers transitioning to alternative energy sources (e.g., residential and commercial users switch to electricity, no new connections), incurring relevant conversion costs with pipeline use ceased by 2040
B. Slow wind-down scenario	As per fast wind-down scenario, except gas throughput and connections reduce more gradually with pipeline use cease by 2050
C. Optimistic hydrogen re-purposing	Gas throughput rapidly transitions from natural gas to hydrogen gas or biomethane. By 2050, green gas throughput will be 50% of existing throughput and natural gas throughput will be zero
D. Pessimistic hydrogen re-purposing	As per optimistic hydrogen re-purposing, except that by 2050 green gas throughput is 20% of existing natural gas throughput
E. Capital light- re-purposing	Infrastructure investment and conversion costs for re-purposing are minimised by the gas infrastructure being repurposed to handle some combination of biomethane and hydrogen blend
F. re-purposing pivot	Start with the slow wind-down scenario for the first 10 years, then pivot to the pessimistic hydrogen re-purposing scenario

A.5.2. Model scenarios

Separate from the market scenarios described above, the model allows the working group to compare outputs across up to five model scenarios. The model scenarios can be created within the scenario manager by assigning and flexing different scenario design variables in combination.

The design variables impact either the BBAR module or the consumer impact module and relate to a wide range of factors including regulatory settings, government subsidies and market parameters. The full set of design variables built into the Model are described in the Table A.5.2 below.

TABLE A.5.2: MARKET SCENARIO DESCRIPTIONS

Module impacted	Design variable	Description
BBAR module	WACC	Ability to switch between a weighted average cost of capital (WACC) based on current regulatory settings and an alternative WACC.
BBAR module	Government subsidy	On/off switch for government subsidy to networks. The amount of the subsidy (as a percentage of RAB) for any given year can be specified as an input. When the switch is turned to on, GPBs are assumed to receive a cash payment equal to the value of the specified portion of RAB in the specified year. RAB is reduced by the same value and RAV is also reduced by an equivalent proportion. The after-tax cash flow impact is accounted for in net cash flows.
BBAR module	Ex-ante allowance for asset stranding	On/Off switch to apply an ex-ante allowance for asset stranding. Calculated as a customisable percentage rate applied to mid-period RAB, allowing GPBs to recover a portion of RAB in a regulatory year as BBAR.
BBAR module	Alternative Depreciation	On/Off switch for a customisable percentage of RAB depreciation (with a default 100% being equivalent to depreciation based on an asset's remaining useful life profile). Contains functionality to treat existing and commissioned assets separately.
BBAR module	RAB revaluations	On/Off switch for RAB revaluations based on CPI, with the functionality to choose in which regulatory year revaluations are turned off.
BBAR module	Escalators	Functionality to choose how opex and capex are inflated over the forecast period, with the option to use a Consumer Price index, a weighted Labor Cost index/Producer Price index, or a Capital Goods Price index.
Consumer Impact Module	MAR allocation	Functionality to calculate MAR matched to consumption profile, or matched to a manually inputted profile.

Module impacted	Design variable	Description
Consumer Impact Module	BBAR allocation	Functionality to choose how BBAR is allocated to consumer groups. Includes a custom (manual) option, an option based on existing revenue allocation, and a recovery led option (distribution only)
Consumer Impact Module	Government support to consumers	Functionality to reduce the conversion cost component of alternative energy charges through a government subsidy, at a customisable percentage.
Consumer Impact Module	Annual recovery cap	Functionality to cap annual increases in consumer charges to a customisable percentage, for both transmission and distribution charges.
Consumer Impact Module	Allocation of unrecoverable revenue	Functionality to reallocate a portion of distribution unrecoverable revenue to transmission.
Consumer Impact Module	Willingness to pay margin	A customisable percentage that functions as a margin on top of the total alternative energy charge, signifying consumer preference towards gas.

A.6. Key assumptions and limitations

The model and conceptual analysis depend on a wide range of assumptions and inputs – these are subject to important limitations.

Key assumptions and limitations include:

- **Interaction between demand and prices** – the model is static in that it does not endogenously model the relationship between demand for gas and prices, which means that it may miss important insights that could be gained if projected demand were to update automatically within the model if there were a change in projected prices
- **Interaction between cash flows and pipeline expenditure** – the model also does not model the relationship between projected cash flows and returns to infrastructure owners and the expenditure decisions that they make, which means that it may also miss important insights that could be gained if projected expenditure were to update automatically within the model if there were a change in projected cash flows (e.g., because infrastructure owners assessed that such expenditure was not economic)
- **Revenue allocation** – the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This logic means that the revenue obtained when modelling results for an individual GPB may not match that GPB's share of revenue when modelling the sector as a whole. This model logic can be adjusted in future versions. This model logic can be adjusted in future versions

- **Regulatory period length** – the model assumes regulatory (DPP) periods of 5 years. This may change in future, as indicated by the Commerce Commission's recently announced intent to set the length of the next DPP period to 4 years.
- **Willingness to pay** – an additional margin was added to projected to economic willingness to pay for gas to ensure that unrecoverable revenue is zero or close to zero for the first three modelling years for all GPBs to approximate the impact of non-price factors, including consumer switching 'stickiness'. This is further discussed in section A.7 below.
- **Net debt approximation** – the Model calculates a proxy measure for 'net debt'. This measure is not meant to forecast actual debt levels for a given GPB, but rather illustrate financing impacts and trends under a given scenario. More detailed financing modelling capabilities can be built into future versions of the model.
- **Price limits** – the 10% annual price increase cap feature has currently been switched off in the model so that the impact of different regulatory settings can be more easily observed.
- **Forecast inflation** – forecast inflation has been set to 2% for all years to reduce short-term inflation forecast volatility.
- **Regulated WACC** – the WACC has currently been set to be consistent with the Commerce Commission's cost of capital determination for disclosure year 2022 for information disclosure regulation for all model years.

A.7. Willingness to pay

As noted in section 3.4, an important component of the modelling is WTP – which is a prediction as to how much consumers are willing to pay for delivered gas before they would choose not to consume (e.g., to take up alternative energy sources or otherwise cease using cease).

Concept Consulting has been doing some work to look at the WTP of various types of gas consumers by comparing the costs that they may face for different energy sources, including gas. However, WTP is notoriously difficult to assess, let alone forecast accurately – which means that estimates are generally based on a suite of assumptions.

For the initial analysis, the working group has modelled the WTP for each consumer type, under each scenario as the sum of:

- the projected price of alternative energy provided by Concept Consulting
- the cost of converting from gas to alternative energy, including any make good costs, also provided by Concept Consulting, and
- an assumed markup (of 10%) to reflect non-price factors, such as consumer stickiness,[20] amenity value, and other desirable characteristics (e.g., instantaneous hot water).

Conversion costs are assumed to be spread evenly over a period of time – namely, 5 years for distribution customers and 10 years for transmission direct connect customers. An equal annual payment amount is set so that the total present value is equal to the total conversion cost provided by Concept Consulting.

Of the three components listed above, the markup for non-price factors is likely to be most uncertain. Anecdotal evidence of gas consumer behaviour indicates that the mark-up is likely to be positive. For example, historical observation suggests that some gas consumers continue to use gas even though it would appear to make sense, economically, to switch to alternative energy sources.

However, a precise estimate is difficult to determine. A 10% assumption was adopted as a placeholder intended to align with the intuition mentioned above, but it is not based on any empirical analysis.

20 Consumer stickiness is the phenomenon whereby consumers are tend to be slow to switch from one supplier to another even though it is economically sensible to do so (e.g., switching energy retailers or telecom providers).

A further limitation of applying a single mark-up for non-price factors is that variation between customer groups is not captured. For example, it is possible that factors such as consumer stickiness are stronger for residential versus commercial or industrial customer types.

Further work could be done to derive a more precise estimate of the WTP, especially around the uncertain mark-up for non-price factors. For example, analysis could be performed to better understand how non-price factors that have historically affected demand for gas (including differences across customer groups) and what this may mean for gas demand in the future. Such analysis is likely to involve significant complexity.

APPENDIX B. GLOSSARY AND ABBREVIATIONS

Term	Definition
BBAR	Building Blocks Annual Revenue
CPI	Consumer Price Index
DPP	Default Price Path
GDPs	Gas Distribution Businesses
GJ	Gigajoules
GPBs	Gas Pipeline Businesses
GIC	Gas Industry Company
PwC	PricewaterhouseCoopers
PV	Present Value
RAB	Regulatory Asset Base
ROI	Return on Investment
RY	Regulatory Year
WACC	Weighted Average Cost of Capital
WTP	Willingness To Pay