Key issues for Gas DPP4 reset

Report for Vector | 24 July 2025

Contents

Tables

Figures

1 Introduction

1.1 Background and context

The current default price-quality path (DPP) for gas pipeline businesses, which was set by the Commerce Commission ("the Commission") in 2022, is due to expire on 30 September 2026.

The Commission must set a new DPP to apply over the five years from 1 October 2026 (the period known as DPP4). The Commission has commenced its review for DPP4. On 26 June 2025, the Commission published its Issues Paper, which outlines the context for DPP4, the issues that the Commission considers are relevant to DPP4 and the ways that the Commission proposes to set the DPP to promote the long-term benefit of consumers of gas pipeline services.

1.2 Purpose of this report

Vector has engaged Frontier Economics to provide our views on key matters raised in the Commission's Issues Paper. This expert report provides our views on the following matters:

- The management of trade-offs between capital expenditure and operating expenditure during DPP4 and beyond, noting uncertainty about the life of gas pipelines will motivate an increase in maintenance over asset replacement.
- The form of control that is applied in the context of how best to treat the within-period risk of decreasing gas usage and connections.
- How stranded asset risk is managed for gas distribution businesses (GDBs), including through the use of accelerated depreciation . This includes a consideration of whether circumstances have changed since this issue was previously considered by the Commerce Commission that warrant a different approach.
- The eventual retirement of gas pipelines will cause decommissioning and remediation costs to be incurred. We consider what approach should be taking to recovering these costs.

2 Managing capex/opex trade-offs

2.1 Introduction

This section considers the management of capex/opex trade-offs for GDBs during DPP4 and beyond.

Vector's gas distribution network is facing unprecedented levels of uncertainty related to the future of gas demand in New Zealand. Vector, like other GDBs in New Zealand, needs to take prudent steps to ensure it continues to deliver safe and reliable services, while also managing the risk of asset stranding.

One approach to manage this risk is to reduce capital expenditure (capex) on asset replacement and replace this with increased operational expenditure (opex) on asset maintenance. In the context of the Commission's current regulatory framework, reducing capex with a corresponding increase in opex is called a capex/opex trade-off.

It is important that the Commission recognises these circumstances in its approach to DPP4. GDBs in New Zealand already face reduced incentives for incurring capex due to market uncertainty and the associated stranded asset risk. If opex allowances are also set too low it would materially increase the risk that the businesses would be unable to fund expenditure required to maintain service performance.

The remainder of this section summaries the initial views put forward by the Commission and then provides our views on the principles relevant to capex/opex trade-offs and the preferred approach for establishing opex allowances for DPP4.

2.2 Commission position

The Commission's Issues Paper acknowledges that in the current environment GDBs will likely need to consider capex/opex trade-offs as a step change to opex. In this regard, it is consulting on if and how it uses the base-step-trend (BST) model for opex in DPP4. Specifically:

- If it were to continue using the BST model, it is considering what adjustments may be needed to adapt to the current uncertainty regarding volumes of gas delivered and greater use of opex instead of capex to maintain networks.
- If the Commission wasn't to use the BST model, it is considering alternative approaches including relying on Asset Management Plan (AMP) forecasts and adopting a more top-down or bottom-up approach to scrutinise the basis on which these have been prepared.

In particular, the Commission is seeking views on:

- the most appropriate approach for opex, either BST or an alternative
- how GPBs have been making or considering capex/opex trade-offs in their expenditure forecasts and whether they are updating those considerations in preparing their upcoming AMP updates
- how it could factor in capex/opex substitutions in setting the expenditure allowances under the BST approach and whether its existing criteria are appropriate; and
- if network scale trends for GDBs should be adapted for the current context of declining volumes delivered, and if so, how.

2.3 Vector's 2025 Asset Management Plan

Vector's 2025 AMP includes updated modelling which shows new connections stopping in 2028-29 and an increase in disconnections. This results in a decline in net connections to the network in 2025-26, and the overall gas volume continuing to decline, but at a faster rate.

Vector notes it is taking prudent steps to optimise its asset management strategies to maintain network safety and reliability, while reducing asset stranding risk. This includes reducing capex on asset replacements and increasing opex on maintenance. It considers the benefits of this approach include:

- enabling more targeted, risk-based maintenance strategies
- helping financial capital management in an environment of high uncertainty; and
- allowing flexibility to adapt to changing market conditions.

In conjunction with this approach Vector is introducing, in a staged manner, camera-based technology which enables increased maintenance and inspection.[1]

2.4 Frontier Economics' views

The expected decline in net connections to the gas network and associated fall in overall gas volumes brings in to question the remaining life of the gas network in New Zealand. This uncertainty makes asset management strategies more complex, with the need for GDBs to adapt to maintain network safety and reliability, while managing asset stranding risk.

Robust asset management systems monitor, maintain and replace assets using a risk-based lifecycle decision framework. When assessing capital investment options, the aim is to optimise lifecycle (capital and operating) costs while continuing to operate the network safely and effectively. Normally these decisions are made under the expectation of a stable network.

In the current circumstances an economically rational approach is to:

- reduce capex on asset replacements (where these costs are recovered over the life of the asset); and
- increase opex on maintenance (which is recovered during a single year).

Increasing maintenance opex can be more expensive over the long term, however it provides flexibility to adapt to future market conditions and makes economic sense if the network has a shorter remaining life.[2] In other words, choosing opex over capex can be a prudent investment to achieve the lowest sustainable cost of delivering pipeline services in an environment of uncertainty regarding the future life of the assets.

2.4.1 Overall approach to setting the opex allowance

In the current context, continued application of the BST approach poses challenges. The BST approach is best suited to networks that are stable or growing. However, when a network is expected to decline, and there is considerable uncertainty around the pace at which this may occur:

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1 Vector, 2025—2035 Gas distribution asset management plan, p 5.

2 The Australian Energy Regulator has also recognised this in its 2021 Information paper, AER, *Regulating gas pipelines under uncertainty,* Information paper, November 2021, p 52., available at: https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-%20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf

- The ‘base’ year under the BST approach, normally the most recent regulatory disclosure year, will be unlikely to represent a realistic expectation of the efficient and sustainable ongoing level of opex required to provide network services in the next regulatory period.
- ‘Step’ changes can account for revised asset management strategies that increase opex. However, even where they are provided for under the regulatory framework, they can be challenging to justify given the extent of uncertainty around changes in the network.
- ‘Trend’ factors relating to output growth and productivity require special consideration:
    - both output and customer connections will likely trend downward, however this will not reflect the ongoing costs of managing the network which are largely fixed; and
    - productivity savings become increasingly difficult to achieve as the network stops growing and customer numbers decline.

In principle, with adequate flexibility in its application, a BST approach may continue to provide an appropriate opex allowance. However, the emphasis on the step change component of this approach becomes critical.

The Commission flagged applying scrutiny to GPB forecasts in AMPs as an alternative to, or in conjunction with, the BST approach. AMP forecasts are publicly available, and provided the Commission can effectively scrutinise these, we consider this is also a reasonable and pragmatic approach for DPP4. It would provide the Commission with flexibility to look at the reasonableness of overall forecasts.

If the Commission continues with the BST approach, we consider that there needs to be appropriate flexibility in its application, as outlined below.

2.4.2 Selection of the base year under a BST approach

The standard approach regulators take when selecting a base year is to use the most recent year of actual opex available. As noted above, in DPP4 this may not represent a realistic expectation of the efficient and sustainable ongoing level of opex required to provide network services in the next regulatory period. It is our view that not much can be done regarding the choice of base year to overcome this problem given this is a problem that will exist even where the year with the most recent data is used. Instead, we consider the Commission would need to be flexible in its approach to step changes should it decide to apply the BST approach.

2.4.3 Accounting for capex/opex trade-offs under a BST approach

The Commission applied set criteria to assess step changes in both its DPP3 and EDB DPP4 decisions. It considered whether the step change was:

- significant
- adequately justified with reasonable evidence in the circumstances
- not captured in the other components of the DPP allowance
- a driver outside the control of a prudent and efficient supplier; and
- widely applicable.

In our view, these criteria are appropriate for GDB DPP4. They provide GDBs with sufficient guidance on the Commission’s approach, while allowing the Commission reasonable flexibility to make its decisions in the current uncertain operating context. We consider that the Commission should also have regard to Vector’s AMP in assessing its step changes.

2.4.4 Output growth factors

In DPP3 the Commission modelled the need for increased opex based on changes in network scale. It was modelled by scaling base opex in real terms for estimates of network length and Installation Control Point (ICP) annual growth in each year of DPP3.

To forecast how increases in network length affect opex, the Commission used historical trends of network length and ICP growth and the relationship between the two. The ICP growth and network length estimates were modified by an elasticity factor that models their non-linear relationship with opex.[3]

Growth in Vector's network is caused by new customer connections or increasing demand from existing connections. Vector's recent AMP notes that due to the forecast decline in customer connections and decline in demand it is not forecasting any system growth projects during the 10-year planning period.[4]

We consider the Commission's existing approach is no longer suitable given the forecast decline in customer numbers and volumes. The Commission's elasticity models of the relationship between network scale and opex are unlikely to produce accurate results in the context of falling customer numbers, a network that is no longer growing, and costs which are largely fixed. We consider a floor of 0% on the output growth factor would be a reasonable approach for DPP4 if the Commission continues with the BST approach.

2.4.5 Productivity growth

Under the Act, the Commission must set a rate of change for the GPBs based on the long-run rate of productivity improvement achieved by suppliers of the relevant goods or services in New Zealand or other comparable countries.

In DPP3, the Commission decided not to apply a productivity adjustment (i.e. 0%). This was based on an earlier finding that there was no evidence to indicate that the productivity of GPBs improved by more or less than the rest of the economy.[5]

We consider the Commission's approach in DPP3 remains appropriate for DPP4. The figure below shows multifactor productivity (MFP) in the utilities industry, which includes gas distribution, has continued to lag behind the goods and service industries. Since the late 1990's, MFP has declined in this sector, indicating there is no compelling reason to change from the Commission's approach in DPP3. Further, with the outlook for falling output and increasing opex, it will be difficult to achieve productivity growth. This doesn't reflect inefficiency for gas pipeline businesses, but rather is a consequence of an uncertain future network.

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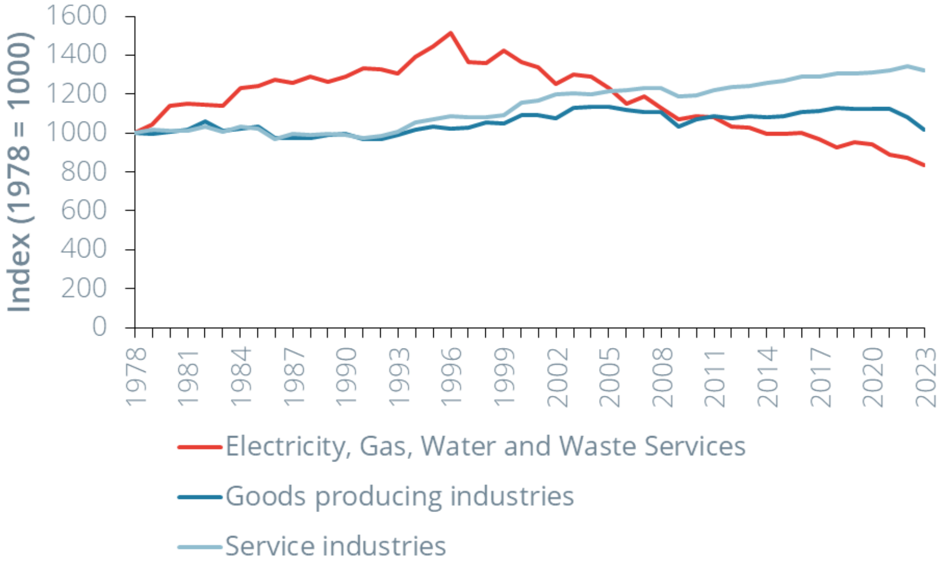
3 Commerce Commission, Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper Date of publication: 31 May 2022, p 139.

4 Vector, 2025—2035 Gas distribution asset management plan, p 71

5 Commerce Commission, Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper Date of publication: 31 May 2022, p 141.

Figure 1: Multifactor productivity in New Zealand (1978-2023)



Source: Stats NZ, https://www.stats.govt.nz/information-releases/productivity-statistics-1978-2023/

3 Managing demand and connection forecasting risk

This section considers whether the within-period risk of increasing or decreasing gas usage and connections to the gas network is best allocated to GDBs, to customers or to a combination of both.

The risk of variations to demand and connections during DPP4 is allocated through the form of control that is applied. Therefore, this discussion focuses on which form of control is more likely to promote the Part 4 objective, taking into account all of the advantages and disadvantages of the available approaches to the form of control.

The section first identifies the approach that the Commission has proposed for the form of control, and the reasons given for adopting that approach. To inform our consideration of which approach is best applied to Vector in the current circumstances, this section then considers the economic characteristics of the two main approaches to the form of control, the weighted average price cap (WAPC), and the revenue cap. This is followed by our views on what form of control is likely to be best suited to Vector's current circumstances.

3.1 Commission's position

The Commission's has stated a preference for retaining a WAPC for Vector and other GDBs in the 2023 IM Review and its recent Issues Paper for DPP4. We outline the key reasons for this view here.

3.1.1 2023 IM Review

In 2023 the Commission published its IM Review final decision on issues that relate to regulated suppliers' incentives to spend efficiently. This review considered the tools and mechanisms that affect incentives for efficient investment and spending in a context where climate change and the need to electrify to decarbonise the economy are impacting on demand and expenditure for regulated services. One of the key topics it addressed in this review was the form of control.

The Commission acknowledged that quantity forecasting could become more difficult in the short-to-medium term due to uncertainty regarding the uptake of emerging technologies.[6] Nevertheless, its decision was to maintain the WAPC for GDBs, the view being it better promotes s 52A(1)(a) and (b), including in the following ways:

- A WAPC provides suppliers with a stronger incentive to tailor expenditure to changes in demand, such that consumers that value gas supply can continue to benefit from it, which may not occur if a revenue cap was applied.[7]
- The stronger incentive for efficient expenditure under a WAPC arises because, "…*if the actual demand turns out to be lower than the forecast, under a WAPC, suppliers recover less money and*

[6] Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.467.

[7] Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.484.

therefore have a strong incentive to reprioritise expenditure to find efficiencies and make savings".[8]

- GDBs are better placed than consumers to manage the consequences of forecast error, being the difference between forecast and actual quantities supplied, rather than the actual change in demand.[9]
- GDBs can influence demand through connections and reconnections, acknowledging they cannot manage demand quantities from existing connections.[10]

The Commission directly responded to submissions suggesting that the incentives to grow demand under a WAPC are no longer relevant due to the transition to net zero emissions. Here, the Commission recognised that gas is expected to decline in the long term, but considered the heightened incentives to invest efficiently that are delivered under a WAPC in this environment make it superior to a revenue cap.[11]

Another comment of note in this report was that the Commission recognised that peak charging signals are less valuable in gas than electricity. This is relevant given, as will be discussed below, the form of control chosen has an effect on the incentives for setting efficient price structures.[12]

3.1.2 Issues Paper

The Commission's Issues Paper noted that WAPC had been determined in the IMs but raised the question of whether there could be any significant in-period demand variations in a disclosure year of DPP4 that are outside of the GDB's reasonable control that could not be managed with existing regulatory tools.

Attachment A of the Issues Paper provides further discussion on the issue of the form of control. Here, the Commission is focused mostly on the incentives to set accurate forecasts, noting that GDBs may have an increased incentive to set conservative forecasts. This is because if actual demand turns out to be higher than forecast over the period the GDBs could earn more revenue than is required to recover efficient costs, depending on the drivers of demand and the structure of tariffs.

Attachment A also discusses some alternative ways to manage within-period demand risk. For instance, it notes that there is no demand reopener available, but that GDBs are best placed to manage in-period demand risk through their expenditure and pricing decisions and so should bear this risk.[13] It also raises the alternative of a cap-and-collar tariff variation mechanism as a hybrid form of control. This form of control, which has recently been approved by the Australian Energy Regulator in Australia, would set a band where GDBs would be exposed to demand variations, but an adjustment would be made when demand falls outside that band. The

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8 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.461.

9 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.464.

10 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.482.

11 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.514.2

12 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.510.

13 Commerce Commission, 'Gas DPP4 reset 2026 Issues paper – Attachments A - E 26 June 2025', para A25.

Commission did not support this type of hybrid form of control because it would absolve the distributors of their volume risk and the benefits this derives.[14]

3.1.3 Approach for gas transmission

For gas transmission businesses, the Commerce Commission decided to apply revenue caps rather than a WAPC. When this was done in 2013 the key justification for a revenue cap was the difficulty in forecasting growth. Specifically, the Commission stated that:[15]

> *Because we are not able to forecast these values reasonably accurately, allowed revenues may be significantly higher or lower under a weighted average price cap than required by the business. By contrast, the application of a revenue cap means that each supplier's revenues will reflect costs that are relatively straightforward to predict.*

The Commission affirmed its decision to apply revenue caps to GTBs at both the 2016 and most recent IMs reviews. For example, it its 2016 IM review it again commented on forecast difficulty as a justification for adopting a revenue cap, stating:[16]

> *we consider that gas transmission demand is difficult to forecast and that transmission businesses have little ability to influence demand, and so keeping a revenue cap is in the long-term interests of consumers by ensuring suppliers are more likely to be incentivised to invest efficiently compared to alternatives (consistent with s 52A(1)(a) and (b)).*

3.2 Frontier Economics' views

In this section we first describe the incentives under a WAPC and a revenue cap to reveal what impact these incentives might have in an environment of falling demand for gas pipeline services. We then respond to some of the key justifications for a WAPC offered by the Commission. Finally, we provide our views on the options for the approach to the form of control for Vector given its current circumstances.

3.2.1 Incentives under a WAPC and revenue cap

The primary function of the form of control is to translate the total revenue allowance that has been determined in a regulatory review into a formula that sets a cap over the regulated business's revenue or prices until the total revenue allowance is next reviewed. Different forms of control create different incentives for network businesses. This is caused by the extent that revenues are linked to consumption, and potentially also the flexibility that is afforded to businesses to set individual prices.

When considering the economic characteristics of different forms of control, it is important to keep in mind that the incentive for a regulated business is to maximise its (risk adjusted) profits. As will be shown here, under different forms of control, profit maximisation is not necessarily achieved through increased sales. Indeed, depending on the form of control and how prices are set, increased sales can actually harm profits for regulated network businesses.

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[14] Commerce Commission, 'Gas DPP4 reset 2026 Issues paper – Attachments A - E 26 June 2025', para A40.

[15] Commerce Commission, *Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services*, 28 February 2013, Attachment F, para F9.

[16] Commerce Commission, *Input methodologies review draft decisions – Topic paper 1: Form of control and RAB indexation for GDBs, GPBs and Transpower*, 16 June 2016, paragraph 148.

Incentives and outcomes under a WAPC

Under a WAPC the extent to which prices reflect costs will determine the extent that profits vary with sales. For example, with an increase in sale profits will fall where the price is less than the marginal cost of supply at the time of consumption, but will increase where the price is greater than the marginal cost of supply at the time of consumption. Furthermore, prices below marginal cost might be expected to drive excessive consumption, and impose even greater costs on the business. Similarly, prices above marginal cost might be expected to discourage otherwise efficient consumption and so lead to reduced sales for the network business.

The implication of the interaction between profits and prices under a WAPC is that there is a natural dynamic to set prices to reflect the cost of supply. That is, when prices are set efficiently, an increase in cost brings an increase in revenue and vice versa. Two additional implications that are important are that:

- It cannot be assumed that more sales will mean more profit for a network business under a WAPC. Instead, where prices are set efficiently, if there are more sales a WAPC merely serves to protect the profit of the business, hence the incentive to set efficient prices.
- Where prices are set efficiently, the network business has an incentive to meet any efficient new demand, and not promote inefficient demand. This is because the objective of the business is to increase or protect profit, rather than to increase sales per se.

From the customer perspective, within the period, under a WAPC they have increased certainty about what prices they will face. While the network business can undertake tariff rebalancing to better align prices with costs, and so this can cause some changes in price, it is typical that constraints are placed on how much rebalancing can be done year-to-year.[17] However, the fact prices are fixed within the regulatory period can mean that large changes in prices are required between regulatory periods to account for changes that have occurred within the regulatory period.

Incentives and outcomes under a revenue cap

Unlike under a WAPC, under a revenue cap revenues are fixed over the regulatory period. Obviously, where actual sales differ from forecast sales it will still mean that the revenue received will be different to target revenue. Therefore, to preserve the revenue cap an adjustment to prices is needed to correct for the difference between target revenue and actual revenue earned in a year. To illustrate the point, if there was no variable charge and prices were entirely fixed (and there were no connections or disconnections), there would be no need for any change in prices to meet target revenue over the regulatory period. The key implication of a revenue cap form of control is that whether more or less gas is consumed, or whether there are more or less connections, there will be no impact on whether revenue earned over the regulatory period.[18]

Remembering that the primary focus for the business is to maximise profits, under a revenue cap a business will seek to minimise the extent to which increased demand leads to higher costs within the regulatory period. This is because when revenue is fixed, reducing costs is the mechanism for driving higher profits. Conversely, if increased demand imposes higher costs onto a business subject to a revenue cap profits will decline or be in deficit. These potential profit

[17] For example, a regulated business would have an incentive to rebalance tariffs towards faster growing services and customer types under a WAPC given these are expected to drive increased costs in the business.

[18] This is putting aside any revenue that might be earned as part of a connection fee for a new connection. Noting this revenue will typically be directly related to the costs caused by the new connection.

outcomes create an incentive for regulated businesses to set very high prices at peak times that drive network costs.

A key benefit of revenue caps is that they provide increased certainty about revenue recovery (if not profitability). Increased certainty over revenue recovery is particularly beneficial where non-demand related costs are expected to prevail compared to scenarios where costs are expected to vary more by the amount of gas sold. This revenue certainty is also beneficial when the regulated business has less control over the amount of gas demanded or the volume of customer connections or disconnections.

From a customer perspective, the need to ensure that the revenue cap is met means that prices can vary year to year so that this is achieved, such that there is much less within-period price certainty. However, this will depend also on the structure of prices. For instance, where prices are set using predominantly fixed prices customers will experience highly stably prices over the regulatory period irrespective of the amount of gas they use. The fact that prices change throughout the regulatory period to adjust for changes in demand can mean that prices between regulatory periods may be more stable under a revenue cap than is the case under a WAPC.

Implications of the incentives and outcomes under each form of control

Some of the implications that arise from the discussion above are:

- Where there is an expectation that demand will drive the costs of the business a WAPC is likely to be preferred given this can ensure that revenues increase as costs increase. Conversely, if costs are not primarily driven by demand a revenue cap should be preferred. This is because, otherwise, the business might be exposed to windfall gains or losses as demand varies from forecast.

  In particular, given the need for regulation to provide a reasonable expectation of earning at least a normal return on investment (i.e., FCM), where costs are not predominately driven by demand – such as expenditure for replacement assets and maintenance – FCM could be threatened under a WAPC if demand is falling or customers are disconnecting. This is because revenues can fall below the revenue required to meet efficient costs. While tariff structures can mitigate this effect under a WAPC, businesses remain exposed to disconnections. In this case, to preserve profits, a regulated business would have an incentive to inefficiently defer expenditure and so increase the riskiness of the system or degrade overall service performance. This would clearly be a worse outcome for customers that remain connected to the network.

- Where a business has the ability to influence demand outcomes it is preferable to adopt a WAPC. This is because the WAPC can deliver a profit incentive on the business to drive increased demand.

- Both forms of price control will deliver incentives to minimise expenditure, however, this is expected to be at least as strong under a revenue cap as a price cap, particularly with respect to demand driven expenditure, given revenues cannot increase so the only way to increase profit is to reduce costs.

- Under a revenue cap the business is not penalised for promoting peak reduction demand response, however, there is actually an incentive to promote excessive peak reduction demand response under this form of control. This is because it can minimise demand driven additional costs. Conversely, under a WAPC, the business should be motivated to encourage the right amount of demand response where prices reflect the costs of supply.

3.2.2 Response to the Commission's position

In this section we consider the views of the Commission given the circumstances faced by Vector and other GDBs in New Zealand with respect to the form of control.

Incentives for efficient expenditure

The Commission has maintained support for the WAPC for gas distributors, in large part due to a perception that with falling demand and reduced revenue there will be a stronger incentive for efficient investment. This perspective ignores two fundamental features of the forms of control discussed here:

- There is already a very strong incentive to minimise expenditure under a revenue cap. As identified above, regulated businesses are focused on profit, rather than revenue, and to maximise profit they will aim to minimise costs to the extent they can while achieving service performance obligations. This incentive for cost minimisation is preserved irrespective of the direction of demand.
- Falling demand implies cost recovery is less focused on demand driven costs. Instead, costs for GDBs in this environment are expected to be focused mostly on preserving service performance outcomes for existing customers. Indeed, Vector is not forecasting any system growth projects over the 10-year planning horizon.[19] Under a WAPC with falling demand, even with efficient tariff structures, GDBs risk not being able to profitably fund service performance expenditure.[20] This introduces the potential that they are not able to earn at least a normal return on investment, and so preserve FCM, unless they inefficiently defer reliability and service performance expenditure.

These perspectives mean that a key justification of the Commission for preferring a WAPC in a circumstance with falling demand is flawed. That is, in an environment with limited demand driven expenditure, reducing revenues under a WAPC will not promote more efficient expenditure, instead, to preserve profits, the incentive will be to inefficiently defer or avoid spending on asset replacement and service performance expenditure. This will ultimately be to the determinant of customers. Furthermore, given the strong profit motive to minimise expenditure under a revenue cap form of control, it is not necessary to retain a WAPC to maintain incentives for cost efficiency. To the extent that the Commission believes stronger incentives are needed this can be achieved through other means. For example, the incremental rolling incentive scheme increases the power of the incentive for businesses to seek out efficiency gains and ensures businesses retain an equal incentive to seek efficiency improvements in each year of a regulatory period.

Conversely, however, adopting a revenue cap with falling demand will deliver an assurance to GDB that they will be able to at least recover their efficient costs, where these costs are driven mostly by asset replacement and service performance expenditure. This is an outcome that is clearly consistent with s 52A(a) of the Commerce Act 1986.

Allocation of demand risk

The Commission also indicated it believes that GDBs are better able to bear, or manage, demand risk. This was further justification for persevering with a WAPC form of control.

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[19] Vector, '2025—2035 gas distribution asset management plan', p.71.

[20] This is because demand falls can also come from disconnections, which is expected to be a dominant source of demand reductions into the future.

Putting aside the prospect of actual asset stranding, it is important to be clear at the outset, that ultimately it is customers who bear demand risk over the long-term. That is, if demand is falling, prices will either rise year-to-year within the period (under a revenue cap) or between periods (under a price cap). Under either form of price control, if demand is falling remaining customers will ultimately be required to pay a higher price for gas pipeline services. Therefore, what is at debate here is only who bears within period demand risk.

It is our view that the fact that customers ultimately bear this demand risk is a fair balancing of interests between regulated businesses and consumers. The reason the investments were made in the first instance was for the benefit of customers based on their demand for the service. The agreement with customers is that these investments are made with an expectation those costs can be recovered over an extended period of time (i.e., FCM). For regulated assets, this is a period of time that is much longer than would occur in competitive markets, where long-term contracts may be used in a similar circumstance. Ultimately, this longer recovery period serves to reduce prices and, therefore, delivers benefits to customers.

Putting aside the fact that customers bear the long-term price risk associated with changes in demand, current circumstances suggest that GDBs have very limited means to influence demand. Expecting GDBs to be motivated to drive increased demand was premised on the expectation that they would be driven to encourage connection to a new pipeline running down a street. However, there are now significant external factors that make this an unrealistic prospect, with the more likely outcome that these external factors see more and more customers disconnect from the system for reasons outside the control of GDBs. These external factors (discussed further in Section 4.2.2) include:

- Government climate change policy striving for net zero emissions, which in-turn is encouraging customers to electrify
- Rising wholesale gas prices driven by a severe shortage of gas and electricity generation willing to pay high prices for gas during dry winter periods
- Reduced gas supply limiting long-term supply options for gas retailers, with evidence some retailers are declining new connections due to this concern; and
- Rising energy costs generally in New Zealand have been driving large commercial and industrial users out of the market entirely.

None of these factors driving reduced demand and disconnection are within the control of GDBs. Therefore, requiring GDBs to manage this within period risk only serves to reduce their ability to fund expenditure required to maintain service performance.

It is worth noting also that even under a revenue cap GDBs remain exposed to demand risk and so have an incentive to do what they can to preserve existing demand. To the extent that Vector and other GDBs can avoid or delay the 'death spiral' that comes with reduced connections and increasing prices, they will limit their exposure to stranding risk.

Forecasting accuracy

The Commission noted the conflicting incentives for forecasting accuracy under a WAPC, suggesting, however, there may be a bias for lower forecasts for demand.

In the first instance, we note that given current outcomes, it is not apparent that GDBs have been overly conservative in their forecasts of demand in order to drive higher prices under a WAPC. This is because, as shown by the Commission in Figures A2 and A3 of Appendix A of the Issues Paper, demand and new connections are both currently tracking below forecast.

It is our view that this outcome suggests that the form of control is not currently having a material impact on the accuracy of the forecasts. That is, the perceived incentive under a WAPC to forecast below expectation is not being borne out. Instead, it is just becoming increasingly difficult to forecast demand in an uncertain environment. For this reason, we consider that the incentives for forecasting accuracy should not be a determining factor for the choice over the form of price control. Furthermore, it is important to remember that the ability for GDBs to set forecasts is not unbounded. There is strong regulatory oversight on the forecasts such that there is a reasonable likelihood that they end up being unbiased.

We note further, that the difficulty with accurately forecasting demand was a key reason for the Commerce Commission to adopt a revenue cap for gas transmission businesses. It is not clear to us why the same logic would not now apply to gas distribution businesses given they now face considerable gas demand uncertainty.

3.2.3 Options

A WAPC is no longer appropriate

It is our view that a WAPC is no longer appropriate for GDBs in New Zealand for the following reasons:

- GDBs have very limited influence over future demand given this will be driven predominantly by government policy, environmental concerns, and the wholesale price of gas in an environment of substantially constrained supply.
- With falling demand, the GDBs costs will not be driven by demand driven expenditure, so the benefit of using a WAPC to align revenues with increases in demand driven costs is severely diminished, if not lost entirely.
- Even with declining demand it is necessary for GDBs to invest to maintain service quality and reliability. With declining demand and reduced revenue, under a WAPC, the ability to fund these investments and maintain profits will be severely challenged. Rather than encourage efficiency, as posited by the Commission, reducing revenue in this environment as demand falls is more likely to provide an incentive for inefficient deferrals and cost cutting to maintain profits and FCM.
- A WAPC does not shield customers from demand risk, it merely does so within the regulatory period. In the long run, customers bear demand risk. Furthermore, under a WAPC, the large price changes that can occur between regulatory periods may serve to encourage faster disconnection due to price shock than if prices change more gradually over time.

A revenue cap is preferred

Given a WAPC is no longer appropriate, it is our view that a revenue cap should be applied to GDBs, including Vector. A revenue cap maintains strong incentives for cost efficiency while also ensuring that the businesses have a reasonable expectation that they can fund the replacement and service performance projects that are required through the regulatory period.

Importantly, even under a revenue cap, Vector and other GDBs will retain an incentive to preserve demand where possible. This is because maintaining demand helps avoid or delay the ‘death spiral’ that could result from further disconnections and declining usage, thereby reducing the risk of asset stranding

A hybrid form of control can deliver within-period demand risk exposure to GDBs while also preserving FCM where demand declines materially

If the Commission is of the view that it is essential for GDBs to retain some specific within period revenue risk associated with demand outcomes, it is our view that the next best option is to adopt the type of hybrid control that has been adopted recently in Australia. Under this proposal, the business bears some of the demand risk when it is within a reasonable band. However, where it falls outside of this band, and so where it would have a material impact on revenue recovery, an adjustment is made to preserve revenues. This approach, therefore, has the combined benefit of exposing GDBs to demand risk while also ensuring there is sufficient certainty over revenue recovery that essential expenditure to maintain service performance and reliability can be undertaken. That is, it recognises that the impact on revenues outside of the band would be too severe for the regulated business and so, unless rectified, would have negative consequences for customers in terms of the incentives and capability to undertake welfare improving expenditure for the benefit of existing customers.

Importantly, it is our view that this option is not superior to adopting a revenue cap, and we only suggest it as being superior to continuing to adopt a WAPC form of price control in the current environment.

Reopeners

An additional option to manage demand risk that has previously been put to the Commerce Commission is to apply a demand reopener if actual demand turns out to be below or above the underlying forecast by a pre-specified margin, such as 10%.[21] The Commission rejected this option based on its view that GDBs are best placed to manage within-period demand risk and so should bear this risk. It also indicated it would not be in the long-term benefit of consumers to shift some downside risk to consumers while GBDs would benefit if they were to outperform the forecasts.[22]

It is our view that the reasons given by the Commission for rejecting reopeners are misguided. It is our view that reopeners would lead to better outcomes than the status quo given the inability for GDBs to efficiently manage and respond to within period demand risk.

In the first instance, it is an empirical question about whether GDBs would benefit if demand turned out higher than forecast noting, as identified above, an increase in demand under a WAPC does not necessarily imply an increase in profit. This will depend on what has caused the change in demand (i.e., usage versus connections and disconnections as well as whether the usage imposes additional costs), and also the structure of tariffs. Nevertheless, the reopener provision was proposed to apply symmetrically such that the expected losses or gains under the mechanism would also be symmetric with unbiased forecasts of demand.

More importantly, however, the evidence suggests that it is actually far more likely that demand will fall rather than increase, and the consequences of a fall in demand, where this causes reduced revenue, are asymmetric on GDBs, and by implication, for customers. This is because, as stated above, the fall in revenue will challenge the ability for GDBs to fund necessary investments efficiently. To the extent this occurs, this would lead to worse outcomes for customers.

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21 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.505.

22 Commerce Commission, 'Financing and incentivising efficient expenditure during the energy transition topic paper Part 4 Input Methodologies Review 2023 – Final decision', para 3.507.

4 Managing asset stranding risk

This section considers the management of asset stranding risk for GDBs, specifically how this risk can be managed through accelerated depreciation.

This discussion focuses on whether the approach to accelerated depreciation adopted by the Commission for DPP3 remains appropriate, or whether changes to the gas market in New Zealand since that decision suggest amendments to the approach are warranted.

The section first identifies the approach that the Commission adopted for DPP3 and the initial view presented in the Issues Paper. This section that provides a short review of approaches to accelerated depreciation in other jurisdictions, and a short review of the current state of the gas market in New Zealand and outlook for the market. Finally, we provide our views on amendments to the approach to accelerated depreciation.

4.1 The Commission's position

4.1.1 DPP3 reset

For the DPP3 reset, the Commission developed long-term scenario modelling to inform its assessment of a reasonable provision for asset life shortening. The modelling was based on two plausible scenarios for the scaling down and eventual closure of pipeline networks, one in which the closure of the pipeline networks occurs in 2050 (given a one-third weighting), and a second in which the closure of the pipeline networks occurs in 2060 (given a two-thirds weighting).

The Commission observed that the resulting shortening of regulatory asset lives was to mitigate stranding risk while seeking to avoid undue pricing burden on consumers of bringing forward revenue recovery. The Commission recognises that the adjustments mitigated stranding risk only based on the two scenarios that were modelled. GDBs remain exposed to stranding risk due to gas demand dropping more quickly than assumed or due to an earlier enforced phase out by Government; the Commission considers that these risks should encourage GDBs to make prudent investments and to take other mitigating actions. Specifically, the Commission considered that:

- exposure to some residual risk should encourage GDBs to make prudent investments in growth and new connections; and
- GDBs could take action to mitigate stranding risk by increasing capital contributions and by augmenting parts of the network to carry renewable gases.

The Commission also considered that shortening asset lives would result in more cost-reflective pipeline charges, on average.

4.1.2 Issues Paper

In its Issues Paper the Commission noted that it expected that its decision for DPP4 would be informed by updates to the scenario modelling undertaken for DPP3. While the Commission expects that the two scenarios used for DPP3 would be a reasonable starting point, the Commission also recognises that the modelling should be updated to consider evidence indicating that those scenarios – including the assumptions about aggregate willingness-to-pay over time – should be updated to reflect more recent information. However, the Commission noted that it is important to bear in mind that its objective is:[23]

> *not to determine the most likely future end-state for gas pipeline businesses. Rather, it is to assess regulatory actions that can be taken at this DPP reset to best promote the long-term benefit of consumers under a range of plausible outcomes and conditions of high uncertainty.*

4.2 Frontier Economics' view

4.2.1 Jurisdictional review

Reviewing regulatory decisions for gas pipelines that have occurred in other jurisdictions over the period since the Commission's DPP3 decision reveals that there has been a general trend towards regulators taking increased action on accelerated depreciation in the time since the DPP3 decision, reflecting recognition that stranding risks for gas pipeline businesses have been increasing.

It is also clear from these decisions that the regulatory decisions on accelerated depreciation are very context-specific. In markets in which the future for the gas sector was seen as more positive, such as Western Australia and New South Wales, a lower allowance for accelerated depreciation was made. In markets in which the future for the gas sector was seen as less positive, such as Victoria and the Australian Capital Territory, a higher allowance for accelerated depreciation was made.

Western Australia – the Dampier to Bunbury Natural Gas Pipeline

The Economic Regulation Authority (ERA) in Western Australia is currently reviewing regulated tariffs for the Dampier to Bunbury Natural Gas Pipeline (DBNGP). It released its draft decision for the period commencing 1 January 2026 to 31 December 2030 (the period referred to as AA6) on 7 July 2025.[24]

For the previous regulatory period (AA5), commencing on 1 January 2021, the ERA accepted the proposal to accelerate depreciation for the DBNGP based on modelling undertaken at the time that suggested natural gas might be uncompetitive post 2060. The ERA's final proposal was to cap the economic life of assets at 2063 (resulting in accelerated depreciation for those assets that had a technical life that extended beyond 2063).

For the forthcoming regulatory period (AA6), the ERA's draft decision is to retain the economic life cap of 2063. This was consistent with the pricing proposal of the owners of the DBNGP and reflected their assessment of future demand conditions for the pipeline. The owners of the DBNGP, and their consultants, undertook granular modelling of demand for its major shipper segments. Being a gas transmission pipeline, the owners of the DBNGP identified its major shipper segments as industrial customers (including alumina refining, chemicals and gas processing) and gas generation. The owners of the DBNGP forecast gas demand under three scenarios, each of which had significant gas demand on the pipeline extending beyond 2063.

The ERA's draft decision to maintain the existing approach to accelerated depreciation for the DBNGP (despite recognising significant changes since the AA5 decision, including the establishment of new emissions targets) reflects the specific circumstances of the gas market in Western Australia. The gas market in Western Australia has abundant reserves of natural gas, a

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23 Commerce Commission, Gas DPP4 reset 2026, Issues Paper, 26 June 2025, page 34.

24 Economic Regulation Authority, Draft decision on revisions to the access arrangement for the Dampier to Bunbury Natural Gas Pipeline (2026 to 2030), 7 July 2025.

domestic gas reservation policy that ensures natural gas is available to the domestic market, and significant gas demand from industrial customers and gas generators that have limited options for electrification.

Western Australia – Goldfields Gas Pipeline

The ERA reviewed regulated tariffs for the Goldfields Gas Pipeline (GGP) in 2024, for the period 1 January 2025 to 31 December 2029 (the period referred to as AA5).

In its final decision the ERA agreed to cap the economic life of assets at 2065 (resulting in accelerated depreciation for those assets that had a technical life that extended beyond 2063). The ERA noted that since the time of its decision for AA4 (in 2019) technological and policy developments had resulted in increased uncertainty around the future for natural gas use. These changes included government emissions policies, improvements in electrical equipment and other technologies that can be used to substitute for natural gas and changes in customer preferences. The decision to cap asset lives at 2065 in particular was based on the similarity between the DBNGP and GGP. In particular, the GGP supplies gas to mainly mining customers, some of which have limited options to completely electrify their operations, and the Western Australian gas market has ample natural gas available to the domestic market.

Western Australia – the Mid-West and South-West Gas Distribution Systems

The ERA reviewed regulated tariffs for the Mid-West and South-West Gas Distribution Systems (MWSW GDS) in 2024, for the period 1 January 2025 to 31 December 2029 (the period referred to as AA6).

In its final decision the ERA allowed an amount for accelerated depreciation for the MWSW GDS. The approach proposed by the operator of the MWSW GDS did not involve setting a specific economic life for the network, but instead calculating a dollar amount for accelerated depreciation. While not agreeing with the proposed dollar amount, the ERA did accept the general approach of allowing a dollar amount for accelerated depreciation.

The context for the ERA's decisions was its recognition that the outlook for the gas sector had changed since the time of its decision for AA5 (in 2019). The broad reasons where the same as for the GGP: government emissions policies, improvements in electrical equipment and other technologies that can be used to substitute for natural gas and changes in customer preferences.

Nevertheless, the impact of these changes on the outlook for the MWSW GDS was unclear. At the time of the ERA's decision, demand and customer numbers for the MWSW GDS were growing, and continued growth was forecast for the period of AA6. The ERA recognised that long-term demand was uncertain, but the scenarios presented to the ERA by the operator of the network were generally optimistic. Of the four scenarios presented, one had demand continuing to increase, one had demand plateauing at around 2025 levels until the 2070s, one had demand plateauing at around 2025 levels until around 2050 before declining to around half those levels by 2070, and one had demand declining to very low levels by 2055.

New South Wales – Jemena Gas Network

The Australian Energy Regulator (AER) reviewed regulated tariffs for the Jemena Gas Network (JGN) during 2024 and 2025, for the period 1 July 2025 to 30 June 2030.

In the previous regulatory period the AER had not made any allowance for accelerated depreciation.

In its final decision for the 1 July 2025 to 30 June 2030 regulatory period the AER allowed an amount for accelerated depreciation for JGN. The AER explained that its approach for JGN in NSW reflected an expectation that the economic lives of JGNs pipeline assets are lower as a result of demand uncertainty. Its view on demand uncertainty had regard to the policy settings that applied in NSW at the time. Unlike in Victoria and the ACT, in NSW there was no statewide ban on new gas connections and no gas substitution roadmap. Given the relatively better outlook for gas in NSW, the amount of accelerated depreciation was relatively lower.

The approach adopted by the AER involved a combination of shortening the asset lives of pipeline assets as well as an additional amount of accelerate depreciation to ensure a more meaningful start to accelerated depreciation.

With respect to asset lives, the AER adopted a shorter asset life for both medium pressure (MP) pipelines and high pressure (HP) pipelines. The AER considered that MP pipelines face a greater risk of stranding because they largely supply residential and commercial customers that are more likely to transition away from gas. The AER adopted a 30 year asset life for these assets (implying full depreciation by 2055). The AER considered that HP pipelines face a lower risk of stranding because they largely supply industrial customers that are less likely to transition away from gas. The AER adopted a 50 year asset life for these assets (implying full depreciation by 2075). However, the AER also took additional action on accelerated depreciation.

With respect to its additional action on accelerated depreciation, the AER increased the allowance for accelerated deprecation from $45million for MP pipelines and $32million for HP pipelines (due to shorter asset lives) to a total of $115million. This amount was calculated to deliver an overall outcome for accelerated depreciation that was consistent with a 0.5% real per annum price increase. This additional amount of accelerated depreciation was applied to MP assets to reflect the greater stranding risk for these assets. This implied the amount of accelerated deprecation for MP pipelines increased from $45million to $83million. While the AER does not report the equivalent asset live that would deliver this result, it is clearly materially shorter than 30 years to 2055.

The AER emphasises at several points in its decision for JGN that it considers a measured start to accelerated depreciation provides the right incentive, indicating that the AER has in mind increased action on accelerated depreciation in future decisions.

Victoria – AusNet, Multinet Gas and Australian Gas Networks

The AER reviewed regulated tariffs for the Victorian distribution networks – AusNet, Multinet Gas and Australian Gas Networks during 2022 and 2023, for the period 1 July 2023 to 30 June 2028.

In the previous regulatory period the AER had not made any allowance for accelerated depreciation for any of the Victorian networks.

In its final decision for the 1 July 2023 to 30 June 2028 regulatory period the AER allowed an amount for accelerated depreciation for the Victorian networks. This was a response to the Victorian Government's *Gas Substitution Roadmap* (which the AER noted implied a limited role for natural gas beyond 2050) and gas demand forecasts from the Australian Energy Market Operator (AEMO) which forecast material declines in gas use over the 20 years to the early 2040s.

The approach that the AER adopted for each network was to make an allowance for accelerated that was consistent with a 1.5% real per annum price increase for each network.

ACT – Evoenergy

The AER reviewed regulated tariffs for Evoenergy during 2020 and 2021, for the period 1 July 2021 to 30 June 2026.

In the previous regulatory period the AER had not made any allowance for accelerated depreciation for Evoenergy.

In its final decision for the 1 July 2021 to 30 June 2026 regulatory period the AER allowed an amount for accelerated depreciation for Evoenergy. This was a response to the ACT Government's policies to move away from gas use, even though the AER noted that there are still uncertainties regarding the path the ACT Government would choose.

With respect to asset lives, the AER adopted a shorter asset life for both new medium pressure (MP) pipelines and new high pressure (HP) pipelines. The AER adopted a 30 year asset life for new MP pipeline assets (implying full depreciation by 2051). The AER adopted a 50 year asset life for now HP assets (implying full depreciation by 2071).

Evoenergy has submitted its pricing proposal for the forthcoming regulatory period – commencing on 1 July 2026. As part of this pricing proposal Evoenergy is proposing to set the remaining asset lives to end in 2045 – consistent with the ACT Government's legislated emissions reduction targets and policy direction to transition away from gas by 2045 – and to reprofile the depreciation amount over time.

United Kingdom

Ofgem is currently in the process of reviewing regulated tariffs for gas distribution businesses in the UK for the period from 1 April 2026 to 31 March 2031 (the price control period known as RIIO-3).

In previous regulatory control periods, Ofgem had set that asset lives for all capex from 2002 onwards, for all gas distribution and gas transmission businesses, at 45 years, with front-loaded depreciation.

For RIIO-3, Ofgem's draft decision is to maintain the existing 45 year asset life for all existing assets, but to set a new policy for new capital additions that sets assets lives to match the government net zero target date and that front-ends depreciation using a sum-of-digits approach which front-loads the depreciation profile.

Ofgem noted that this decision builds on the approach that it has made to front-load gas asset depreciation in previous regulatory periods.

Ofgem noted that this decision aligns with the UK Government's net zero target date of 2050. Ofgem also noted that other European regulators are making similar decisions, with Austria shortening depreciation periods from 30 to 20 years for new gas investments, the Netherlands accelerating depreciation by a factor of 1.2 and Germany providing gas network businesses the flexibility to depreciate their assets by either 2045 of earlier to meet regional or municipal decarbonisation targets.

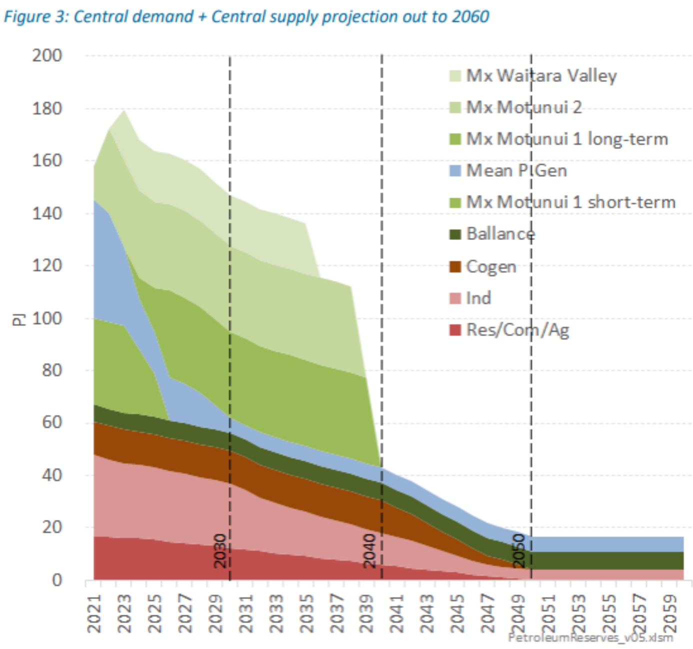
4.2.2 Current and future state of the gas sector in New Zealand

At the time of DPP3, it was accepted that there was a reasonable prospect the economic life of gas pipelines could be shorter than their physical life, and that forecasting future pipeline demand would be more challenging. Since that time, the situation for the gas sector in New Zealand has become even more volatile and precarious.

Until recently, the main driver of declining demand for gas has been the desire to reduce emissions in the economy. The significant change since DPP3 is that there are now severe constraints on gas supply. This fall in gas supply is happening far more rapidly than was previously forecast and is expected to have profound impacts on the use of gas.[25] Given there was already momentum for customers to use less gas, disconnect and electrify, the effect of this supply challenge can be expected to increase the risk of a substantial decline in demand for gas pipeline services.

In 2022, around the time of DPP3, gas supply and demand forecasts prepared for the Gas Industry Company (GIC) predicted there would be sufficient gas to meet user's needs for the very long term, and at least out until 2040.[26]

Figure 2: Central demand + Central supply projection out to 2060.



Source: Concept Consulting, 'Gas supply and demand projections', 24 March 2022, p.3.

Transpower, who prepare forecasts to ensure sufficient fuel availability for electricity generation, identified in its 2022 planning report that there were enough gas reserves and contingent resources for at least the next 10 years, stating:[27]

> *Our assessment suggests that there are enough gas reserves and contingent resources from existing gas fields to ensure on-going gas supply security for the 10-year assessment horizon.*

Since 2022, gas producers have been unable to find the gas resources they expected to find with high profile drilling projects coming up empty-handed.[28] Such expensive failures only serve to discourage further drilling and exploration activity. Furthermore, the ban on offshore oil and gas exploration has seen tier 1 producers exit the New Zealand market; meaning that expertise in finding gas has also left the market making the prospect of locating new reserves more challenging.

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25 Gas supply reducing faster and sooner than previously forecast | Ministry of Business, Innovation & Employment

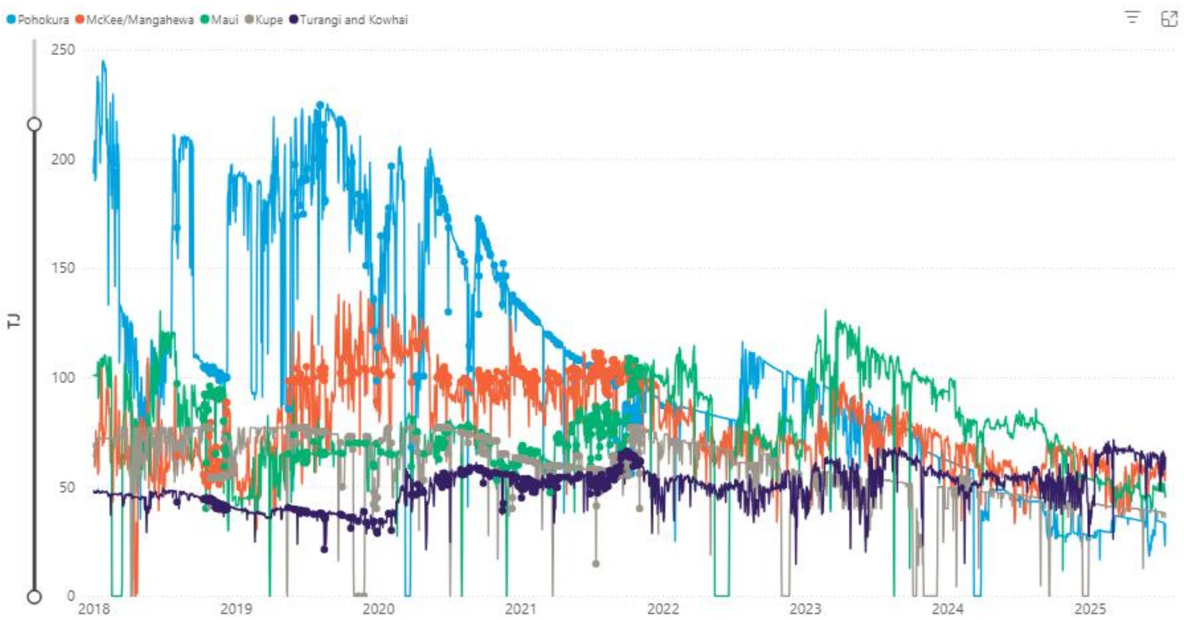
26 Concept Consulting, 'Gas supply and demand projections', 24 March 2022, p.2.

27 Transpower, 'Appendices for Security of Supply Assessment 2022, System Operator, Version: 2.0' 30 June 2022, p.2

28 See: https://www.rnz.co.nz/news/business/517508/attempts-to-get-more-gas-from-kupe-field-fail

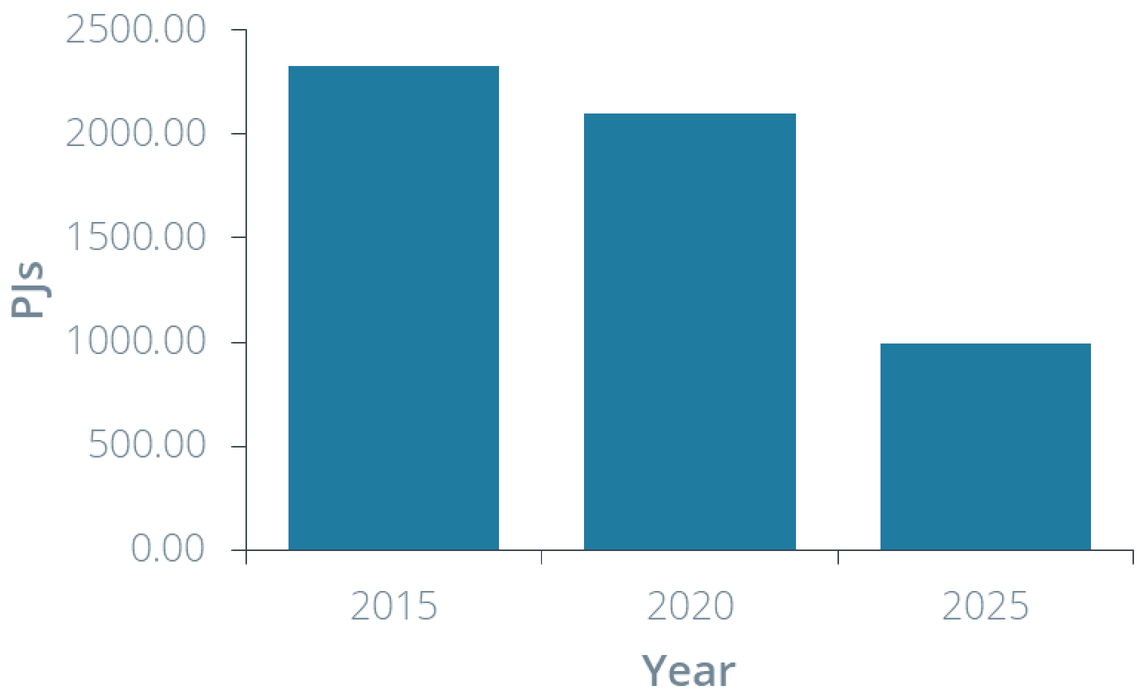
The result of the failure to find the amount of gas that was expected means that gas production and reserves have fallen well below historical levels, and levels that were forecast only a few short years ago. As show in in Figure 3 and Figure 4 both production and gas reserves have fallen substantially in recent years.

Figure 3: Daily gas production by major fields



Source: https://www.gasindustry.co.nz/data/gas-production-and-consumption

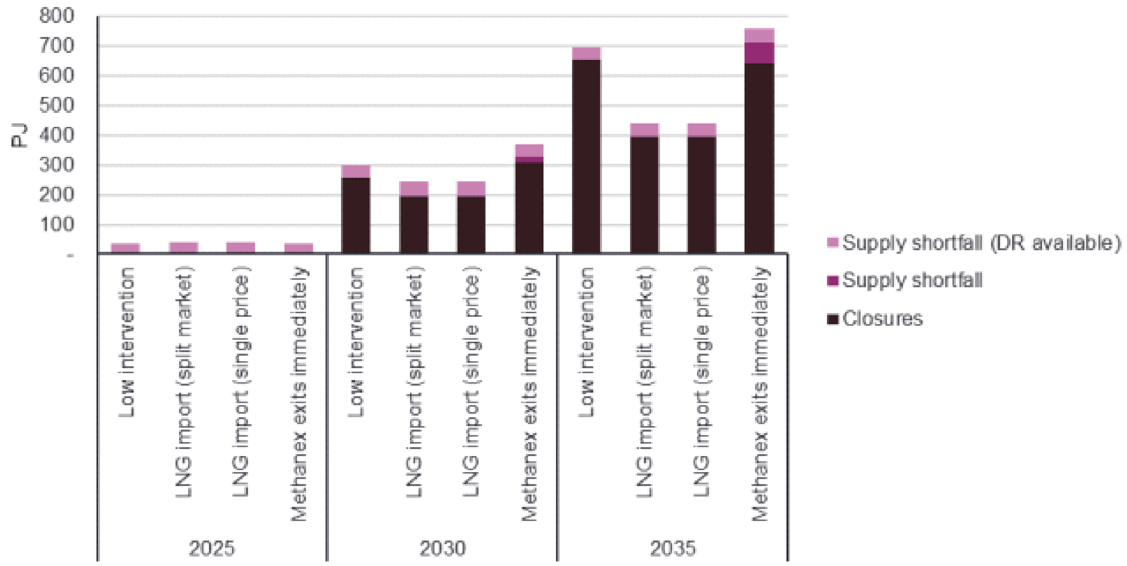
Figure 4: Gas and LPG combined reserves in New Zealand



Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/petroleum-reserves-data

Based on this change in circumstances, the most recent supply and demand forecast undertaken for the GIC forecasts anticipate that there is insufficient supply to meet requirements even in 2025 without demand response. It further predicts that gas price and supply constraints will drive supply shortfalls and industrial and commercial closures by 2030. This is shown in Figure 5 below. While much of the closure may come from Methanex leaving New Zealand, and this would serve to free up some supply, it also removes the largest buyer of gas in New Zealand. Losing the largest buyer of gas will discourage further investment in drilling and exploration as it will be far more challenging to find someone to underwrite that investment.

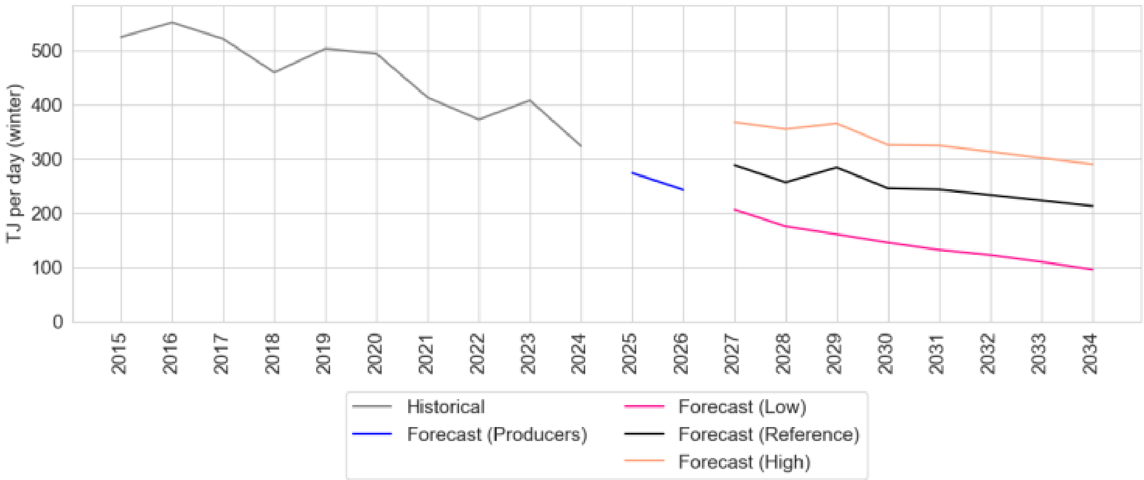
Figure 5: Cumulative amount of unsupplied natural gas demand from now until 2025, 2030 and 2035



Source: EY, 'Gas Supply and Demand Study 2024, Gas Industry Co.', p.11.

In addition, while in 2022 Transpower was forecasting security of gas supply over a 10-year period, in its most recent forecasts it is now forecasting falls in gas production over the next 10 years (Figure 6).

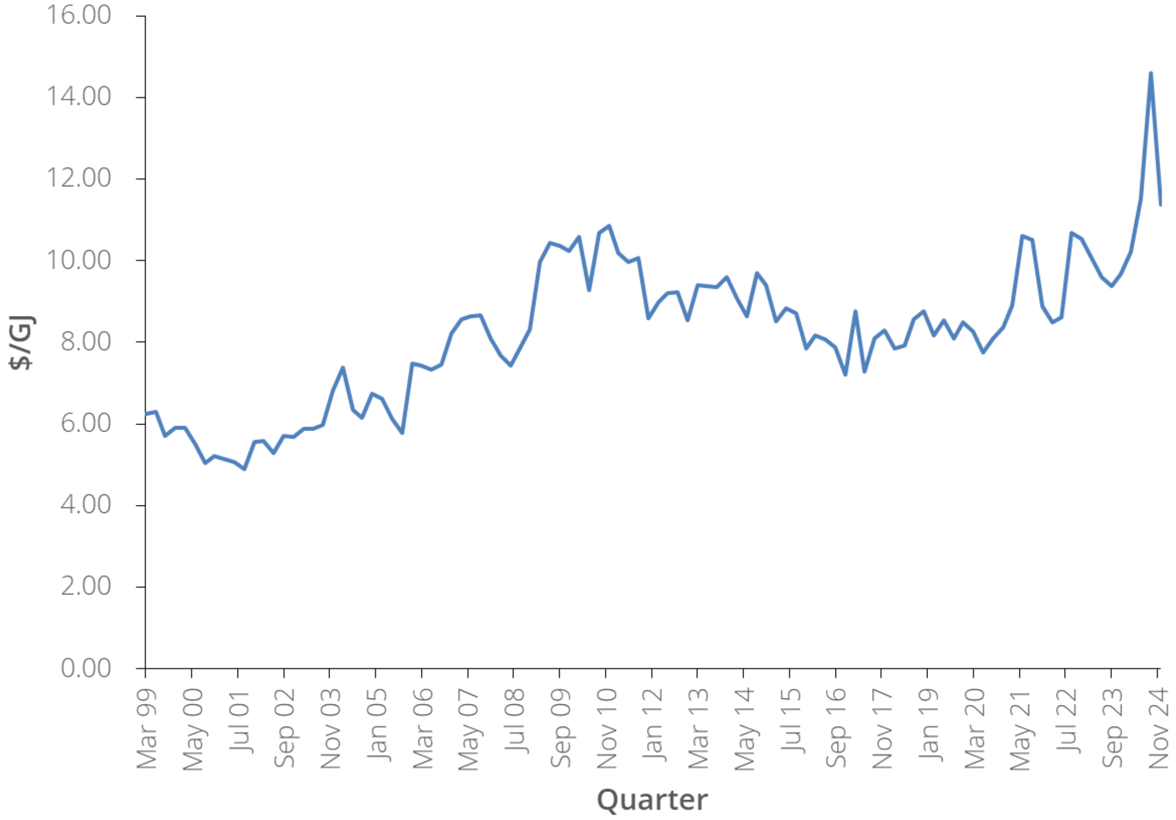
Figure 6: Gas production forecasts



Source: Transpower, 'Appendices for Security of Supply Assessment 2025 System Operator Version: 2.0 Date: 30 June 2025, p.24

The key impact of these declines in production and reserves is to increase wholesale gas prices, and so the cost of delivered gas for consumers. This is particularly the case when gas is required for electricity generation during a dry sequence in New Zealand where there is less output from the hydro generators. This is evident in Figure 7 below which shows the impact on wholesale gas prices during a dry sequence in 2024.

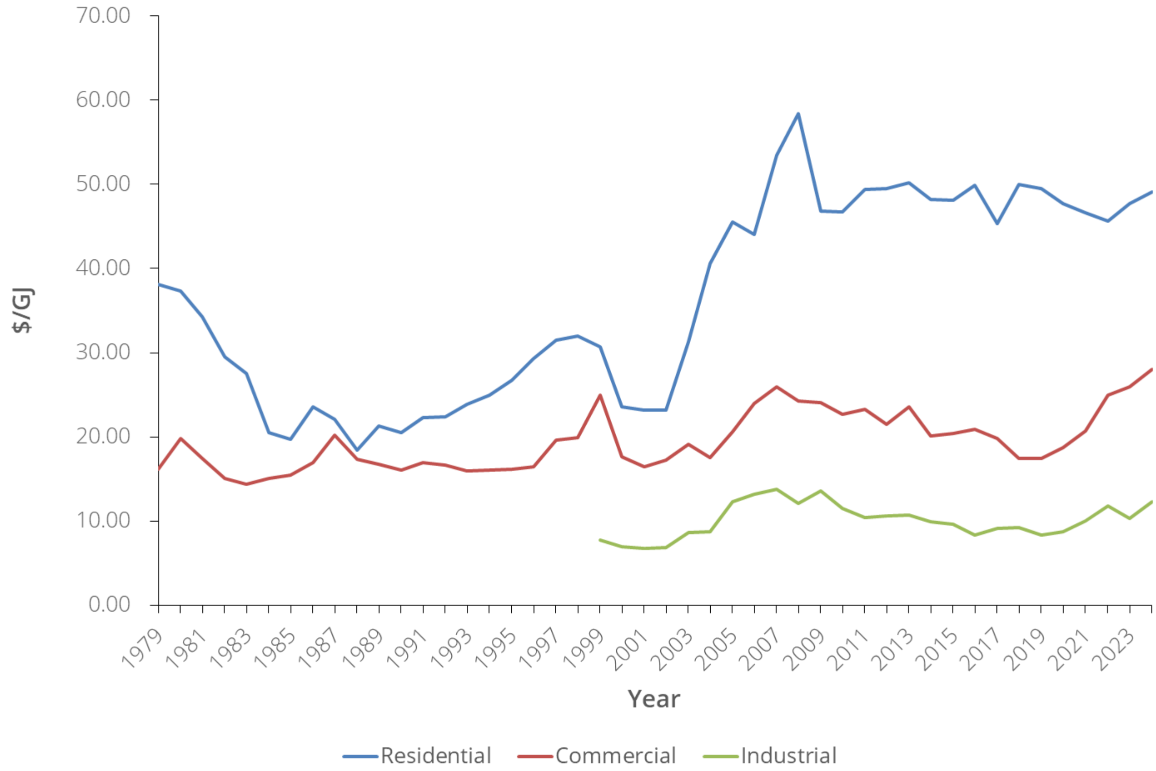
Figure 7: Quarterly wholesale gas prices



Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices

Ultimately, higher wholesale gas prices must feed through into consumer prices, albeit with a lag. Recent data shows annual residential, commercial and industrial gas prices have been rising compared to recent years.

Figure 8: Real annual residential, commercial and industrial gas prices



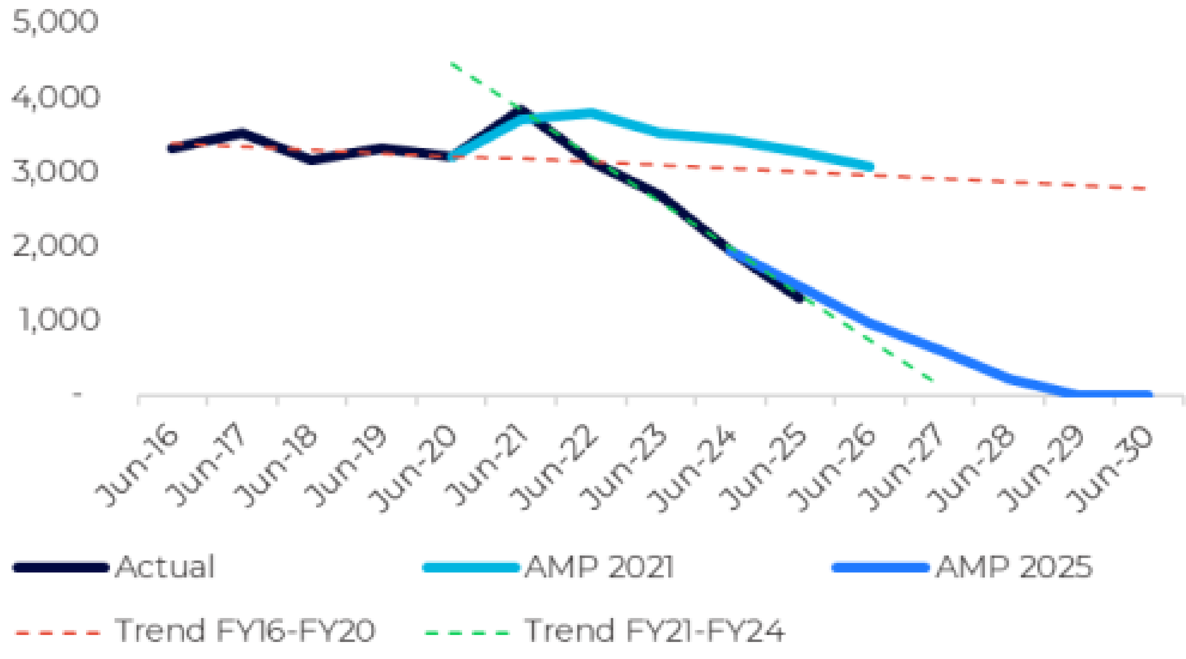
Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices

Should the wholesale price of gas continue to increase over time – which is a reasonable prospect without material additional gas supply being found – electrification and disconnection becomes increasingly attractive. This is particularly the case for residential customers and some commercial customers where the cost of switching to electricity is much lower than for certain industrial customers. Forecasts prepared for the GIC suggest that over the short term, under certain assumptions, residential demand for gas for space heating will reduce by up to 60% over the short term, and up to 95% over the longer term.[29]

Consistent with the forecasts prepared for the GIC, Vector is also now forecasting the number of new gas connections to decline at an accelerated rate, with no new connections from 2029. Conversely, disconnections are forecast to continue to increase over time (Figure 9).

[29] EY, 'Gas Supply and Demand Study 2024, Gas Industry Co.', p.55.

Figure 9: Gross connections - Vector



Source: Vector, Gas DPP4: Scenario Modelling Workshop, 15 July 2025

4.2.3 Our views

Our review of current and forecast conditions for the gas market in New Zealand suggest to us that there is a plausible scenario in which gas networks are decommissioned earlier than 2050. Among other things, this is due to the risk of near term shortages of gas supply, the uncertainty about sources of new gas supply in the long-term, the potential for increasing wholesale gas prices, and the impact that these have on decisions by customers and by policy makers about the continued use of gas.

The earliest date of decommissioning considered by the Commission in assessing accelerated depreciation for DPP3 was 2050. Given the worsening outlook for the gas market in New Zealand suggests that there is a plausible case for decommissioning of the gas networks before 2050, our view is that the Commission should consider a new scenario with earlier decommissioning of the gas network for DDP4. Given that the existing scenarios from DPP3, which see the gas networks decommissioned in 2050 and 2060 also remain plausible, our view is that the Commission should consider an *additional* scenario for DPP4, with decommissioning of the gas networks occurring by 2045, and that each of the three resulting scenarios should be given equal weight.

We think that this modification of the Commission's approach for DPP4 would be consistent with the broad approach to accelerated depreciation that can be observed in other jurisdictions. In particular, the extent of action of accelerated depreciation varies depending on the prospects for the gas sector in that jurisdiction. Given that the prospects for the gas sector in New Zealand seem more challenged that in many other jurisdictions, it is appropriate for New Zealand to consider stronger action on accelerated depreciation. Also, where new information becomes available, approaches to accelerated depreciation can change from one regulatory period to the next.

We have undertaken an indicative assessment of the impact on the Commission's accelerated depreciation modelling for DPP3 of an additional scenario with network decommissioning in

2045 and an equal weighting for all three resulting scenarios. The results are presented Table 1. This indicative assessment has been made using the Commission's DPP3 model, with no updates to that model. As a result, they are indicative only of the results that would be achieved for DPP4 with an updated model. Nevertheless, the effect of this indicative assessment shows that the adjustment factor is lowered, both as a result of the lower adjustment factor for the scenario with a 2045 wind down and because of the re-weighting to give equal weight to each of the three scenarios.

Table 1: **Adjustment factors**

	2045 wind down	2050 wind down	2060 wind down	Weighted average
DPP3	NA	0.60	0.70	0.66
DPP4	0.56	0.60	0.70	0.62

Source: Commerce Commission, Frontier Economics analysis

Reducing the adjustment factor has the effect of increasing the extent to which depreciation is accelerated. The result is that customers today make a greater contribution to depreciation of Vector's assets, and customers in the future will make a lesser contribution to depreciation. There is the potential that this will result in depreciation being accelerated more than is required to manage asset stranding; Vector's asset may have a longer remaining life than expected. However, we consider that the reducing the adjustment factor is justified at this stage precisely because circumstances in the New Zealand gas market suggest that the risk of earlier asset stranding is increasing and accelerating depreciation further is therefore important for promoting FCM. We note also that the modelling we have done applies the approach adopted by the Commission, which assumes the network continues until the last customers depart. We consider, however, it is more likely that the network will cease to operate when it is no longer viable. For instance, when Vector can no longer recover its avoidable costs of operation.

Furthermore, stranded asset risk is an aspect where there are asymmetric consequences from a failure to act sufficiently early. That is, if early action is not taken there will simply become a point where it is no longer possible to recover all the capital invested in the network. Therefore, it is prudent for there to be a bias towards earlier recovery, noting adjustments to extend asset lives can be made at a later date should new information reveal a longer asset life is more likely. The primary constraint on how much recovery is advanced is customer willingness-to-pay. That is, if prices were to rise too high this may exacerbate the stranding risk. Some important factors to bear in mind in this context however are:

- It is better to bring forward cost recovery while more customers remain connected to the network given this reduces the cost burden on individual customers
- While advancing prices now should lead to a more stable price path over time by minimising the extent that prices need to rise in later years when demand falls further
- At current rates, accelerated depreciation is a relatively low contributor to price increases; and
- There is no evidence that customer willingness-to-pay has, on average, been exceeded yet, recognising that, for residential customers at least, prices are still below peaks that occurred in 2007 (see Figure 8).

We also note that increasing the contribution of current customers to depreciation may result in a more equitable inter-generational allocation of capital costs. Regulatory depreciation represents the return of capital costs, to the asset owner, from customers. These capital costs are primarily driven by the number of connections and the amount of demand on the network. Two equivalent customers connecting to the gas network at the same time in a similar location would be expected to have a similar impact on the capital costs of the pipeline network. But, with capital costs recovered over time through regulatory depreciation, a customer that leaves the network earlier makes a smaller contribution to recovery of these capital costs than a customer that remains with the network, despite causing equivalent capital costs for the network. Accelerating depreciation can reduce this effect, and result in a more equal contribution to capital costs from customers, regardless of when they leave the network.

5 Treatment of decommissioning costs

5.1 Introduction

The retirement of gas pipelines will result in gas businesses incurring costs to decommission and remediate the remaining assets. As there will be no customers connected to the network at that point to fund these activities, it is prudent to provide for these costs while the network is still in use and customers are available to contribute. The purpose of this section is, therefore, to consider the appropriate approach to recovering decommissioning and remediation costs. The section provides a review of consideration of gas pipeline decommissioning costs in Australia and Great Britain, summarises the initial views put forward by the Commission and then provides our views on the principles relevant to decommissioning costs, including a mechanism to provide for recovery of decommissioning cost.

5.2 Decommissioning costs in other jurisdictions

5.2.1 Australia

The Australian Energy Regulator (AER) has not yet made a decision on the recovery of decommissioning costs for regulated gas networks in Australia. While the AER has allowed for the application of accelerated depreciation to mitigate stranding risks for gas network assets in its recent decisions,[30] in line with the National Gas Rules,[31] it has not explicitly addressed the recovery of full network decommissioning costs.

The lack of direct guidance from the AER on this issue is partly due to gas networks not having previously proposed allowances for such costs, and the NGR itself lacking explicit provisions for the recovery of decommissioning costs.

However, the AER has in its recent decision for Jemena Gas Networks (JGN), allowed for the recovery of abolishment costs, which pertain to the removal of individual gas network connections. This is a key distinction, as the AER differentiates these from "decommissioning" costs, which refer to the complete shutdown and safe removal of an entire gas network.[32]

For JGN, the AER has decided to move towards a partial socialisation of abolishment costs. This implies that a customer-paid abolishment tariff covers a portion of this cost, with the remaining costs socialised among all remaining customers via the opex allowance. This recent decision indicates the AER's evolving stance on how certain gas network-related costs will be managed and recovered.

While the AER has not made any decisions regarding regulatory allowances for decommissioning costs for regulated gas networks in Australia, it has acknowledged that decommissioning costs as a recoverable expense for commercial gas pipelines. This recognition is evident in the AER's

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30 Victoria, ACT, AusNet (2023-28) decisions

31 NGR 89 allows for the adjustment of depreciation schedules to reflect changes in the expected economic life of assets.

32 https://www.aer.gov.au/system/files/2025-01/JGN%20-%20Houston%20Kemp%20-%20RP%20-%20Att%203.1%20-%20Smoothing%20cost%20recovery%20when%20gas%20demand%20is%20declining%20-%2020250110%20-%20Public.pdf (p45, p48)

updated guidelines on information disclosures,[33] which are published and maintained under Part 10 of the NGR. These guidelines apply to service providers of both "scheme" and "non-scheme" pipelines, aiming to enhance transparency and influence the setting of pipeline tariffs.

Initially, the AER's consultation paper on these disclosure guidelines highlighted the considerable uncertainty surrounding the scope, costs and timing of decommissioning, a point with which the industry largely concurred. However, the Australian Pipeline and Gas Association (APGA) argued that decommissioning costs are an unavoidable component of an asset's lifecycle.[34] APGA argued that excluding these costs from recovered capital would contradict the NGR principles for non-scheme cost recovery, in particular, Rule 113Z 4(a) which stipulates that prices for access to non-scheme pipeline services should reflect the full cost of providing that service.

As a result, the AER revised its guidelines to require networks to provide information on "residual values included in the capital base (e.g., decommissioning costs)." This requirement extends to providing the rationale for estimates related to decommissioning, including details on rehabilitation timing and scope. Given that the AER has adopted this stance for commercial pipelines, this suggests a potential precedent for future considerations regarding the recovery of decommissioning costs for the broader gas distribution network.

5.2.2 Great Britain

Ofgem in its recent publications acknowledges the current ambiguity surrounding the ultimate responsibility for the decommissioning costs of the gas distribution network in Great Britain.

Ofgem has actively engaged in stakeholder consultations on various decommissioning cost recovery mechanisms through its ongoing RIIO-3 regulatory process. Notably, Ofgem has opted against establishing a "decommissioning liabilities fund" or providing upfront funding via baseline revenue allowances, primarily due to significant uncertainties regarding the scope, timelines, and potential funding contributions from the UK government.

To address these costs, Ofgem has indicated that it intends to facilitate the recovery of any unexpected decommissioning costs incurred during the RIIO-3 regulatory period through its 'Heat Policy Re-opener' mechanism and/or 'Net Zero Uncertainty Mechanisms' (UM). The heat policy reopener will allow for adjustments to the regulated network's RIIO-3 revenue allowances, to reflect any policy changes related to gas network decommissioning, contingent on the UK government's heat policy strategy, which is expected to be published in 2026. Similarly, the net zero UM provides a mechanism for RIIO-3 to adapt to strategic changes in the UK government policies relating to the net zero transition.

The majority of stakeholders expressed concerns about funding decommissioning activities until greater clarity is provided by the UK government concerning decommissioning obligations and the potential for public funding. Customer advocacy groups in particular, voiced concerns regarding intergenerational equity and the potential for rising customer bills associated with decommissioning costs.

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33 https://www.aer.gov.au/system/files/2023-10/AER%20-%20Final%20-%20Pipeline%20information%20disclosure%20guidelines%20and%20Price%20reporting%20guidelines%20for%20Part%2018A%20facilities%20-%20October%202023.pdf

34 https://www.aer.gov.au/system/files/APGA%20-%20Submission%20to%20AER%20Pipeline%20Information%20Disclosure%20Guideline%20Issues%20paper%20-%209%20May%202023.pdf

5.3 Commission's position

In its Issues Paper the Commission has sought feedback from stakeholders on large scale future network decommissioning costs, and whether it would be realistic, given the current uncertainties, to address regulatory implications of this issue within the timeframe for DPP4.

The Commission noted in its position paper that the main barrier to considering decommissioning costs within the timeframe for the DPP4 reset appears to be the high degree of uncertainty over the need, nature and quantum of any costs associated with eventual decommissioning and the novel nature of mechanisms proposed to address the issue.

However, the Commission did acknowledge that early action to address this issue may provide the greatest benefit to consumers.

5.4 Frontier Economics' views

5.4.1 Principles for recovery of decommissioning costs

As a starting point, our view is that GDBs should have the opportunity to recover any efficient costs they incur in decommissioning their networks since these costs would be an unavoidable cost of providing pipeline services. The alternative would not be consistent with FCM. In our view making regulated GDBs bear the costs of asset stranding risks would also be inconsistent with what would be expected in a workably competitive market. In a workably competitive market, a business will only invest if it expects to recover all its costs, including a return. A business that is exposed to decommissioning costs – such as a business in the oil and gas industry – would not invest unless the prices it expects to receive will provide revenue to cover its expected capital and operating costs, including its expected decommissioning costs.

With respect to the timing on recovering decommissioning costs, our view is that there is less risk from taking action now to recover decommissioning costs (recognising that such action may turn out to be unnecessary) than there is from failing to take action now to recover decommissioning costs (when such may turn out to be necessary). This is because:

- It is gas customers that benefit from the use of the gas network and so it should be gas customers that pay for the full costs of the gas network, including decommissioning costs.
- If action on decommissioning costs is taken early, and proves to be unnecessary, any contributions can be returned to customers.
- If action on decommissioning costs is delayed, and decommissioning costs cannot be recovered fully from customers, there is no prospect of future recovery of these costs from customers.

A counter-argument to this might be that early recovery of decommissioning costs would lead to inequitable intergenerational cost transfers by requiring customers today to contribute to costs that will not be incurred until the future. In our view, the opposite is true. Since decommissioning is a necessary step for any asset with a finite life, our view is that any customers that benefit from the use of that asset should contribute to decommissioning costs. Whether the customer continues to use the asset until the end of its life is not relevant to whether the customer has contributed to the need for the asset owner to incur decommissioning costs. Indeed, delaying the funding of decommissioning costs until near the end of the asset's life would impose a greater burden of these costs on the smaller group of customers that remain on the network even though those customers cannot be said to have been the sole contributors to the need for the asset over to incur decommissioning costs. It is our view that providing an allowance for decommissioning costs is akin to including these costs in a long-term contract for the use of an asset; which is something that would be agreed before the asset is even built.

5.4.2 Mechanism for recovery of decommissioning costs

In our view, a sensible approach for recovery of decommissioning costs from customers over time is through a dedicated 'decommissioning liabilities fund', which would replicate the way that these costs would be recovered by a business in a workable competitive market.

We think that a decommissioning liabilities fund could operate as follows:

1. **Initial decommissioning cost estimation**: At the beginning of each regulatory period, the Commission would estimate the projected decommissioning costs ("target fund amount") for the assets, including decommissioning costs both prior to and after the end of the asset's economic life. The Commission would also estimate the remaining economic life of the gas assets – which would align with the Commission's asset stranding model.
2. **Recovering the target fund amount over time**: Once the Commission has determined the target fund amount and the number of remaining years over which to recover it, a series of annual payments would be calculated to provide cash flows that are equal in net present value terms to the target fund amount.
3. **Revenue allowance**: The Commission would then provide this set of annual payments to GDBs through the revenue allowance. The Commission would assume that the GDBs will invest the annual payments, to earn an appropriate return (equal to the discount rate assumed by the Commission when calculating the annual payments) such that, in expectation, the total accumulated funds at the time of decommissioning equals the target fund amount.
4. **Track the growth in the decommissioning liabilities fund over time**: The Commission would maintain a running balance of the notional decommissioning liabilities fund over time. This would allow the Commission to assess whether the annual payments should be adjusted up or down in subsequent regulatory periods such that the target fund amount is collected by the time decommissioning occurs.
5. **Periodic reassessment**: This process would be repeated at each regulatory reset. The Commission would re-forecast the target fund amount, given the uncertain nature of decommissioning costs. The Commission would also reassess the estimated remaining economic life of the assets and calculate the outstanding amount needed for recovery over the remaining life of the assets i.e., revised target fund amount minus accumulated annual payments.

In the event that the Commission has provided for collection of *more* funds than required, or if decommissioning is no longer required, the excess funds would be returned to customers (e.g., by way of a decrement to allowed revenues).

If the Commission has provided for collection of *less* funds than required, there is little prospect of further recovery from customers, because by the time of decommissioning there will be no customers from which to recoup those costs. If GDBs are required to fund the shortfall, this would be inconsistent with FCM. This suggests the Commission should err towards providing an allowance at the upper end of any range of cost estimates it produces. To the extent that this approach results in GDBs recovering more than the required decommissioning costs, that over-recovery can be returned to consumers (e.g., through a rebate to the most recent cohort of customers).

There are alternative approaches to recovery of decommissioning costs, including incorporating a forecast amount for decommissioning costs in the RAB and allowing a return on that amount over time. The decommissioning costs could then be recovered from customers over time (e.g., through a depreciation allowance). However, our view is that the decommissioning liabilities fund described above is a mechanism that can respond flexibly to changing information about future decommissioning costs, and would be simpler to implement.

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