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Gas DPP4 reset

Default price-quality paths for gas pipeline businesses from 1 October 2026

Final decision - reasons paper

27 May 2026

Associated documents

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13 February 2025		Open letter on Gas DPP4 2026 price-quality path reset
13 December 2023	ISBN 978-1-99-108565-8	Report on the IM review 2023 - Part 4 Input Methodologies Review 2023 - Final decision
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Foreword

We are pleased to present our final decision on the default price-quality paths for gas pipeline businesses applying from 1 October 2026 to 30 September 2031.

This reset takes place in a period of significant change. The gas sector is facing long-term decline and increasing short-term volatility, driven by developments and responses to them, including tightening supply and shifting demand through the transition to a lower-emissions economy.

We have heard clearly through consultation that many consumers wish to retain access to gas, while being concerned about both its affordability and future availability. Our decisions are anchored in the long-term interests of consumers. Delivering on this objective requires both well-calibrated regulatory settings and active, prudent responses from gas pipeline businesses.

Natural gas remains an important part of New Zealand's energy system. We expect demand to continue for some time, and that sufficient gas and supporting services can continue to be available for a large number of users beyond the next 20 years. Around 300,000 households and 13,000 businesses rely on gas pipeline networks and should have confidence in safe, reliable, and value-for-money service.

The central challenge in this reset is how to allocate costs over time in the face of declining demand. Recovering costs too quickly raises prices for current consumers, while delaying recovery increases the burden on a smaller future base and creates risks to service quality. Our decision takes into account consumer impacts, and includes shaping Vector's revenue path to smooth price increases. Overall, we expect our decision to lead to moderate price increases for most consumers.

In addressing recovery of capital costs in DPP4, we have not accepted pipeline businesses' requests to further accelerate their depreciation allowances. We have maintained the approach we commenced during the previous reset, which provides for some asset life shortening to reflect a long-term outlook of declining gas use. We have also taken steps to reduce price impacts on consumers and better share risks from large demand shocks.

We expect gas pipeline businesses to actively manage costs, innovate in how they operate and maintain their networks, and make pricing and investment decisions that support the efficient ongoing use of gas. We have set allowances at prudent levels to support efficient investment and service delivery over the regulatory period. The revenue and price paths we have set are caps, not targets, and must be applied with careful consideration of their impacts on consumers and demand.

We have taken an approach that is stable and predictable, building on the approach taken at the previous reset, while making targeted refinements to address the challenges facing the sector. We also acknowledge submissions we received on the broader regulatory regime, and consider it important that it remains fit for purpose as the sector continues to evolve.

Further issues, including network rightsizing and decommissioning, will require coordinated action across the sector. Addressing these challenges will be important to delivering orderly outcomes for consumers as the role of gas evolves.

Nathan Strong
Associate Commissioner

Executive summary

X1 This paper explains our final decision on the fourth default price-quality path (DPP4) for gas pipeline businesses (GPBs) applying for the five years from 1 October 2026. Our decision applies to Firstgas Transmission the sole gas transmission business (GTB) and Firstgas Distribution, GasNet, Powerco and Vector as gas distribution businesses (GDBs).

X2 Our decision results in broadly stable allowed revenues in real terms over the DPP4 period and we estimate it will have moderate impacts on average residential and small commercial consumer bills. It maintains incentives for GPBs to continue to provide safe and reliable services and make efficient investments, while limiting price increases for consumers during a period of uncertainty.

X3 We regulate these GPBs as natural monopolies under Part 4 of the Commerce Act 1986 (the Act) to promote the long-term interests of consumers. We do this by providing incentives to invest, innovate, and improve efficiency in the delivery of pipeline services at the quality demanded by consumers, while limiting excessive profits and sharing efficiency gains with consumers, including through lower prices.

X4 Our final decision sets revenue limits, capping GTB revenue and GDB weighted average prices, and establishes minimum quality standards. It largely retains the approach taken in the third default price-quality path (DPP3), providing continuity in regulatory settings, while incorporating targeted changes to reflect updated information and address emerging risks.

X5 Compared with our draft decision, the aggregate impact of changes is to increase total GPB allowable revenues by about 2% over the DPP4 period. Key updates include implementing a demand variation revenue adjustment (the 'hybrid mechanism') to share a limited amount of demand risk between GDBs and consumers, adjustments to expenditure allowances, updated base year inputs and modelling corrections, and further smoothing of Vector's revenue path to manage near-term price impacts.

X6 DPP4 has been set in the context of increasing uncertainty and a long-term decline in both gas supply and demand. Our decision responds to current conditions while maintaining a stable and predictable regulatory framework that can accommodate future developments, including short-term volatility, without requiring frequent adjustment.

Overview of our decision

Our final decision provides stable and predictable regulatory settings in a period of uncertainty

X7 DPP4 provides predictable regulatory settings and continuity in a period of increased uncertainty in gas supply, demand, and policy. It responds to current conditions while maintaining a stable framework that can accommodate future developments. It addresses the implications of this uncertainty for investment incentives, cost recovery and price stability, and builds on the approach taken at the last reset (DPP3).

There is ongoing demand for pipeline services despite long-term decline

X8 The long-term outlook is for a significant reduction in gas consumption over the coming decades. Despite domestic gas production declining faster than expected, we expect ongoing demand for gas from households and businesses for at least the next 20 years. This presents an ongoing need for reliable gas pipeline services and continued investment in existing networks.

DPP4 allowances support ongoing investment to maintain safe and reliable gas transport

X9 The allowances and incentives in DPP4 are intended to support GPBs to continue providing safe and reliable services, make efficient investment decisions, and support ongoing use where demand for pipeline services exists.

X10 While GPBs forecast declining connection numbers and gas volumes over the next five years, there are pockets of forecast growth. We have allowed limited system growth and consumer connection-related expenditure where these are included in asset management plans (AMPs). These allowances support ongoing network utilisation where demand is clearly evidenced, and connections are net beneficial to the network and consumers.

X11 A declining limit on these categories reflects our expectation that GPBs will increasingly focus on ensuring new connections pay their way and do not impose net costs over their lifetime on the existing consumer base.

We are completing the transition to economic asset lives in DPP4

X12 The long-term outlook of declining gas use creates a risk that GPBs may not expect to recover their total efficient costs from customers over time. This could weaken incentives to invest in and maintain networks during DPP4, with adverse implications for service quality and reliability, and raises a risk of earlier-than-expected network shutdowns.

X13 We have mitigated this risk by completing the transition to shorter regulatory asset lives begun in DPP3, aligning them with expected economic lives. This brings forward some capital cost recovery to DPP4 through higher depreciation, supporting incentives for ongoing investment while demand exists. Importantly, it does not increase the total amount consumers are expected to pay over the assumed lifetimes of gas networks.

X14 The timing of cost recovery continues to be a key aspect for this reset. In reaching our final decision, we have weighed the impacts on current and future consumers, including affordability concerns. Bringing forward some costs to the current consumer base results in a more even sharing of total costs over time, reducing the likelihood that those costs fall on a smaller group of future consumers.

We have implemented targeted measures to manage demand volatility and reduce the risk of sharp price changes

X15 DPP4 includes targeted measures in transmission and distribution price paths to mitigate the impact of large demand shocks and reduce the risk of sharp price changes. For gas transmission, price path smoothing limits in-period increases while allowing full cost recovery over time. For gas distribution, we have implemented the demand variation revenue adjustment (hybrid mechanism) introduced through amendment to the GDB Input Methodologies (GDB IMs). Under the weighted average price cap (WAPC) most demand risk remains with GDBs, with a limited mechanism to share the impact of large demand shocks, above a specified threshold, with consumers. We have also applied targeted smoothing to Vector's price path, reflected in the bill impacts discussed below.

We expect our decision to contribute moderate increases in average residential and small commercial bills

X16 We have shaped GDB revenue profiles using forecast demand, resulting in initial price increases followed by flat real network prices under the WAPC. For Vector, we have applied additional smoothing to mitigate a larger initial price step, reflecting its lower starting price at the end of DPP3. This results in estimated real network price increases of around 10% per year over the first three years, followed by flat real network prices.

X17 Transmission and distribution charges together make up around one-third of residential and small commercial gas bills. On this basis, and assuming no change in other bill components, we estimate that our decision will result in an initial increase in gas bills of around 1% to 3% in real terms for most consumers. For consumers on Vector's Auckland network, the estimated increase in real terms is around 3% in each of the first 3 years. Impacts will vary depending on individual circumstances and contractual arrangements, particularly for larger commercial and industrial users.

X18 These outcomes reflect the building blocks allowances in DPP4, including resetting revenues to reflect updated efficient costs, and differences in starting price levels across networks. For most GDBs, higher depreciation is partly offset by reductions in other expenditure allowances. For Vector, relatively lower prices at the end of DPP3, reflecting earlier price path shaping. Lower demand that forecast, and less need to smooth price increases at that time, contribute to a larger initial price step now, which we have smoothed.

Some issues raised by stakeholders will be addressed outside of DPP4

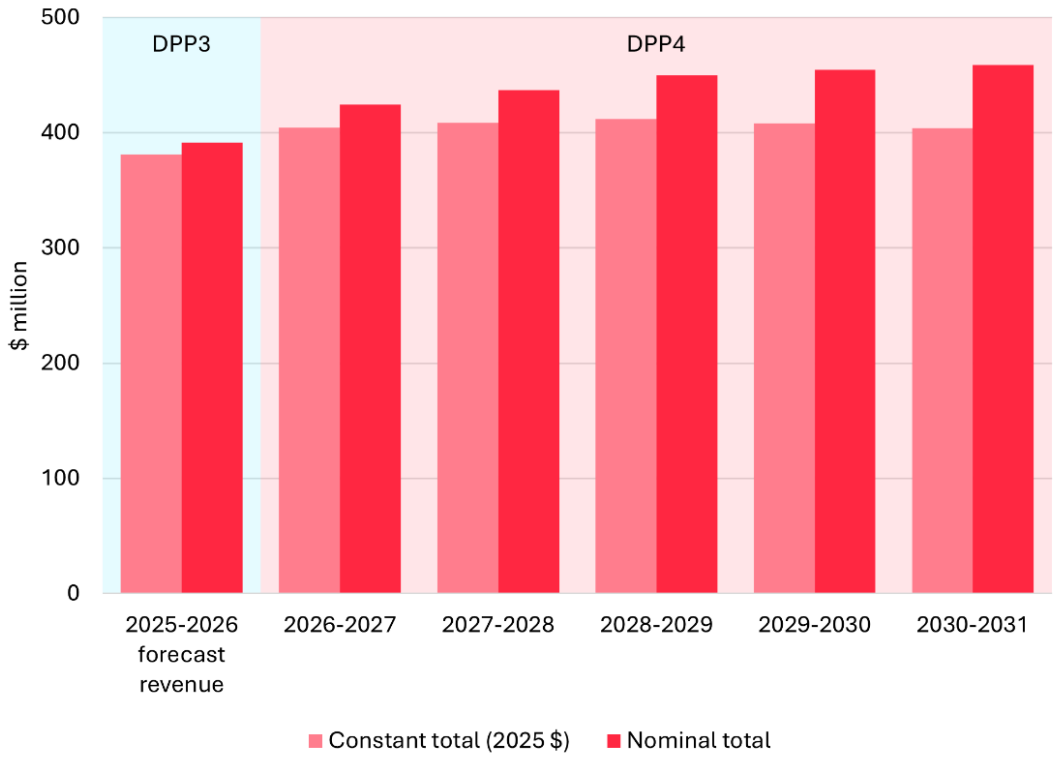
X19 Our final decision has been informed by submissions and engagement with a range of consumer and industry stakeholders. Issues raised that have not affected our final decisions for DPP4, but may be relevant to future policy development, include decommissioning, network rightsizing, the treatment of non-fixed life easements, and consumer disconnections. We expect to work with other parties, including the Ministry for Business, Innovation and Employment (MBIE) and the Gas Industry Co (GIC) on these matters.

Maximum allowed revenues in our final decision

X20 A key outcome of our final decision is the profile of maximum allowed revenue (MAR) for each GPB over the regulatory period.

X21 Figure X1 below shows total MAR for all GPBs combined. In real terms (constant 2025$)[1] the red bars show a small step up from the last year of DPP3 period (2025/2026) to the first year of DPP4 (2026/2027)[2], followed by a largely flat profile. The main increase comes from depreciation allowances due to completing the transition to economic asset lives that we started in DPP3, with a small increase in total operating expenditure (opex) allowances and a decrease in total capital expenditure (capex) allowances. The year-on-year increases in nominal values shown by the darker bars reflect forecast inflation.

Figure X1 Total maximum allowable revenue profile ($ million)



Reading this paper

X22 This paper is structured to help readers access information at different levels of detail. A summary of our decision is provided in this executive summary and in the 'decisions at a glance' tables starting on the next page. Chapter 1 outlines our regulatory role and the process for this reset, Chapter 2 sets out the context, challenges and our approach, and Chapter 3 presents our final decisions, reasons and consumer price impacts. Attachments A–H provide supporting detail and analysis.

[1] Throughout this paper, unless stated otherwise, real terms refers to constant 2025$.
[2] Here 2026/2027 refers to the period 1 October 2026 – 30 September 2027', the first regulatory year in the DPP4 period. Elsewhere we refer to regulatory years by the year of their end date, here being '2027'.

Gas DPP4 final decisions at a glance

Change relative to Gas DPP4 draft decision:	Unchanged	Update or change to input	Change of policy or implementation

#	Policy measure
DPP4 regulatory period	
T1	Set a five-year regulatory period for DPP4 from 1 October 2026 to 30 September 2031.
Price path	
P1	Set starting prices on the basis of current and projected profitability of each GPB using a building blocks allowable revenue (BBAR) model.
P2	Set a default rate of change (X-factor), relative to consumer price index as (CPI-X), of 0%.
P3	Consider setting alternative X-factors where the initial price step shock is greater than 10% in real terms. For Vector, we have applied 3-year smoothing, with10.0% steps in each of the first three years, followed by 0% real price growth rate for the remaining two years.
P4	Implement GTB IM amendments by introducing price path smoothing features, where unrecovered wash-up amounts will be deferred for future recovery.
P5	Implement the demand variation revenue adjustment (hybrid mechanism) recently added to the Gas IMs. Under the WAPC, GDBs will continue to bear all revenue risk within ±15% of consumer price index (CPI)-adjusted forecast revenue, with negative or positive impacts beyond this threshold shared 50/50 between GDBs and consumers.
P6	Forecast constant price revenue growth (CPRG) using forecasts of gas demand by consumer group that align with GDBs' forecasts of gas demand and installation control point (ICP) numbers.
P7	Set a GTB revenue smoothing limit of 10% above CPI-X, applied to current-year forecast net allowable revenue plus prior-year recoverable costs, with adjustments to preserve the revenue path and CPI.
Addressing economic network stranding risk	
A1	Maintain GPBs' incentives for continued investment to satisfy longer-term demand by gas pipeline consumers, through mitigation of economic network stranding risk.
A2	Complete the transition to shorter regulatory asset lives that we began in DPP3. This better reflects economic asset lives at DPP4, and supports ongoing provision and quality of service through expectations of credible long-term revenue recovery under our building blocks framework.
A3	Estimate the extent of asset life adjustments in DPP4 for each GPB by reapplying the 2050 and 2060 industry wind-down scenarios in our stranding model from DPP3 (and their 33:67 weightings), updating input cost variables and other technical modelling parameters.
Operating expenditure	
O1	Assess the reasonableness of a GPBs opex forecasts by comparison to a Base-Step-Trend (BST) model, and apply the lower of either outcome for each assessment period.
O2	For all GPBs set disclosure year 2025 as the base year for BST opex modelling, with adjustments for non-recurring amounts.
O3	Approve step changes which were assessed as prudent and efficient, by applying a set of factors to inform our judgement. These include whether the step change is: (a) significant; (b) adequately justified with reasonable evidence in the circumstances; (c) not captured in the other components of the DPP allowance; (d) a driver outside the control of a prudent and efficient supplier; and (e) widely applicable.
O4	Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices with no adjustment to reflect GPB-specific inflation.

Change relative to Gas DPP4 draft decision:	Unchanged	Update or change to input	Change of policy or implementation
O5	Set a partial productivity factor of 0%.		
O6	For the purpose of scaling opex with forecast growth, use each GDB's ICP forecasts, consistent with the CPRG model.		
O7	Scale base opex for forecast network length and ICP growth using the historical relationship between them, applying a 0% floor on network length changes from ICP declines, and asymmetrically weighting ICP-related reductions so that opex decreases are limited to 25% of the implied impact.		
O8	Update the elasticity factor based on the most recently available GPB data, to 0.440.		
Capital expenditure			
C1	Use the lower of each GPB's 2025 AMP forecast or the historical average (2021-2025), assessed for each year on a category-level, to forecast: asset replacement and renewals; non-network capex; reliability, safety and environment; and asset relocation capex. Except for: Firstgas Transmission's non-network capex, where the historical average is over 2020-2025; and for Powerco, for whom an additional $1 million per year is added to asset replacement and renewal historical average amount.		
C2	For all GPBs, allow system growth capex each year as the lower of 2025 AMP forecasts net of capital contributions or 50% of gross system growth capex in year one (2027) declining linearly to 40% by year five (2031).		
C3	For all GPBs, allow consumer connection capex each year as the lower of 2025 AMP forecasts net of capital contributions or 50% of gross consumer connection capex in year one (2027) declining linearly to 40% by year five (2031);		
C4		To convert capex allowances calculated on a constant 2025$ basis to nominal values, use the New Zealand Institute of Economic Research's (NZIER's) most recent Capital Goods Price Index (CGPI) inflator series, with no additional adjustment.	
C5	Include an allowance for the cost of finance, scaled in proportion to the capex allowance.		
Other inputs to the financial model[3]			
M1		Use a weighted average cost of capital (WACC) of 6.64% (5-year mid-point Vanilla WACC).	
M2	Include an allowance for disposed assets, based on historical levels.		
M3		Use base year data from 2025 Information Disclosures in our final decisions.	
M5	Include an allowance for other regulated income based on historical levels.		
Quality Standards			
QS1	Retain response time to emergencies (RTE) standard for GPBs.		
QS2	Retain major interruptions standard for the GTB.		
QS3	Do not introduce new quality standards for GPBs.		
Future issues not affecting our DPP4 final decisions			
F1	n/a	Consider network rightsizing as part of a regulatory process separate to the DPP4 reset process. Not make a specific price path allowance or introduce a new price path mechanism in relation to potential large-scale future decommissioning costs in the DPP4 reset.	
F2	n/a	Referred issues raised by submitters in relation to network decommissioning to the Council of Energy Regulators at MBIE, the regulatory system's governance group, due to the likely wider policy implications affecting New Zealand's energy sector and security.	

[3] NB: There is no decision M4 here. We have retained number M5 for consistency with earlier work.

Change relative to Gas DPP4 draft decision:		Unchanged	Update or change to input	Change of policy or implementation
F3	n/a	Defer consideration of the depreciation treatment of non-fixed life easements to the next IM review.		
F4	n/a	The proposed conceptual solution for addressing the impact of declining demand (identified by Greymouth Gas) is out of scope for the DPP4 reset. The proposed solution has been referred to MBIE due to the likely wider policy implications affecting NZ's energy sector and security.		

Chapter 1 Introduction

Purpose of this paper

1.1 This paper sets out our final decisions for the default price-quality path for gas pipeline businesses (GPBs) that will apply from 1 October 2026 (DPP4).

1.2 For DPP4 we determine the prices or revenue that regulated GPBs can recover through gas network charges as well as the quality outcomes the GPBs must meet, for the five years from 1 October 2026.[4]

1.3 In this paper we outline our regulatory role in the gas sector, the current context of the gas industry, our consideration of key issues – including what we heard in submissions on our issues paper, workshops, draft decision, targeted consultation on the hybrid mechanism – and the analysis and reasons behind our final decisions.

Our role in the gas industry

1.4 Our role includes the regulation of natural monopolies. Under Part 4 of the Commerce Act (the Act), we are responsible for price-quality (PQ) regulation of the gas pipeline services provided by gas transmission businesses (GTBs) and Gas Distribution Businesses (GDBs), collectively known as gas pipeline businesses (GPBs). Their customers are gas suppliers, retailers and large industrial users.

1.5 The transport of gas by pipelines is the only component of the gas industry where we have this type of regulatory role. We have no such role in gas exploration, production, or metering, nor in the sale of gas in either bilateral contracts, the wholesale 'spot' gas market or by gas retailers.[5]

1.6 The production of gas for use by customers begins with exploration, extraction, and processing. Gas producers located in the Taranaki region process gas for general use. The gas is then injected into high-pressure transmission pipelines (Firstgas Transmission) that stretch throughout the North Island.[6]

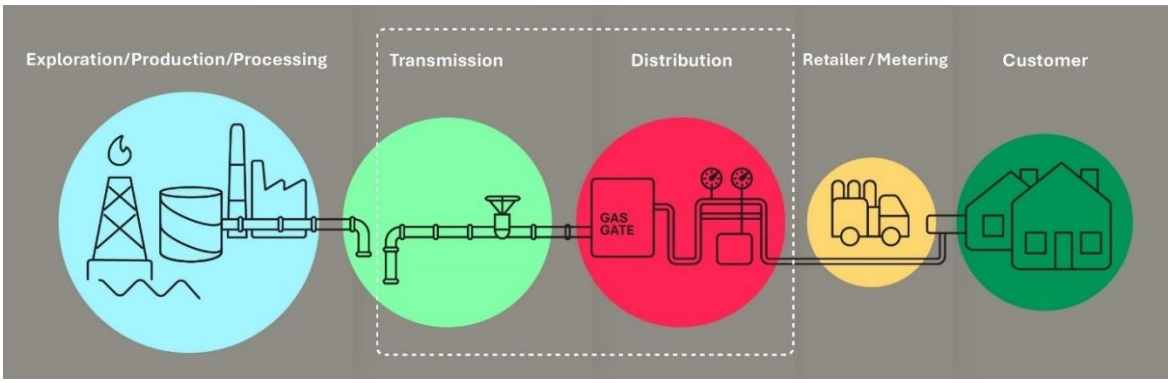
1.7 Large gas customers (eg, Methanex, Huntly power station) may connect to the transmission system directly, while local GPBs (ie., GasNet, Firstgas Distribution, Powerco and Vector) transport gas from the high-pressure transmission system to the premises of residential and business users.

[4] Our draft decision to implement a five-year regulatory period was set out in a standalone draft decision reasons paper: Commerce Commission "Gas DPP4 reset 2026 – Five-year regulatory period - Draft decision reasons paper (26 June 2025). Our final decision confirms our draft decision to set a five-year regulatory period, see Attachment A to the present paper.
[5] Noting that the Commission's wider Fair Trading and Competition functions do apply.
[6] In this paper, 'gas' refers natural gas (i.e., primarily methane) unless otherwise stated.

1.8 Gas producers sell natural gas either to retailers, or directly to large industrial users under bilateral contracts. In New Zealand, a significant share of gas is consumed by major industrial customers that have traditionally bought gas from producers under long-term contractual arrangements. Gas retailers purchase wholesale gas from producers and contract with the gas transmission operator (Firstgas Transmission) and local GDBs to transport gas from production injection points through to smaller commercial customers, businesses, and households.

1.9 Figure 1.1 below provides an illustration of the natural gas supply chain.

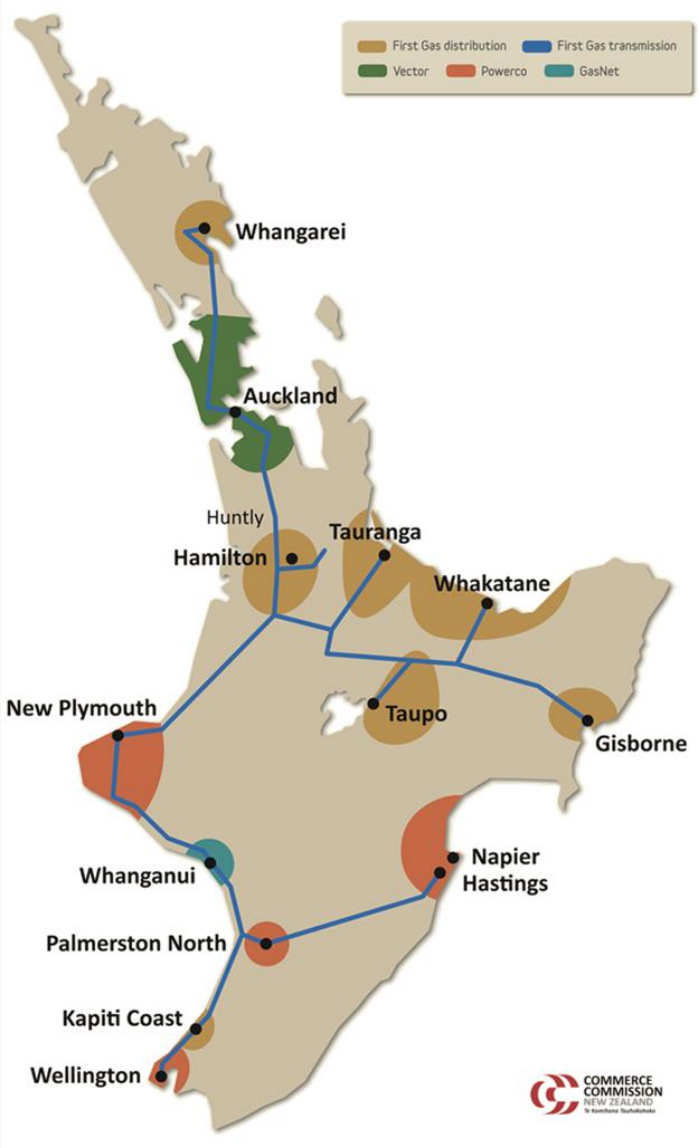
Figure 1.1 Components of the gas sector – we regulate only the GTB and GDBs



1.10 As shown in Figure 1.2 below, Firstgas is the only GTB, and owns and operates the high-pressure gas transmission pipelines. Firstgas is also a GDB, and the other GDBs are GasNet, Powerco and Vector.[7]

[7] Firstgas is regulated under DPP4 as both the GTB and a GDB. In late 2025 Clarus agreed to sell its gas businesses (including Firstgas) to Brookfield. This transaction remains subject to regulatory approvals, including Overseas Investment Office consent, and has been expected to complete in 2026. The acquisition has not yet settled, but ownership changes will not affect how the gas pipeline services provided using the purchased assets are regulated under DPP4.

Figure 1.2 Map and ownership of regulated gas pipelines in New Zealand



We set DPPs as part of price-quality regulation of gas pipeline services

1.11 Our role is to provide GPBs with incentives that promote the long-term benefit of consumers. In doing so, we are guided by our responsibilities under Part 4 of the Act. Specifically, our regulation aims to provide GPBs with incentives to innovate, invest, improve efficiency, and provide services at a quality that reflects consumers' demands, sharing efficiency gains with consumers through lower prices, and being limited in their ability to extract excessive profits.

1.12 Our primary tool for this is the default price-quality path (DPP) reset every 4-5 years, which is explicitly intended to be low-cost, with more intensive and detailed assessments available under a customised price-quality path (CPP).

1.13 The DPP includes revenue limits - implemented as a revenue cap for the GTB and a weighted average price cap (WAPC) for GDBs - and sets minimum quality standards for services to consumers. Our setting of the DPP must comply with the Gas Input Methodologies (IMs). Our final decision reflects our application of these IMs (including recent amendments to the IMs made alongside this DPP) reflecting the current context.[8]

1.14 That context includes recent falls in gas production and estimated reserves, a long-term outlook of declining gas consumption, and increased likelihood of volatility in the short-term. Volumes of gas conveyed in gas pipelines and numbers of active connections are expected to fall in the future.

1.15 As we have heard in submissions on our issues paper and draft decision, and in consumer engagement, this context presents risks and concerns to both GPBs and consumers.

1.16 We set the third default price-quality path (DPP3) for gas in 2022. In light of the uncertain outlook for GPBs at that time, we decided on a shorter, 4-year regulatory period. We also shortened average asset lives to reflect more realistic expectations of economic lifetimes. This allowed GPBs to bring forward the recovery of some of their capital costs via depreciation. We said we would make a fresh assessment of risk at the DPP4 reset.

1.17 For Gas DPP4 our focus is on setting a price-quality path that is fit-for-purpose for the next five-year period, recognising the developments that have occurred in the longer-term outlook. Our aim is to provide a sufficiently stable and predictable regime for regulated suppliers and consumers, while retaining flexibility as needed.

The gas pipeline business' revenues we set are one component of consumer gas prices

1.18 In reaching our final decision we have heard and considered consumer concerns around rising gas prices. Our DPP4 decisions relate to gas transmission and distribution charges, which together contribute about one-third of the gas bill for residential and small commercial users. Our decision does not relate to the other underlying components of gas bills, including the wholesale gas price, metering charges and retail margin. Moreover, beyond compliance with the overall maximum allowed revenues we determine, we do not regulate GPBs' pricing schedules or have any role in gas retailer pricing.

1.19 We have expressed the financial impact of our final decision on consumers by estimating the change in average residential bill for the four GDBs. This approach reflects the information available to us under our statutory remit and the relatively low-cost DPP regime. While we consider this provides a useful indication for the majority of consumers, we recognise that impacts will differ across users. In particular, we are not able to robustly estimate impacts on commercial and industrial users, including those on bespoke contracts or directly connected to the transmission network, due to data limitations and the fact that pricing decisions, by neither GPBs nor retailers, are within our regulatory oversight.

[8] Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27 (as amended) and Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28 (as amended). These include recent amendments made alongside this DPP.

Structure of this paper and attachments

1.20 Chapter 1 of this paper outlines our regulatory role and the process for setting DPP4. Chapter 2 presents the context for DPP4, and how we have approached the current outlook and uncertainty in the gas sector in making our final decisions. Chapter 3 sets out our final decisions, reasons, and consumer price impacts.

1.21 Technical analysis is contained within the following attachments:

Attachment A – Regulating prices and revenue
Attachment B – Forecasting capital expenditure
Attachment C – Forecasting operating expenditure
Attachment D – Addressing the risk of economic network stranding
Attachment E – Quality standards
Attachment F – Future issues not affecting our DPP4 final decisions
Attachment G – Other inputs into the financial modelling
Attachment H – Decision-making framework

Material published alongside this paper

1.22 Alongside this final decisions reasons paper, we are publishing two final determinations (one for the GTB and one for the GDBs) and the final decision financial modelling suite.

1.23 We have recently and separately published final decisions on two IM amendments, which are applied in the DPP4 decision:

1.23.1 gas transmission services IM amendment determination,[9] and a final IM amendment reasons paper;[10] and

1.23.2 gas distribution services IM amendment determination,[11] and a final IM amendment reasons paper.[12]

[9] Gas Transmission Services Input Methodologies Amendment Determination (No.1) 2026 [2026] NZCC 18
[10] Commerce Commission "Amendments to input methodologies for Gas Transmission Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).
[11] Gas Distribution Services Input Methodologies Amendment Determination (No.1) 2026 [2026] NZCC 17
[12] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 Gas default price-quality path – Final Decision reasons paper" (26 May 2026).

Chapter 2 Context, challenges and priorities

Purpose of this chapter

2.1 This chapter outlines the context and challenges for the fourth default price-quality path (DPP4), including what we have heard from stakeholders and the issues we consider to be priorities. It confirms that in setting DPP4 in light of this context, we must set a price path consistent with the outcomes in section 52A(a) – (d) of the Commerce Act (the Act).[13] It concludes with how this context has informed key elements in our approach to making our final decisions.

Current context and challenges for the gas sector

2.2 This section sets out our view of the current context and challenges facing the gas sector and gas pipeline businesses (GPBs). It incorporates developments since our draft decision in November 2025 and feedback in submissions on our draft decision. In places we summarise key points from our draft decision reasons paper and refer to that paper for more detail.

Overview of the context for DPP4

2.3 The gas sector is in a period of change and uncertainty in the context of declining gas production and an energy transition reflecting increased electrification. Significant cost pressures are developing for consumers. In addition to safe and reliable delivery for ongoing demand, the main forward-looking issue for consumers is how the costs of providing network services are recovered over time in a declining market.

2.4 When we set DPP3 (2022-2026), we anticipated more clarity would emerge soon after our decision about the role of gas in New Zealand's future energy mix. In DPP3 we applied a number of new regulatory settings to help mitigate the longer-term risk of GPBs economic under-recovery to maintain their incentives for efficient investment while limiting potential for excessive profits.

2.5 Since our DPP3 decision, total production across gas fields has declined faster than anticipated.[14] In a recent announcement, owners OMV expect the Māui gas field to close by the end of 2026, and other step changes in supply are possible if production at major sites fall below levels required to support their ongoing operation. Gas prices may stay high (and be volatile) if tight supply conditions continue.

[13] Commerce Act 1986, s 52A.

[14] Oil and gas reserves data released quarterly by the Ministry of Business, Innovation and Employment (MBIE) (available here) shows that natural gas reserves have been steadily declining since 2019. MBIE's annual forecasts from July 2025 indicated that natural gas production will fall short of demand by approximately 10 petajoules annually over the next three years. This shortfall reflects both accelerated field depletion and downward revisions to reserves estimates by operators. Updates in May 2026 indicate further reductions in total production for 2025 and downwards revision to forecasts. See Figure 2.1.

2.6 The full effects on production and prices of government policy changes will likely take time to materialise but may stabilise the longer-term supply outlook. These include reversing the ban on oil and gas exploration, and co-investment in new gas field development. The Government also plans to progress the development of a liquefied natural gas (LNG) import terminal in response to the Frontier electricity sector review.

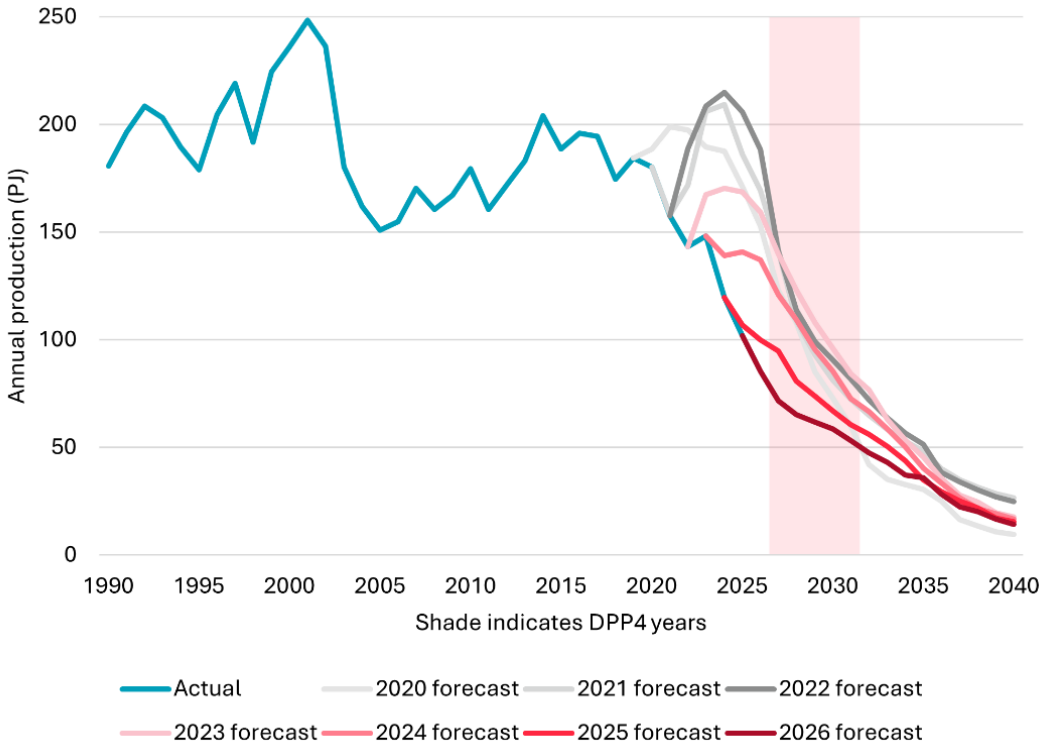
2.7 While moves to decarbonise are driving some demand reduction, gas does appear to have an ongoing role for some time as part of New Zealand's energy mix. Recent trends in consumption point to ongoing demand from industrial, commercial and residential users. This is supported by feedback from our engagement with consumers.

Forecast supply is falling faster than demand and faster than expected

2.8 With no import or export facilities, New Zealand's gas production and consumption are tightly coupled. Between 1990 – 2020 total annual production - and consumption - has varied between about 150 and 250 petajoules (PJ). The average of about 180 PJ is equivalent in energy content to about 50,000 gigawatt-hours, which exceeds New Zealand's annual electricity demand.[15]

2.9 As shown in Figure 2.1, forecasts for future gas production have steadily fallen since 2020, with some volatility in the mid-2020s. Between 2024 and 2026 updates, the proven plus probable (2P) natural gas reserves fell from 1,300 PJ to 731 PJ. Natural gas delivered from gas fields in 2025 was 85 PJ down 15% on earlier estimates.[16]

Figure 2.1 Gas production profile and MBIE forecasts from 1 January 2020 through 1 January 2026[17]



[15] Annual electricity demand has been c. 40,000 GWh since 2011. MBIE, Electricity Statistics (May 2026)
[16] MBIE "Gas reserves decline to lowest level on record" (14 May 2026).
[17] MBIE, Energy in New Zealand 2025; MBIE, Petroleum reserves data (May 2026)

2.10 As shown in Table 2.1 total production over the DPP4 period (approximated here as calendar years 2027-2031) in these forecasts has worsened over time, with slowing growth up until 2023, then year-on-year declines since then.[18]

Table 2.1 Change in forecast gas production (PJ) in the DPP4 period from MBIE gas statistics[19]

Date of forecast	Total production (PJ) DPP4 (2027 - 2031)	Year-on-year change
1 Jan 2020	449	
1 Jan 2021	496	11%
1 Jan 2022	526	6%
1 Jan 2023	551	5%
1 Jan 2024	484	-12%
1 Jan 2025	377	-22%
1 Jan 2026	310	-18%

2.11 The recent decline in supply and estimated reserves has increased uncertainty for gas sector participants, causing some retailers to exit the market or refuse new customers, and raising wholesale gas prices for consumers.[20]

2.12 While some onshore fields forecast ongoing reserves, the supply reduction reflects the decline of volume from New Zealand's largest producing field, the OMV-operated Māui field (see below).

2.13 Within this context, our focus is on the future outlook for gas pipeline services. This is not a simple picture.

The Māui gas field is now expected to close around the end of 2026

2.14 In a development since our draft decision, OMV has announced that gas production from its Māui gas field is likely to cease around the end of 2026. The exact end date will depend on late-life field performance.

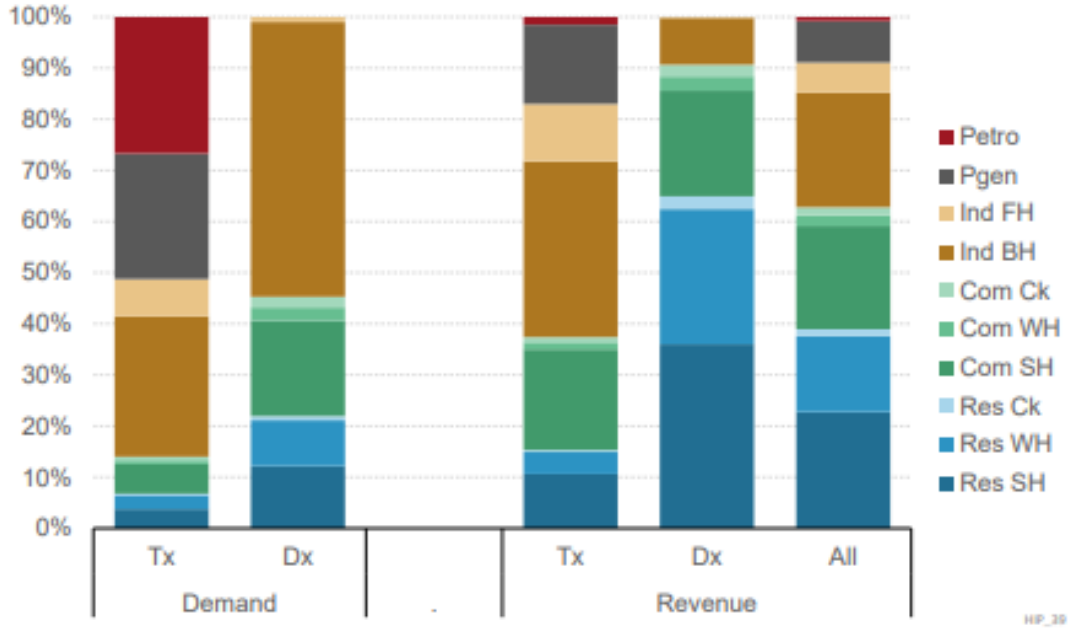
2.15 This will remove about 40-50 terajoules (TJ) per day of gas supply, with Māui producing 17 PJ in 2024. It is widely expected that Māui's shutdown will result in a closely timed shutdown of methanol producer Methanex, New Zealand's largest user of gas and provider of demand-side flexibility (whereby it can reduce or cease gas consumption to make gas available to other users). Methanex recently wrote-down the value of its NZ operation.[21] The impact of both closures will depend on timing, with the potential for non-Māui gas currently used by Methanex to become available to the market.

[18] Calendar years 2027-2031 is here the closest match to the DPP4 period 1 Oct 2026 to 30 Sept 2031.
[19] MBIE, Gas statistics webpage, (updated 14 May 2026)
[20] MGUG "Re: Open letter on gas DPP4 2026 price-quality path reset" (13 March 2025), para 11.
[21] Methanex Corporation "First Quarter 2026 Financial Statements and MD&A" (for the period ended 31 March 2026), pg. 31.

2.16 A Māui field closure was anticipated in our draft decision, in line with government data last year projecting Māui would continue producing until the end of 2027. While a firming of the closure date removes some timing uncertainty, it has not materially impacted our final decision for price paths and quality standards under DPP4.

2.17 Tightening supply is impacting gas prices and gas is used as a fuel and chemical input by a wide range of residential, commercial and industrial consumers. The consumer segment split of usage and revenue is shown in Figure 2.2 below from Concept analysis of MBIE, Commission, First Gas and Energy Efficiency and Conservation Authority (EECA) data.

Figure 2.2 Sectoral and usge split of gas demand and contributions to pipeline revenues for Transmission (Tx) and Distribution (Dx) [22]

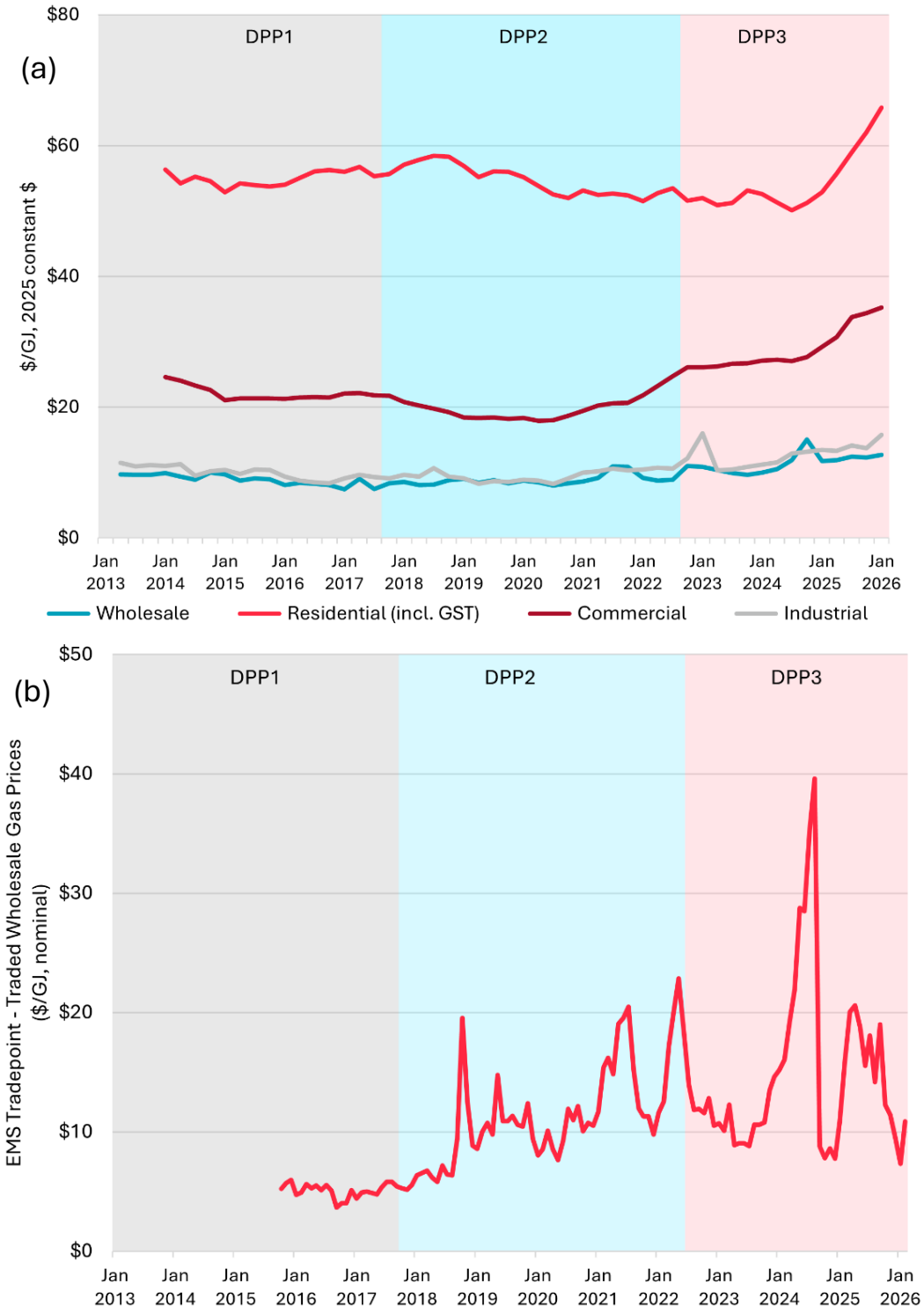


2.18 Figure 2.2 shows that residential consumers contribute an outsized share of revenues compared to their usage share. This in part reflects their very large share of the number of connections and associated costs to serve. In contrast, the small number of petrochemical and power generation users contribute less to revenues than their usage share to transmission revenues, and nothing to distribution revenues because they are not connected to, and do not use, distribution networks.

2.19 All consumer segments are now facing gas price increases. As shown in Figure 2.3(a), residential gas prices have generally declined in real terms since 2018 until an increase of about 20% in the first half of 2025. These increases reflect a combination of factors, including higher input gas costs and earlier network price adjustments following the DPP3 reset. Commercial gas prices are now about double 2020 prices, in real terms.

[22] Concept Consulting Group Ltd "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (22 August 2025), prepared for the Commerce Commission. Sector codes here are: Petro – large petro-chemical usage; Pgen – power generation; Ind – Industrial, Com – Commercial, Res – Residential. Usage codes are BH – boiling heat, FH – high temperature furnace heat; Ck – cooking, WH – water heating, and SH – space heating.

Figure 2.3 (a) Public gas pricing from MBIE prices[23] and (b) from GIC reporting of EMS Tradepoint prices - for the 5% of wholesale market traded on the etp platform, an indication of marginal gas price for large participants[24]



[23] Residential and Commercial prices here are trailing 4-quarter averages, to smooth out seasonal variations in the MBIE data related to how fixed costs are spread over the volumes of gas used. The residential March 2017 residential price appears anomalous and we have replaced it with an average of March 2016 and March 2018.

[24] See Gas Industry Co (GIC) website (accessed 20 May 2026).

2.20 Industrial and wholesale prices are both up about 50% since 2020. As published by the Gas Industry Co (GIC), there are high price increases and volatility in the price of gas traded on the Energy Market Services (EMS) platform shown in Figure 2.3(b).[25] With about 5% of wholesale gas traded on the EMS platform, this is a proxy for the marginal wholesale gas price. It shows an upward trend in recent years with high price spikes at times of increased demand for power generation.

2.21 With the recent rises in the cost of living, both businesses and households are exploring ways to reduce their energy expenses. The potential for prolonged, elevated gas prices can have knock-on effects on demand, as businesses weigh up their options to reduce input costs.

2.22 Large gas users have bilateral contracts with producers. While the details of these contracts are not generally public, we understand that new and renewed contracts are currently priced well above previous terms and in some cases have not been available.

2.23 Submissions from large users indicate that energy costs have increased materially in recent years and are expected to rise further, although impacts vary across firms. For example, NZ Steel reported significant increases in transmission and distribution costs over DPP3, with further increases expected in DPP4.[26]

2.24 Higher energy costs and tightening gas supply have contributed to reduced demand from some large industrial users, including curtailment, scaling back, and uncertainty about continued operations. This includes developments affecting major users such as Methanex and Ballance Agri-Nutrients, and reflects wider uncertainty about gas availability, including the expected closure date of the Māui gas field.

2.25 Methanex has historically played an important role in providing flexibility to the energy system, including by curtailing production to free up gas for electricity generation during periods of tight supply. Changes in its operations therefore affect not only total demand, but also the availability of flexible gas supply to support electricity system security.

2.26 Ballance Agri-Nutrients' experience highlights the challenges faced by industrial users in securing affordable long-term gas supply.

2.27 Both scenarios in the GIC's 2026 Supply and Demand Study has Methanex and Ballance closing by the end of 2027, and more generally indicate that demand outcomes for large industrial users are sensitive to future gas availability, with increased supply uncertainty increasing the likelihood of reduced industrial gas use over time.

2.28 One response to price and availability pressures is to consider electrification. For many businesses, this may not be the best option due to specific industrial processes which require gas, or the costs and/or limited availability of an electric technology option.[27]

[25] See Gas Industry Co (GIC) website (May 2026).
[26] New Zealand Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026), pp 2-3.
[27] ALENZ, "Submission on Gas DPP4 Open letter" (12 March 2025), para 6; Fonterra " Submission on Gas DPP4 Open letter" (14 March 2025), para 4; MGUG " Submission on Gas DPP4 Open letter" (13 March 2025), para 13, 23; Commerce Commission "Summary of our kōrero with residential consumer advocates, 22 September 2025" (24 November 2025)

Transition to net zero and alternative uses for gas pipelines

2.29 While it is generally accepted that achieving the Government's legislated net zero 2050 target will involve a significant reduction of carbon-emitting fuels like natural gas, the pace of this reduction and the role renewable gases may play in the future of the networks is uncertain.

2.30 In December 2024 the Government released its second emissions reduction plan (ERP2) which signals an anticipated reduction in natural gas consumption as more current users switch to renewable energy sources.[28] However, it also indicates that gas could have a role to play in electricity generation out to 2050.[29] This position has been firmed recently by advancing plans for an LNG import terminal, discussed below.

2.31 ERP2 also signals a potential role for landfill gas capture, biogas and hydrogen as fuel substitutes and carbon capture, utilisation and storage (CCUS) in reducing emissions. However, the pace and scale of uptake remain uncertain, as these technologies depend on commercial viability.[30]

2.32 Industry body GasNZ released a Biomethane Strategy and Action Plan to government in March 2026, outlining its view that biomethane production could scale from around 1 PJ per year from existing waste-based sources to as much as 25 PJ by 2050. This strategy presents biomethane as a potential partial substitute for declining natural gas supply using existing infrastructure, while recognising that achieving this scale would depend on future policy, regulatory and investment settings.[31]

2.33 Recent government policy changes have been more supportive of gas as a fuel, including removing the ban on offshore gas exploration, the $200m co-investment fund announced in the 2025 Budget for new gas fields being widened in scope to include development of existing fields.[32] The Government also plans to progress the development of an LNG import terminal. The effects of these steps on production and gas prices will likely take time to materialise but may bolster the economic outlook for gas and gas pipeline operators.

[28] Ministry for the Environment "Our journey towards net zero – New Zealand's second emissions reduction plan 2026-30" (11 December 2024)
[29] Ministry for the Environment "Our journey towards net zero – New Zealand's second emissions reduction plan 2026-30" (11 December 2024), p. 37.
[30] For examples, see Ministry for the Environment "Our journey towards net zero – New Zealand's second emissions reduction plan 2026-30" (11 December 2024), pp. 39 and 40.
[31] Gas New Zealand "Biomethane strategy presented to government" (17 March 2026).
[32] The $200 million Gas Security Fund, originally intended for new gas field developments, will now support a portfolio of investments, including: short-term drilling in existing fields, onshore exploration and appraisal drilling, long-term greenfield exploration beyond Taranaki and gas storage projects for energy security. See New Zealand Government, Hon Chris Bishop and Hon Shane Jones "Widened scope for co-investment in new gas" (6 November 2025) (6 November 2025).

Government Energy Package following the Frontier report

2.34 At the end of September 2025, the Government released a report it had commissioned by Frontier Economics on the electricity market (Frontier report) and its response (Energy Package).[33] The scope of the Frontier report and Energy Package extended to parts of the gas sector due to the use of gas in electricity generation.

2.35 Actions in the Energy Package which relate to gas pipelines included:[34]

2.35.1 Improved reporting and transparency of gas reserves and production. Through publishing additional information via a public gas market dashboard, improving transparency around reserves, production, and supply-demand dynamics; and ensuring the GIC produces an annual gas supply and demand study.

2.35.2 Considering expressions of interest to develop LNG import infrastructure. In response to medium term security of supply issues, the Government has undertaken a formal procurement process for an LNG import facility. Landed gas would be conveyed in existing gas pipelines, supporting and potentially extending the expected economic lives of network assets.

2.35.3 A new framework to incentivise investment in firm electricity generation is being developed. This may include gas-fired generation and could influence future gas demand and the future use and economics of pipeline assets.

What we have heard from stakeholder engagements

2.36 Our final decision has been informed by submissions on our Open letter, issues paper, draft decision and consultation on amending the Gas IMs, including the hybrid price path mechanism, as well as an online technical modelling workshop with GPBs and stakeholders.[35] We also engaged with industry experts and consumer groups, including targeted engagement with gas users of different types and sizes.[36]

2.37 Across these engagements, a consistent message was that affordability is now the primary concern for many consumers, overtaking reliability and security (which we measure as the quality dimensions of gas pipeline services). This includes both the ongoing cost of using gas and the cost and feasibility of transitioning to alternative energy sources.[37] We have taken these considerations into account, including when assessing the persistence of demand and decisions relating to revenue allowances and smoothing.

[33] Frontier Economics "Review of Electricity Market Performance – Final Report to Ministers & MBIE" (23 May 2025) and Ministry of Business, Innovation and Employment "At a glance: New Zealand's Energy Package" (1 October 2025).
[34] Ministry of Business, Innovation and Employment "At a glance: New Zealand's Energy Package" (1 October 2025).
[35] You can find submissions on our Open Letter, Issues paper and Draft Decisions on our website.
[36] You can find summaries of recent consumer engagements on our website.
[37] Commerce Commission "Gas DPP4 Summary of Consumer kōrero - 22 Sept 2025" (20 November 2025).

2.38 Beyond pricing, we have also heard that reducing exposure to gas market risks is increasingly influencing decision-making. This involves balancing supply risk against transition costs. For example, in announcing the electrification of its Whareroa factory, Fonterra noted that while it is protected by long-term contracts, the pace of gas depletion has heightened supply risk and accelerated plans to reduce gas use.[38] At the same time, Fonterra emphasised in its submission on our Open letter that it remains heavily reliant on gas across its North Island operations. Fonterra has more than 70 boilers and process heaters (around 750 megawatts (MW) of capacity) in use, and expects to continue using many of these assets for the foreseeable future.[39]

Submissions on our draft decision

2.39 We received 19 submissions (including 7 expert reports) and 10 cross-submissions (including 2 expert reports) on our DPP4 draft decision. We have considered these submissions and cross-submissions in reaching our final decision.

2.40 Submissions and cross-submissions on our draft decision generally focused on a small number of issues related to setting the DPP in the face of uncertainty. Submitters generally agreed that conditions facing GPBs and the gas sector have changed since previous DPP resets, but differed on the appropriate regulatory response, particularly in relation to the timing of cost recovery and risk allocation.

2.41 We engage with submissions on those and other particular topics in more detail in the Attachments, and in Chapter 3 where we present our final decisions, reasons and outcomes. We respond below to some points in submissions of a broader nature.

Sector outlook

2.42 Submitters broadly agreed that the gas sector is subject to a large amount of uncertainty, reflecting declining gas supply, decarbonisation policies, and evolving demand.[40] Most submitters accepted that long-lived gas infrastructure faces a higher risk of under-utilisation over time. However, views differed on the implications for DPP4, including the extent of measures required to mitigate network stranding risk.

2.43 As set out in our IM amendment (hybrid mechanism) final decision, our overall view is that while the long-term outlook for the gas sector remains one of gradual decline, the exact trajectory is unknown, and we consider that near-term uncertainty and the likelihood of abrupt supply or demand changes within the DPP4 period have increased relative to previous resets.[41]

[38] RNZ "Fonterra announces plans to slash fossil gas use by 38%" (29 January 2025).
[39] Fonterra "Submission - Gas DPP4 2026 Draft decision" (22 January 2026).
[40] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), pp 6–8; Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), pp9–10.
[41] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026)

Assessing impacts on consumers

2.44 Large user and consumer-facing submissions raised concerns about the way estimated consumer impacts of our draft decision were presented, using an average residential consumer measure only.[42] Major Gas Users Group (MGUG), New Zealand Steel and Optima Energy submitted that there is a lack of transparency over price impacts for medium to large gas customers who they argue will absorb more of the MAR increases, with adverse effects for the wider New Zealand economy.[43] New Zealand Steel presented numbers illustrating the magnitude of its own gas cost increases.[44] Entrust and Mercury expressed fairness concerns about some future gas users (eg. low income, renters) inevitably facing high prices.[45]

2.45 We acknowledge these concerns. However, as noted by Firstgas in its cross-submission, our approach of assessing and communicating the impacts of our decisions via the average residential price change is widely used – both by us and other regulators, and helps make outcomes more accessible to a wide audience.[46]

2.46 We set limits on revenues not individual prices, which - as noted by Firstgas - regulated suppliers can adjust to ameliorate impacts on some customer classes or increase revenue recovery from others, and retailers ultimately decide how network price changes flow onto consumers.[47] This means that while we recognise that there will be distributional impacts on residential and other consumer bills from our decision, there are limits on what we can accurately assess. Firstgas also notes that higher percentage price increases may reflect lower starting levels of network charges, with its comparatively lower revenue per customer meaning larger increases now may partly reflect a lower initial base.[48]

2.47 In its submission on the revised draft decision (hybrid mechanism) Vector noted that under a weighted average price cap (WAPC), updated supplier revenue information could result in higher starting price changes than suggested by our draft decision where end-of-period revenues are not finalised. In light of this and broader submitter comments on accurately reflecting consumer price effects,[49] we have refined our estimates of average residential consumer price impacts in the final decision.

[42] For example, MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026) p. 7; NZ Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026), p. 3.
[43] MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), p 5 ff; NZ Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026), p. 2; Optima Energy "Submission to The Commerce Commission re Gas Pipeline Pricing" (22 January 2026), p. 2.
[44] NZ Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026), pp 2-3.
[45] Entrust "Gas price reset needs to ensure investment cost-recovery in face of decreasing demand" (22 January 2026), p. 2; Mercury, "Submission on Gas DPP4 draft decision", (16 January 2026), p. 1-2.
[46] Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), p. 6.
[47] Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), p. 7.
[48] Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), p. 7.
[49] Arete Consulting "Re: Revised Draft Default Price-Quality Path Determination" (21 April 2026).

Investor behaviour and market evidence

2.48 Some submitters suggested that investor behaviour should be considered when assessing future risks, and in particular cited the recent Brookfield/Clarus acquisition as evidence that investors do not regard gas network stranding risk as material.[50]

2.49 Other submitters, including Firstgas in its cross-submission, noted that the transaction does not remove the possibility of adverse future outcomes, and investor motivations may reflect a range of factors including diversification, expected regulatory actions, or option value rather than embodying a specific view about exposure to long-term gas demand uncertainty.[51]

2.50 The transaction was a group acquisition of different business units, and the price, commercial terms, motivations and outlook of the parties are not public. We understand the transaction was also subject to conditions. We have not placed weight on this transaction as part of our decision on network stranding for DPP4.

Broader issues raised in submissions on the draft decision

2.51 We acknowledge that in submissions at various points of this reset process, some stakeholders raised broader concerns with our regulatory framework and approach. These included the underlying assumptions and analytical methods used, whether it adequately promotes the long-term benefit of consumers in current circumstances, and whether the framework is suited to a transitioning or declining industry.

2.52 MGUG, and Arete Consulting Limited in its submission on our hybrid mechanism consultation, raised a number of interrelated concerns about the overall design and application of the framework. They consider our approach places insufficient weight on near-term consumer affordability and distributional impacts and relies on analytical constructs—such as financial capital maintenance (FCM), net present value (NPV) neutrality and "notional firm" models that do not adequately reflect the lived experience of consumers or observed market outcomes.[52]

2.53 They consider this can place undue emphasis on supplier cost recovery and aggregate revenue outcomes, rather than prices faced by different customer groups, and may result in front-loading costs onto current consumers and outcomes that constrain future options.

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[50] Fonterra "Submission - Gas DPP4 Draft Decision" (22 January 2026); MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), p. 1; paras 30, 43; Castalia (report prepared for MGUG) "Evidence-based assessment of accelerated depreciation of gas transmission and distribution networks" (22 January 2026), pp. 6, 18-19, 37-40; NZ Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026), pp. 1-2; Greymouth Gas "Submission on Re: Gas DPP4 2026: Views in response to issues paper" (27 July 2025), pp. 1-2, 5; Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026).

[51] Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), pp. 10-12; Vector "Cross -submission on the default price-quality path for gas pipeline businesses beginning 2026" (12 February 2026), p.5, paras 21-24.

[52] MGUG "Re: Cross-submission on Gas DPP4 draft decision" (12 February 2026), pp. 4–5, 17; MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), pp. 4–6; Arete Consulting "Hybrid mechanism and IM amendment submission" (21 April 2026).

2.54 Other submitters also questioned whether the existing framework remains fit for purpose in a declining or transitional context. In different ways, Powerco, Entrust and Greymouth Gas called for more adaptive approaches to respond to increasing uncertainty and declining demand, or suggested that more substantive changes to the framework may be required over time.[53] A concern of MGUG and Greymouth Gas is that regulating gas operations separately from wider energy business (eg, including electricity distribution) may not take into account relevant incentives and overall risk.[54]

2.55 We acknowledge these and related points. However, these concerns largely relate to the overall design of the Part 4 regime, including the IMs and broader statutory framework. They are not matters that can typically be addressed within a DPP reset, which applies the existing framework rather than redesigning it. Where relevant, we have taken wider points into account within those limits. Proposals involving more fundamental changes are matters for wider policy or legislative processes.[55]

Consumer engagement

2.56 Ahead of our draft decision we engaged with a range of consumers and consumer groups, including the Gas User Forum hosted by the NZ Business Energy Council in August 2025, individual conversations with a range of medium to large businesses and a kōrero with consumer advocates.

2.57 This engagement highlighted differing experiences across consumer segments, reflecting variation in scale, flexibility, and exposure to energy costs. Key points from these engagements are summarised below, with further detail provided in our draft decision reasons paper.[56]

2.58 Overall, engagement indicated that many consumers expect to continue using gas in the short to medium term, but are facing increasing cost pressures, supply uncertainty, and constraints on their ability to transition away from gas. We have considered the concerns and issues below, but a full and coordinated response to them is beyond our regulatory role.

[53] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer (22 January 2026), pp.12–13; Powerco "A stable regulatory environment is the best response to issues raised in submissions" (12 February 2026), p.3; Entrust "Gas price reset needs to ensure investment cost-recovery in face of decreasing demand"(21 January 2026), p.3; Greymouth Gas "Submission on Gas DPP4 2026 issues paper" (27 July 2025), pp.1–2

[54] MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), p. 24; Greymouth Gas "Re: Gas DPP4 2026 - Views in response to issues paper" (27 July 2025), p. 2 ff.

[55] Some stakeholders were of the view that a more managed and orderly long-term transition away from natural gas would be desirable to achieve a least cost/more equitable transition to a decarbonised economy, although this would likely require political co-ordination and occur outside the existing provisions of the Commerce Act: Mercury, submission, p.2; Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 – Draft decision" (22 January 2026).

[56] Commerce Commission "Gas DPP4 reset 2026 – Default price-quality paths for gas pipeline businesses from 1 October 2026 – Draft decision reasons paper" (27 November 2025), pp. 21-23.

Industrial and commercial users

2.59 Engagement with industrial and commercial gas users, including through the Gas User Forum hosted by the New Zealand Business Energy Council and follow-up discussions with medium to large businesses, highlighted significant concern about both gas cost increases and supply uncertainty. Participants reported that gas prices had more than doubled over the past five years in some cases, with survey responses indicating prices above $25/gigajoule (GJ) for some users, and increases in contracted prices of around 50–200%.

2.60 These users emphasised the near-term nature of these challenges. Many contracts are due to expire by around 2027, creating a relatively short window for planning and investment decisions. Businesses reported difficulty securing supply, with some receiving only one or no tenders, and increasing reliance on short-term or uncertain contracting arrangements.

2.61 Across both industrial and commercial users, there was a consistent view that options to transition away from gas are limited in the short term. Electrification was often described as uneconomic or impractical due to site-specific requirements or electricity network capacity constraints, with some firms facing significant connection or infrastructure costs. Alternative fuels such as biomass or biogas were also described as being constrained by cost, availability or regulatory barriers. As a result, some businesses reported reducing output, cutting staff, or considering a return to coal or diesel, with implications for both emissions and economic activity.

2.62 Differences between segments were primarily in degree rather than type. Large industrial users emphasised more acute risks to production, employment and international competitiveness, including a higher likelihood of exiting or scaling down operations. Medium-sized commercial users tended to report somewhat greater flexibility, but still identified significant cost pressures, contracting challenges, and barriers to further decarbonisation.

2.63 More broadly, businesses pointed to system-level concerns, including the potential for declining demand to increase costs for remaining users, the risk of stranded assets, and the need for clearer and more coordinated policy direction. Many emphasised the importance of a managed transition and greater transparency in pricing and network costs.

Residential consumers and consumer advocates

2.64 Engagement with consumer advocates highlighted the lived experience of residential gas users, particularly those facing affordability constraints. Advocates emphasised that some households, including renters, older consumers and low-income groups, have limited ability to transition away from gas due to structural factors such as housing arrangements, appliance choices and upfront costs.

2.65 Key concerns included rising energy costs, high daily line charges and disconnection fees, reported in some cases to be in the thousands of dollars, and limited access to clear and consistent information. Advocates noted that some households were reducing energy use, including hot water consumption, to manage affordability pressures, and that barriers to switching or electrification remain significant.

2.66 Participants also raised equity concerns about how network costs are allocated over time, particularly as the gas user base changes. They emphasised the importance of a managed transition, clearer policy direction and protection for vulnerable consumers.

Our approach to making final decisions for DPP4

2.67 The legal and regulatory framework under which we have made our final decision for DPP4 is set out in Attachment H. In practical terms, setting a price path involves the specification of maximum allowable revenues - specified by starting prices and rates of change - and quality standards.[57] We determine these aspects by the application of the Gas IMs to the prevailing context, outlined above.

2.68 In doing so we aim to provide regulatory stability and maintain consumer confidence, given uncertainty around the long-term outlook for the sector. In aiming for stability, we recognise the value of flexibility in being able to respond to contingencies.

We must promote the long-term benefit of consumers

2.69 We must set a price path consistent with section 52A of Part 4 of the Act.[58] That is, we must promote the long-term benefit of consumers, consistent with certain outcomes produced in competitive markets.

2.70 This means suppliers should (a) have incentives to innovate and invest; (b) have incentives to improve efficiency and provide service at a quality that reflects consumer demands; (c) share with consumers the benefits of efficiency gains, including through lower prices; and (d) be limited in their ability to extract excessive profits.

Priorities and key elements in making our final decisions

2.71 Our final decisions set out in the following chapter have been informed by the context and challenges described above, including the expectation that demand for gas pipeline services will persist while gas supply tightens further and longer-term demand for gas declines, heightened policy and market uncertainty, and increasing affordability pressures for some consumers. This section summarises the key considerations and priorities that guided our approach to setting DPP4.

2.72 We note that our decisions relate to only one component of the total cost faced by consumers using gas, namely the regulated costs of delivery through pipeline networks. Other factors affecting consumers' experience of gas, including gas supply, retail pricing, and fuel-switching choices, sit outside the scope of this DPP.

2.73 Consistent with the Part 4 purpose of promoting the long-term benefit of consumers, our approach to DPP4 reflects a need to balance near-term price impacts and predictability with efficiency, investment and operation of long-lived pipeline assets in a period of uncertainty. In doing so, we have been mindful both of what the price-quality regulatory framework is designed to do, and of its limits in responding to broader transition, policy, and demand developments.

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[57] Noting that the GDBs are subject to a weighted average price cap, where limits on allowed revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand. See Chapter 3 for more details.
[58] Commerce Act, s 52A.

2.74 In approaching this reset, we have had regard to the ex-ante expectation of maintaining FCM over time as an economic principle that informs the application of the building blocks framework. In practical terms, this involves allowing for the recovery of efficient costs and a normal return on invested capital over time, taking into account forecast demand and uncertainty over the regulatory period.

2.75 We recognise that assumptions underlying cost recovery and asset utilisation are being considered in gas networks facing declining and uncertain demand in different jurisdictions, for example in Australia and the UK. The Australian Energy Market Commission has commenced a review of its gas regulatory framework in this context, including the possible limits to FCM, and the Australian Energy Regulator has acknowledged that falling utilisation challenges regulatory frameworks developed for growth or stability.[59, 60] In the United Kingdom, the Government has similarly highlighted the need to manage declining demand while maintaining resilience, investment and affordability, and an orderly transition of the gas network.[61]

2.76 We expect GPBs to actively manage their assets and expenditure on a lowest-cost lifecycle basis. This includes reassessing asset lives, investment level and timing, and the balance between capital and operating expenditure as network utilisation changes. Our regulatory settings are intended to support this active management, rather than assume unchanged operating conditions.

2.77 Against this backdrop, our approach to assessing submitter views, evidence and trade-offs, in reaching our final decisions has included the three high-level considerations below, slightly reframed from our draft decision:[62]

2.77.1 **Supporting continued safe and reliable operation while demand persists.** We have approached decisions on expenditure allowances keeping in mind the incentives to GPBs to operate and maintain pipeline services safely and reliably for as long as consumers continue to rely on those services, while recognising that demand and utilisation are expected to change over time.

2.77.2 **Considering impacts across current and future consumers in a declining demand environment**. In profiling costs and setting allowances, we have considered how the timing of cost recovery affects both current and future consumers, including how regulatory settings influence when network costs are recovered as the customer base declines over time.

2.77.3 **Managing price and revenue risk in the presence of uncertainty.** In making our decisions, we have given weight to regulatory predictability and continuity with previous DPP resets, particularly in how allowances are set and revenues are recovered over time. While current conditions involve greater uncertainty than at previous resets, our approach generally reflects a preference for stability and continuity with past decisions unless there is a clear and compelling case for change.

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[59] Australian Energy Market Commission "Gas networks in transition – Directions paper" (19 March 2026).
[60] Australian Energy Regulator "Submission: Gas distribution network connections and declining demand" (10 July 2025), submission to the Australian Energy Market Commission.
[61] Department for Energy Security & Net Zero "Midstream gas system: update to the market" (20 June 2025).
[62] Commerce Commission, "Gas DPP4 reset 2026 Draft decision reasons paper" (27 November 2025),p 24.

Chapter 3 Setting revenue allowances and considering price impacts

Purpose of this chapter

3.1 This chapter summarises our final decisions for setting the fourth default price-quality path (DPP4) revenue allowances for the gas pipeline businesses (GPBs) and the price impacts on consumers. It presents the overall revenue outcomes of our decision and discusses the results and reasons for the components in these allowances and their profiles. It briefly discusses quality standards, which are unchanged in our final decision from the current standards. We also discuss the issues deferred for future consideration.

3.2 We note which Attachments to this paper to refer to for more details.

Overall summary of our final decision

3.3 We have assessed the current context of the gas sector, engaged extensively with stakeholders and considered submissions on our draft decision. Significant long-term uncertainty exists over the future of the gas industry in New Zealand.

3.4 In general, our view is that the outlook for the gas pipeline businesses operating in this wider context has not materially changed in a way that would cause us to significantly change our approach to DPP4 from the approach we took for DPP3.

3.5 An exception is our recent decision to amend the gas distribution business (GDB) input methodologies (IMs) to include a hybrid price path mechanism, implemented now in DPP4.[63] This reflects that, while our overall view for the gas sector is unchanged from our draft decision – namely, one of overall long-term decline with some uncertainty along the way – the likelihood of abrupt and material changes in supply or demand within the DPP4 period has increased relative to previous resets and our 2023 IM review. It remains appropriate for GDBs to bear demand risk under a weighted average price cap (WAPC), but for the reasons set out in our recent IM amendments paper[64] and outlined below from paragraph 3.129, we consider it appropriate to share some excess risk with consumers in extreme cases. In our view, in such circumstances it provides a lower cost 'release valve' than a customised price-quality path (CPP), the costs of which are recoverable from consumers, and supports incentives for ongoing investment in the face of demand shocks.

3.6 While it seems increasingly likely that large changes could occur affecting the gas sector within the DPP4 regulatory period, we expect ongoing demand by consumers for gas pipelines to deliver natural gas to homes, businesses and for power generation across the North Island through at least the next two decades.

[63] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).
[64] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).

3.7 Overall, the total maximum allowable revenue (MAR) for DPP4 is a moderate increase from DPP3 on a constant dollar basis. The main increase comes from depreciation allowances due to completing the transition to economic asset lives that we started in DPP3, with a small increase in total operating expenditure (opex) allowances and a decrease in total capital expenditure (capex) allowances.

3.8 Our decision on depreciation for DPP4 seeks to balance between the consumers of today and future consumers in paying for capital costs, mitigates network stranding risk for GPBs and maintains incentives for continuing investment needed to satisfy current and future demand by users of gas pipeline networks. We have decided that applying the same assumed network wind-down scenarios (and associated weightings) that we used in DPP3 to estimate economic asset lives and shorten regulatory asset lives, remains compatible with the evolving risk profile at this time. Shortening asset lives today reduces future depreciation costs, mitigating the risk of under-recoveries by bringing fixed network costs forward into DPP4 where they can be spread over a larger consumer base. We have not been persuaded by GPBs that even shorter timeframes should be used at DPP4 to depreciate assets over.

3.9 The ways we have taken consumer impacts into account include our constraining of expenditure allowances, and in our shaping of the overall maximum revenues that GPBs can recover. We have profiled this in two ways related to consumer price impacts:

3.9.1 our constant price revenue growth (CPRG) approach shapes revenue in aggregate so that it follows demand across the DPP4 period.[65] This provides constant weighted average prices within the period, and under a WAPC protects consumers from price increases even if demand falls; and

3.9.2 we have further shaped the revenue profile where, under the approach above, we consider the initial staring price adjustment is too large. This applies only to Vector, where we have moderated the initial price adjustment by evenly smoothing increases over the first three years, followed by two years of flat real prices.

3.10 These outcomes reflect the building block allowances in DPP4, including the reset of revenues to update efficient costs, and differences in starting price levels across networks. For most GDBs, higher depreciation is partly offset by reductions in other expenditure allowances. For Vector, relatively lower prices at the end of DPP3 reflect its earlier price path shaping and the fact that it had already reduced costs at that time, meaning there was less need to smooth prices than for other GDBs. This results in a larger initial price step, which we have smoothed.

3.11 Transmission and distribution charges together make up around one-third of residential and small commercial gas bills. On this basis, and assuming no change in other bill components, we estimate that our decision results in total gas bill increases in real terms (ie, excluding inflation) of:

[65] While this is how we have approached our decision, the actual bill changes consumers experience will depend on a range of factors including the individual pricing changes GPBs apply, how these are passed through by retailers, and the wholesale gas price.

3.11.1 between about 1% to 3% in the first year of DPP4, followed by flat real prices, for consumers on the Firstgas Distribution, GasNet and Powerco networks; and

3.11.2 about 3% in each of the first three years, followed by two years of flat real prices, for consumers on Vector's network.

3.12 Impacts will vary depending on individual circumstances and contractual arrangements, particularly for larger commercial and industrial users connected to the Firstgas Transmission network. We do acknowledge that overall gas bills will likely move by more than this amount on the expectation that the underlying gas price will increase due to falling supply.

3.13 Quality standards are unchanged from DPP3, with the expectation that networks are maintained at current levels. After investigation, our final decision is to not introduce any new quality standards.

3.14 We expect gas disconnections to be an emerging focus over DPP4. We intend to collect information on disconnections and monitor outcomes, and note that this issue will be in scope for GIC's Future Gas Infrastructure workstream and we will engage with it on the overlap and implications of this work.

3.15 We have identified some uncertainties beyond the DPP4 period best addressed by waiting to see how the sector evolves to enable a clearer basis for decisions - and by retaining the continuity of the current path – rather than via new measures in DPP4. These include decommissioning, network rightsizing, and the depreciation treatment of non-fixed life easements.

Our approach to determining price paths for the Gas Pipeline Businesses

3.16 We are required to set maximum revenues and quality standards for each GPB for the regulatory period, as set out in s 53M of the Act. The IMs specify how we limit maximum revenues in the DPP:

3.16.1 The GTB is subject to a 'revenue cap', where maximum revenue limits do not change in response to changes in demand, and under- or over-recovery of revenue is recovered from or returned to consumers in later years.

3.16.2 The GDBs are subject to a 'WAPC', where limits on allowable revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand.

3.17 As part of this reset, we have amended the IMs related to features of both the GTB and GDB price paths which are outlined below and discussed further in Attachment A.

3.18 The two main components of the revenue limits are:

3.18.1 the 'starting price' allowed in the first year of the regulatory period; and

3.18.2 the 'rate of change' in maximum revenues allowed relative to the consumer price index (CPI), that is used to adjust the revenue allowed in subsequent years in the regulatory period.

3.19 Our 'building blocks' approach to setting revenue allowances is broadly consistent with DPP3. It involves the following main steps, detailed in Attachment A:

3.19.1 we calculate building blocks allowable revenue (BBAR) for each year so that expected revenues recover forecast efficient costs, including a return on capital;

3.19.2 we smooth the recovery of BBAR over the regulatory period so that, in present value terms, expected revenues equal the present value of BBAR. This avoids undue volatility in prices or revenues;

3.19.3 consistent with the objective of achieving relatively constant prices in real terms, we determine a starting price using forecast CPI to define a smooth real price path;

3.19.4 we may implement this smoothing through the rate of change ('X-factor'). We specify a default X-factor, as an overall productivity factor, and may set alternative rates of change to smooth the building blocks revenue across the regulatory period to minimise any undue financial hardship to the supplier or price shocks to consumers;[66] and

3.19.5 for each GDB, we apply CPRG by taking into account the profile of forecast demand. This sets the starting price such that weighted average prices remain constant in real terms, avoiding price movements driven purely by demand changes during the regulatory period.

3.20 The building blocks approach results in a MAR profile for each GPB. Table 3.1 shows the five-year time series of MAR over DPP4 for each GPB. These are set as nominal values, ie, they account for forecast inflation over the regulatory period.

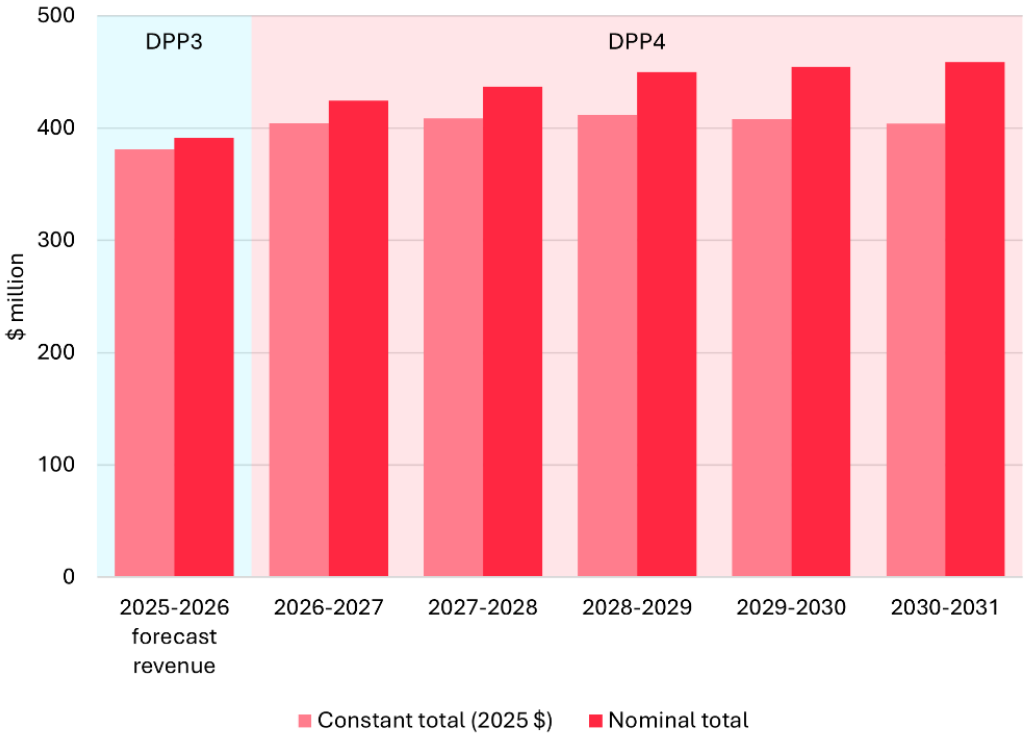
Table 3.1 Maximum allowable revenues in each year of the regulatory period ($ million, nominal)

GDB	2025/2026 forecast revenue	2026/2027	2027/2028	2028/2029	2029/2030	2030/2031
Firstgas Transmission	205.3	222.1	226.5	231.0	235.6	240.4
Firstgas Distribution	43.1	44.4	44.5	44.2	43.9	43.3
GasNet	6.0	6.7	6.8	6.9	7.0	7.0
Powerco	73.5	80.9	82.2	83.2	84.1	84.8
Vector	63.7	70.2	77.2	84.5	84.0	83.5

3.21 Figure 3.1 shows the profile of total MAR across all GPBs.

[66] Commerce Act, s 53P

Figure 3.1 Total maximum allowable revenue profile across all GPBs for DPP4 ($ million)



3.22 Table 3.2 shows the starting prices and the rates of change we have determined for each GPB. The increases in prices from 2025/26 to the first year of DPP4 are larger than the corresponding increases in the MAR, due in part to forecast volume effects. Under the WAPC, prices were effectively fixed over DPP3, while volumes declined more than forecast for some businesses (GasNet, Powerco and Vector) relative to those assumed when setting the price path. As a result, the MAR for DPP4 is recovered over a smaller forecast volume than was assumed when setting the DPP3 price path, leading to higher prices relative to those at the end of DPP3. This is a natural outcome of the WAPC, which provides price stability for consumers within a regulatory period, but can result in larger price adjustments between periods when actual volumes differ from that forecast when the previous price path was set.

3.23 Table 3.2 highlights that we have used an alternative rate of change to smooth Vector's price increases over the first 3 years of the regulatory period. We explain how we have set Vector's alternative rate of change in the section below 'Setting rates of change for the GPBs' from paragraph 3.107.

Table 3.2 Starting prices (excluding pass-through and recoverable costs) and rate of change ($ million, nominal)

GPB	Starting price ($m)	Price increase from 2025/26	Rate of change
Firstgas Transmission	222.1	CPI + 5.9%	CPI + 0%
Firstgas Distribution	44.4	CPI + 2.4%	CPI + 0%
GasNet	6.7	CPI + 10.4%	CPI + 0%
Powerco	80.9	CPI + 7.8%	CPI + 0%
Vector	70.2	CPI + 10.0%	CPI + 10.0% for years 2 and 3 then CPI + 0%

What is driving revenue

3.24 Parts of our revenue calculation are 'mechanical' in the sense that we are required to apply the IMs to specified inputs, for example regulatory asset base (RAB) values and forecast inflation (i.e., CPI). Other elements require decisions on implementation, for example how capex and opex allowances are set for the regulatory period.

3.25 In this section, we summarise the key factors and decisions driving revenue, including an assessment of their impacts relative to DPP3 revenues. For more details on our approach, and a discussion of the decisions we have taken in applying the BBAR method in our draft decision, please refer to Attachments A and G to this paper.

Expenditure allowances

3.26 Setting allowances for DPP4 is challenging because we are doing this within the context of a gas sector that is in a period of change and uncertainty.

3.27 A price-quality (PQ) determination provides a revenue allowance (set as a price or revenue cap), but not a cap on what can be spent. While we forecast opex and capex allowances separately given their different drivers, GPBs have the flexibility under our regime to substitute between opex and capex. We do not specifically allocate expenditure to particular categories, and GPBs may still prioritise expenditure in certain areas beyond the level implied by our allowances. Accordingly, we have considered the reasonableness of the expenditure profiles in aggregate and the interaction between capex and opex.

3.28 In the current environment GPBs who are investing and operating efficiently will be planning to meet expected current and future consumer demands on a least-cost lifecycle basis. While we expect increasingly active consideration by GPBs of how they may be able to extend the useful life of assets through opex approaches compared to new capex, core capex required to deliver the services at the level which consumers demand is still required.

3.29 Our approach to setting expenditure allowances for GPBs in the DPP4 period draws on the approaches we have used in the past including those employed for Electricity Distribution Business (EDB) resets, with adjustments to reflect the sector context.

We have reduced forecast capex allowances compared with DPP3

3.30 This section sets out our decisions related to capex. See Attachment B for more details. We have assessed GPBs forecast capital expenditure by category for each year against a comparable value we have derived.

3.31 Consistent with the relatively low-cost approach of setting a DPP,[67] we have assessed GPBs' forecast capital expenditure by category for each year against historical averages where appropriate. For growth-based expenditure (consumer connection and system growth capex) where historical levels are considered to be a less reliable proxy, we have applied a different approach.

3.32 As set out in Table 3.3, the capex allowances we have determined are lower than what the GPBs have historically spent and what they forecast in their 2025 AMPs to spend over DPP4.[68]

Table 3.3 Capital expenditure allowances (constant 2025 $'000)

GPB	GPB 2025 AMP forecast	DPP4 allowance	Allowance as a % of 2025 AMP forecast
Firstgas Transmission	163,922	158,967	97%
Firstgas Distribution	24,067	21,177	88%
GasNet	4,905	3,735	76%
Powerco	71,939	61,638	86%
Vector	19,786	19,043	96%
Industry total	**284,619**	**264,559**	**93%**

3.33 These capex allowances are a significant decrease from those provided at the DPP3 reset, which reflects the significant reduction in growth-based capex (consumer connection and system growth) and an increasing trend by GPBs to an opex-based approach, which in some cases results in material reductions in asset replacement and renewal capex.

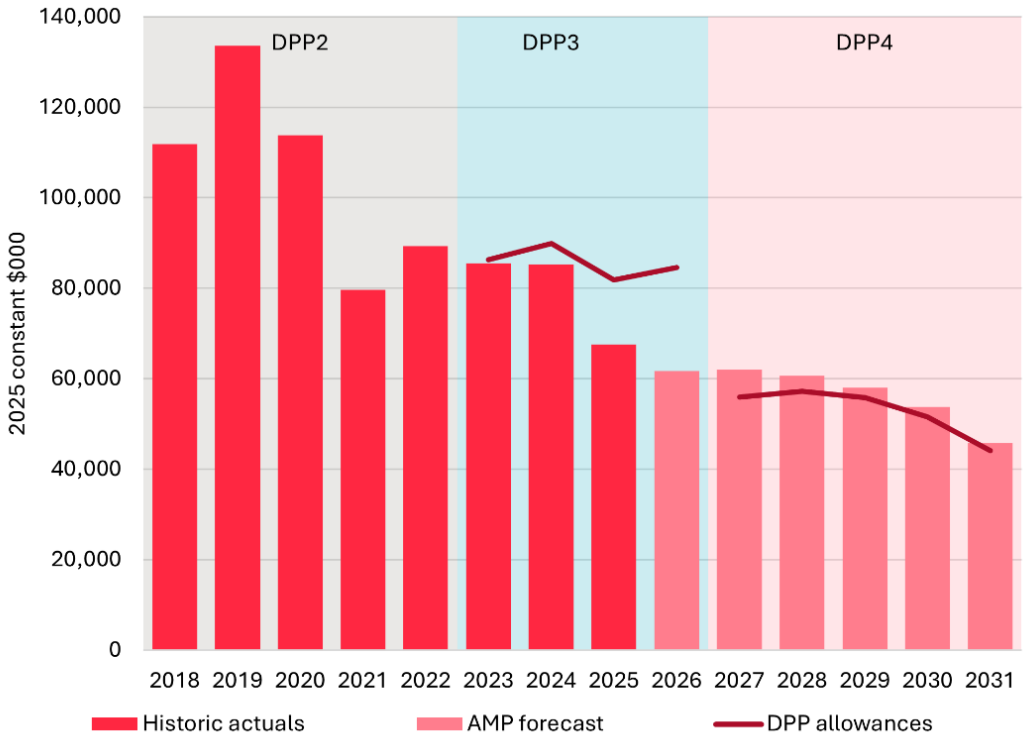
3.34 We note that the forecasted capex required varies across GPBs. This reflects different views on the ability to reduce capex through more intensive maintenance approaches, as well as differences in commercial outlooks, regional dynamics and approaches to capital contributions. We have applied a consistent assessment framework across all GPBs per capex category and included assessments of the reasonableness of underlying drivers across GPBs individually and as a sector.

[67] Commerce Act, s 53K

[68] GPBs' 2025 AMPs are available on their websites: Firstgas Transmission, Firstgas Distribution, GasNet, Powerco, Vector.

3.35 Lower acceptance rates for some GPBs reflect AMP forecasts that are maintaining or increasing historical levels of capex, whereas higher acceptance reflect GPBs that are forecasting declining capex over DPP4. Figure 3.2 below shows the capex profile for GPBs in aggregate.

Figure 3.2 Comparison of industry total actual capex, AMP capex forecast and DPP allowances (constant 2025 $'000)



3.36 Given the uncertainty facing the sector, our analysis has focused on capex categories which represent the larger proportion of expenditure and areas with the most uncertainty, in particular:

3.36.1 asset replacement and renewal (ARR) investments given the GPBs are considering opex/capex substitution to extend asset lives; and

3.36.2 system growth and consumer connections, and whether connecting new customers and growing the networks is prudent in the current environment.

3.1 Our approach to these capex categories has changed from our draft decision.

Asset replacement and renewal capex

3.2 Expenditure within the ARR category is focused on maintaining network asset integrity to maintain current quality and security of supply. Some GPBs have noted their intention to move to a greater reliance on more intensive inspections and maintenance programmes (ie. opex solutions), to defer or reduce ARR capex requirements. With different drivers on different networks, forecast costs show different profiles compared to historical levels:[69]

[69] From 2025 AMPs, available on GPB websites: Firstgas Transmission, Firstgas Distribution, GasNet, Powerco, Vector.

3.2.1 Vector has clearly identified where opex solutions may reduce expected ARR spend in future years, resulting in a forecast decline in ARR for DPP4;

3.2.2 Firstgas Distribution is maintaining ARR spend at historical levels;

3.2.3 Powerco and GasNet are forecasting ARR spend above historical levels; and

3.2.4 Firstgas Transmission has forecast a decline in ARR overall compared to historical periods.

3.3 We have largely retained the approach outlined in our draft decision for setting ARR based on a comparison of the GPB forecast to the average from the historical refence period, which we have rolled forward one year from the draft to 2021 – 2025, reflecting updated information.

3.4 We have allowed additional resilience capex for Powerco of $1 million per annum in addition to the historical average approach to address the priority resilience risks it has identified.[70] We agree that the mitigation expenditure for the identified priority projects is likely to address risks affecting a significant number of consumers. Given that these risks may involve extended outage durations if realised, the expenditure is likely to be in consumers' best interests.

3.5 There is a link between ARR capex and the opex-capex trade-off step change within our opex framework. We have not allowed opex step changes where we have not observed corresponding reductions in forecast ARR capex.

3.6 At the same time, our approach does not prevent GPBs themselves from reprioritising expenditure within their overall allowances. Where further investigation identifies that enhanced inspection and maintenance programmes deliver more efficient or sustainable long-term outcomes, GPBs retain flexibility to adjust the mix of opex and capex accordingly.

System growth and consumer connection capex

3.7 Our final decision departs from our draft decision on system growth and consumer connection capex. In the draft decision, we declined all system growth capex for all GPBs, and we limited consumer connection capex to the lower of AMP forecasts net of capital contributions and 20% of gross AMP connection capex, assessed annually.

3.8 In our final decision, we have set system growth and consumer connection capex for each GPB as the lower of the forecast net of capital contributions or at 50% of the gross AMP forecasts for 2027 declining to 40% by 2031.

[70] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), pp.17-19.

3.9 Submissions on our draft decision accepted that, in a declining demand environment, new investment should not impose costs on existing consumers. Differences focused on the appropriate level of capital contributions and the extent to which contribution requirements should be applied rigidly or with flexibility over time. Rewiring Aotearoa and Mercury submitted that providing for system growth capex was inappropriate and that new connections should be self-funded.[71]

3.10 While demand forecasts point to declining gas consumption overall, submissions showed that localised investment may still be appropriate where it is net beneficial. In particular, we have accepted information submitted which supported greater allowances for forecasted network growth, related to residential sub-division reticulation, and connecting renewable gas opportunities.[72]

3.11 Our decision was based on balancing a number of considerations, including:

3.11.1 providing GPBs flexibility to respond, including increasing network length and connections where this is beneficial to existing customers, by spreading costs over a wider number of consumers;

3.11.2 managing the risk of further asset stranding;

3.11.3 avoiding price shocks which may materially change developer or consumer gas sentiment by considering impact of step change in customer contributions compared to a graduated decline; and

3.11.4 the potential role of renewable gas in providing long-term value to gas networks (system growth only).

3.12 For both system growth and connection capex we have applied a cap against the gross value which gradually tightens each year over the DPP4 period. The change in the cap reflects our expectation that GPBs will progressively increase expectations on capital contributions to further manage exposure to network stranding risk.

3.13 We observe that GDBs face different network characteristics, customer mixes, and future outlooks, and that their connection policies reflect differing strategies for managing demand uncertainty and exposure to stranding risk within the regulatory framework.

3.14 Other capex categories have considered the forecasted level compared to the historical average. Further detail on our capex decisions is set out in Attachment B.

We have provided small increases in opex allowances from DPP3

3.15 Opex allowances provide for GPBs to fund activities that are not capex, including activities essential to network operation such as maintenance and planning. Our decisions on opex are summarised below. See Attachment C for more details and discussion.

[71] Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 - DPP4 Draft Decision" (22 January 2026), p. 2.; Mercury "Submission on Gas DPP4 draft decision" (16 January 2026), p. 1.
[72] Some of this information was submitted confidentially, due to commercial sensitivity.

3.16 We have used a base-step-trend (BST) approach to compare to GPBs' forecasts and have used the lower value of these for each year of the regulatory period to set GPBs forecast opex allowances over the DPP4 regulatory period.

3.17 We consider the BST approach is appropriate as opex is generally related to more recurring expenditure compared with capex, which can be variable from year-to-year reflecting the potential for more 'lumpy' capital projects. Our BST approach uses opex for a recently completed year as the starting base year (2025) for ongoing costs, making step adjustments for approved additional activities or to account for costs or savings from the base year which are not likely to recur in DPP4, and applying trend factors to capture underlying drivers of changes in cost.

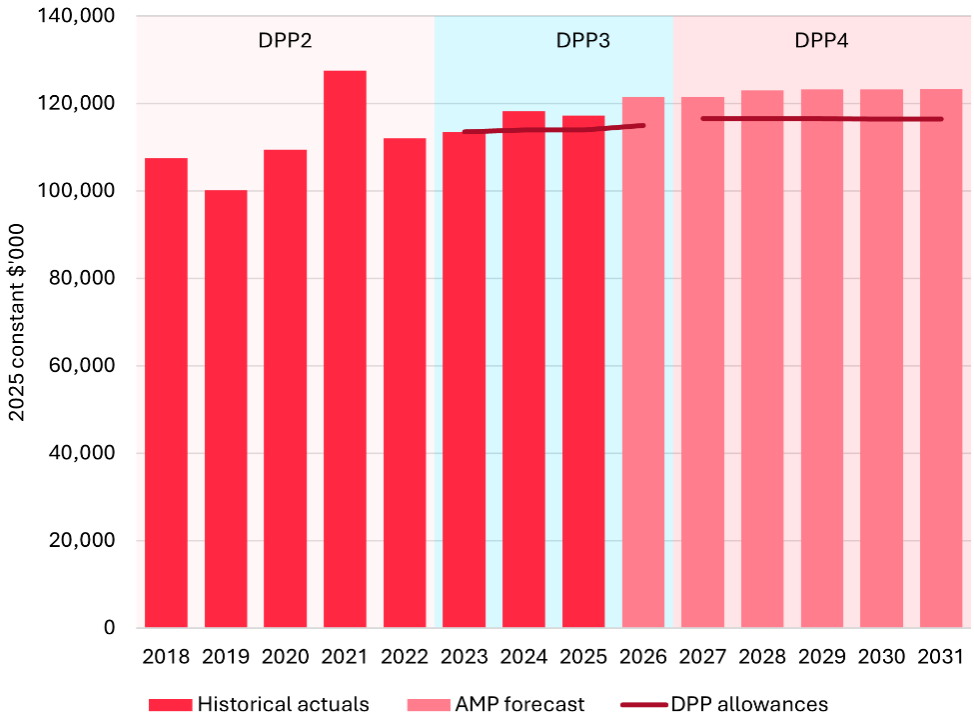
3.18 The opex allowances that we have set for the GPBs over DPP4 are set out in Table 3.4. They amount to between 87% and 97% of GPBs' AMP forecasts. The results of our BST approach were lower than AMP opex forecasts for all years for all GPBs.

Table 3.4 Operating expenditure allowances (constant 2025 $ 000)

GPB	GPB AMP forecast	DPP4 allowance	Allowance as a % of AMP forecast
Firstgas Transmission	326,267	316,860	97%
Firstgas Distribution	68,530	59,826	87%
GasNet	13,558	12,460	92%
Powerco	104,892	99,372	95%
Vector	101,012	94,026	93%
Industry total	**614,259**	**582,543**	**95%**

3.19 Figure 3.3 shows the aggregate opex profile over all GPBs.

Figure 3.3 Comparison of industry total actual opex, AMP opex forecast and DPP allowances (constant 2025 $'000)



3.20 Our final decisions on opex for DPP4 make a number of changes from DPP3 to better reflect the likely opex needs, rising cost of services and increasing use of opex as a substitute for capex planned by GPBs over the DPP4 period.

Base opex is set from 2025 data with adjustments and includes allowances for renewable gas blending activities

3.21 The base year sets the starting point of BST modelling used in setting opex allowances. We have set the base year as 2025, being the latest disclosure year for which ID opex data is available. We signalled the update from the 2024 base year in our draft decision.

3.22 We have made base year adjustments related to costs and savings that we have identified as being non-recurring and therefore not appropriate to carry forward under the BST approach.

3.23 Within the base year adjustments, we have maintained the DPP3 allowance amounts for blended gas investigations for Firstgas Transmission, Firstgas Distribution and Powerco who are likely to incur blended gas investigations expenditure based on more clearly substantiated programmes of work.

3.24 We have not provided for a separate specific innovation allowance as we have for the price-regulated electricity distributors. We consider the broader regime continues to provide incentives for GPBs to innovate to find efficiencies or deliver additional services which consumers value. For example, the allowances in DPP4 for blended gas investigation support, in a scrutinised and targeted way, the main area of innovation identified by GPBs.

We have considered the prudency and efficiency of step changes guided by five factors

3.25 We have amended our approach from that used in DPP3 to assess potential opex step changes by using a set of factors. The step change factors help inform our judgement of where a proposed step change is likely to be prudent and efficient. These factors are not a check box exercise. We have applied discretion on whether or not the application of every factor in the assessment of a step change is appropriate on a case-by-case basis. The factors are:

3.25.1 significance;

3.25.2 adequately justified with reasonable evidence;

3.25.3 not captured in other components of DPP allowances;

3.25.4 a driver outside the control of a prudent and efficient supplier; and

3.25.5 widely applicable.

3.26 Table 3.5 summarises the opex step changes provided for in our final decision. There are no step changes for GasNet, which did not seek any.

Table 3.5 Summary table showing approved step changes by GPB

Step	Firstgas Transmission	Firstgas Distribution	Powerco	Vector
Capex-opex trade-off	✓			✓
Cybersecurity	✓	✓		✓
Software-as-a-service (SaaS)	✓	✓		✓
Renewable gas			✓	
Station and compressor decommissioning	✓			

3.27 Our final decision is to provide an opex step change for capex-opex trade-off where we are satisfied of a data-driven, condition-based risk management approach that will avoid, or at least defer, capital intensive renewals. We have also considered whether there is an offsetting reduction in AMP forecasts for relevant capex categories, which we observed for Firstgas Transmission and Vector. Both entities have identified a range of specific capex-opex trade-offs which result in a material decline in the level of ARR capex forecasted.

3.28 We recognise that the relationship between opex and measurable reduction in capex arising from substitution can be complex, non-linear, and subject to timing differences between when opex costs are incurred and when potential capex savings will materialise.

3.29 We have not provided step changes for Powerco or Firstgas Distribution as we have not observed a decrease in forecast ARR capex when compared with historical averages and consider there is a risk that this would be included elsewhere in capex allowances. As such we were not satisfied that a step change would be prudent and efficient.

3.30 We have provided Firstgas Transmission with a step change for specified station and compressor decommissioning costs. This follows our consideration of evidence put forward by Firstgas in its submission on our draft decision which previously declined this step change.[73]

3.31 In this particular case, we are satisfied that the specific, identified work is sufficiently justified, likely to be prudent and efficient, incurred to reduce lifecycle costs and likely to be in the long-term benefit of consumers.[74]

3.32 We have also approved the following opex step changes:

3.32.1 cybersecurity full amounts sought by Vector and Firstgas Transmission and Distribution. For Firstgas Transmission this is an increase, after considering its submission and supporting information on our draft decision for a partial approval;

3.32.2 SaaS for Firstgas Transmission and Distribution, and Vector. Based on our assessment of submissions on our draft decision, we have increased the amount provided here for Firstgas, and retained the cap on costs sought by Vector; and

3.32.3 a partial step change for Powerco related to renewable gas expenditure. Powerco has evidenced a likely programme of work related to connection of renewable gas facilities.[75]

3.33 We have declined other step changes requested by GPBs where we considered these would not be in the long-term benefit of consumers, using the factors as a guide to inform our judgement.

Opex trends are driven by forecast ICP growth and input cost inflation forecasts

3.34 Our forecast of opex trends has three components: cost changes driven by forecast changes in scale, input price inflation, and productivity. We aim to forecast opex trends over the DPP4 period based on estimation of expected changes in these factors and in a way which incentivises efficiency.

[73] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), pp. 26-30.
[74] Our final decision on the related larger question of decommissioning costs is to defer this issue, with wider work required on legal responsibilities to undertake work (Future Issue decision F2).
[75] This is in addition to the amount for investigating alternative gases that we have allowed to remain in Powerco's base year opex, and to therefore be carried forward into DPP4. We have likewise allowed for these costs to be carried forward in the base year opex for Firstgas Distribution, but not for Vector or GasNet. See Attachment C for more discussion.

3.35 In general, we expect the cost to maintain and operate a network to have a relationship with its size for GDBs. We allow opex to vary with forecast changes in network size. For the GTB, given its different operating model, we do not apply any scaling to opex, consistent with recent resets.

3.36 As in previous resets, for GDBs we apply an elasticity-based model that estimates the relationship between opex and two key network size drivers.[76] The model combines ICP count and network length(km) into a single composite scale variable and estimates an elasticity value for this variable using updated historical data. For DPP4, the estimated elasticity is 0.44, indicating that opex has historically changed proportionally less than overall network scale.

3.37 We scaled adjusted base year opex using this elasticity, GDBs' forecast changes in ICPs and - because GDBs do not forecast network length - the associated changes in network length implied by those ICP forecasts and historical relationships between network length and ICPs.

3.38 All GDBs are forecasting declining ICP counts, whereas the model is calibrated on periods without such decline and there is limited evidence on how opex responds in a contracting network. To address this, we have made two adjustments.

3.38.1 First, we applied a floor to forecast network length. Where ICPs are forecast to decline, network length is assumed to remain constant (rather than decrease) for the purpose of scaling opex. This reflects that reductions in ICPs may not lead to near-term reductions in physical network size, particularly where disconnections are gradual and uncoordinated.

3.38.2 Second, we down-weighted the overall scaling effect when it implies a reduction in opex due to forecast declines in ICP counts. In these circumstances, only 25% of the modelled reduction in opex is applied. This recognises that a large proportion of opex is fixed and may not decline as ICPs decrease, and that alternative cost drivers may also emerge, but that we still expected GPBs to seek efficiency savings.

3.39 Applying this approach results in a small negative scaling effect, with annual opex reductions across GDBs ranging from (0.03%) to (0.27%) per annum.

3.40 Cost escalator forecasts need to account for forecast cost changes relative to overall inflation or 'real price effects'. Our decision is to retain the approach proposed at our draft decision of forecasting cost escalation using the latest available forecasts of the all-industries labour cost (60% weighting) and producers price indices (40% weighting), with no adjustment, and to apply the same cost escalator to all opex costs.

3.41 We have retained our draft decision to apply an opex partial productivity factor (PPF) of 0%. This decision draws on recent trends in measured productivity, consideration of the prospect of opex-capex substitution and the wider context of a declining gas market.

[76] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para A156.

Adopting economic asset lives mitigates demand risk and supports GPBs' ongoing incentives to invest

3.42 Our final decision is to specify new asset adjustment factors to shorten regulatory depreciation lives for all GPBs in DPP4 to mitigate risks of network stranding due to the expected long-term decline in demand for natural gas. This completes the overall transition to more realistic economic lives we began in DPP3.

3.43 Shortening asset lives increases forecast depreciation, the total revenues allowed in DPP4, and therefore the expected impact on consumer bills. However, we consider that continuing to adopt more realistic economic asset lives during DPP4 best promotes the long-term benefit of consumers. Importantly, it supports incentives for GPBs to keep investing efficiently by increasing confidence that total network costs can be recovered over pipeline lifetimes. This helps mitigate stranding risk and supports safe and reliable network operations as well as the continued provision of GPSs to meet the needs of current and future consumers. Not completing the transition in DPP4 (deferring it to a later time) would result in higher costs falling on a smaller consumer base in the future and likely higher risks of early network shut downs.

3.44 To estimate the extent of asset life adjustment for each GPB, we have decided to reapply the network stranding model we used for DPP3, retaining the same long-term industry wind-down scenarios and weightings that we previously assessed as plausible central scenarios (2050 and 2060 wind-down dates with 33:67 relative weightings). We have also updated the model's long-term cost variables and assumptions for DPP4 to reflect the latest data available (eg, regulated asset values, cost of capital, forecasts of near-term demand, and opex and capex allowances).

3.45 Our final decision for DPP4 is to shorten existing asset lives by applying the asset life adjustment factors produced by the network stranding model in Table 3.6. This increases DPP4 forecast depreciation for the sector by $245.6m relative to unadjusted allowances.[77] This is $2.5m lower than our draft decision, reflecting updates to model inputs and a correction to capture depreciation for DY25 commissioned assets.

[77] Shortening asset lives increases building block costs within a DPP period because it raises the depreciation (or 'return of capital') allowance (see Attachment A). Depreciation is the mechanism by which GPBs recover their capital investments over the life of assets. Under a straight-line method of regulatory depreciation, shortening asset lives reduces the recovery period and increases annual depreciation amounts, mitigating the risk that some capital costs might not be recovered with declining demand.

Table 3.6 DPP4 network stranding mitigation – final decision ($m, nominal BBAR)

GPB	Asset life adjustment factor	Forecast DPP4 depreciation allowance before adjustment	Forecast DPP4 depreciation allowance after adjustment	Additional forecast depreciation in DPP4
Firstgas Transmission	0.73	320.2	441.4	121.2
Firstgas Distribution	0.70	65.1	93.5	28.4
GasNet	0.57	6.9	12.1	5.2
Powerco	0.68	125.1	185.2	60.1
Vector	0.81	133.0	163.6	30.6
Industry total		**650.2**	**859.8**	**245.6**

Network stranding risk in DPP4 continues to threaten the long-term benefit of consumers

3.46 The context for this decision is that long-term declining natural gas use creates a risk that GPBs may no longer expect to generate sufficient revenues from customers over time to recover efficient costs and make normal profits. If this risk of 'economic network stranding' is not addressed, GPBs may curtail network investment or make other sub-optimal decisions to the long-term detriment of consumers.

3.47 When we considered this issue for DPP3 we made the decision to shorten network asset lives for regulatory depreciation purposes to better align them with more realistic economic asset lives. This brought forward some allowed revenues for GPBs into DPP3, mitigating stranding risk and supporting investment incentives.

3.48 Our DPP3 decision assumed that the transition to shorter asset lives to mitigate stranding risk would occur over two regulatory periods, with approximately half of the transition occurring in DPP3. We said we expected to complete the transition to economic asset lives during DPP4, by further shortening regulatory lives, subject to a fresh assessment of risk at that time.[78]

3.49 During our DPP4 reset process, we heard from stakeholders about how the extent of long-term network stranding risk for GPBs may now differ to that we modelled at DPP3. We outline how we took that feedback into account in Attachment D.

Long-term scenario modelling has informed our assessment

3.50 Since there is no definitive source of information that narrows the wide range of possible profiles of declining long-term demand, we had regard to a range of factors that influence long-term prospects for reticulated gas networks, and high-level modelling of industry 'wind-down' scenarios to estimate stranding risk in DPP4.

[78] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 6.30.2.

3.51 In summary, we have concluded that although some sources of network stranding risk have evolved since the DPP3 reset, the two modelled industry scenarios we used for DPP3 remain central in the likely distribution of long-term risk and are plausible and reasonable scenarios to reapply in the DPP4 context:[79]

3.51.1 domestic gas production and estimated reserves are declining more quickly than previously expected, including in the period since our DPP4 draft decision. This factor weighs somewhat more strongly in our assessment. However, in our view the modelled 2050 wind-down scenario remains suitably aggressive to capture the impact of the evolving risk associated with accelerating declines in usage and the possibility of an early industry shutdown due to constrained supply-side conditions;

3.51.2 government policy toward gas exploration has changed since DPP3, and future imports of gas are being considered, offsetting to some degree the faster decline in current domestic gas reserves. On balance, and consistent with our view in our DPP4 draft decision, these developments have not materially changed our assessment of network stranding risk for DPP4, particularly as policy changes can take some time to translate to physical changes in gas supplies; and

3.51.3 the prospect of some material level of reticulated gas use continuing beyond the 2050 net zero carbon emissions target was a primary reason for introducing our 2060 wind-down scenario in our DPP3 decision, and weighting it more heavily than the 2050 wind-down scenario.[80] We consider the possibility of longer-term future use of gas pipelines, including at reduced network scale, remains adequately recognised by retaining the 2060 wind-down scenario in our stranding model for DPP4.

3.52 Our conclusion was that we should reapply the two scenarios, together with the 33:67 weightings, from DPP3 after updating for the most recent building block cost estimates. We considered the concerns expressed by some consumers over high energy and input costs, against the risk of adverse longer-term consequences for consumers of delaying mitigation action and concluded that no further changes in settings were required.[81]

3.53 Taking the outputs from the modelling into account, we assessed that a material unmitigated risk of network stranding exists in DPP4, and we should complete the transition to economic asset lives to support continued incentives for GPBs to invest. The specific ways that this benefits gas consumers in the long-term are set out below.

[79] Consistent with our high level approach and the extent of uncertainty, we use "central" broadly, to indicate a middle position in a range, not the mean or median of a distribution in the precise statistical sense: see HoustonKemp "Form of control for gas distribution businesses in New Zealand (Report for Vector)" (20 January 2026), p. 4-5.

[80] Another reason was to acknowledge that a longer wind-down scenario could be seen as a possible proxy for an earlier wind-down scenario with some residual network value that gas pipeline consumers should not be paying for through network charges. See Attachment D.

[81] Delaying mitigation action means remaining costs would fall on a smaller future customer base who are assumed to have less willingness and capacity to pay for required network charges. This would likely increase the prospect of under-recoveries for GPBs and threaten ongoing incentives to invest.

Completing the transition is in the long-term interests of consumers

3.54 Applying the asset life adjustment factors in Table 3.6 above in DPP4 to shorten asset lives and complete the transition to more realistic economic lifetimes promotes the long-term benefit of consumers of gas pipeline services as it:

3.54.1 promotes incentives for GPBs to continue investing, making it more likely that gas networks will remain available to satisfy consumer demand for the period over which gas is used, at the quality demanded by consumers; and

3.54.2 is net present value (NPV)-neutral (with respect to GPBs' cost of capital) so limits the possibility of GPBs making excessive profits and does not commit gas users in aggregate to paying more for pipeline use over assumed lifetimes of the networks.

3.55 Given that overall gas pipeline usage has peaked ahead of DPP4, and is now forecast by all GPB networks to fall, we consider it important to make these adjustments while the customer base is at its broadest. This reduces the risk of escalating prices for future gas consumers as New Zealand moves further towards decarbonisation.[82]

Our decision is compatible with the evolving risk profile at this time

3.56 We emphasise that our final decision involves a high-level judgement based on a range of information and the outputs from our simplified modelling, which we consider to be consistent with the nature of the risks faced by the gas sector. Our modelling is not intended to be predictive of eventual industry end-states, but is a tool allowing us to assess actions that can be taken at DPP4 to promote the long-term benefit of consumers under a range of plausible outcomes and conditions of high uncertainty.

3.57 Although we consider our DPP4 decision is compatible with the evolving risk profile at this time, relevant factors and sources of risk will continue to develop. Future DPP resets provide an opportunity for us to act on new information if required, eg, by shortening or lengthening asset lives to reflect future levels of stranding mitigation.

3.58 GPBs should also face strong incentives during DPP4 to adapt their own business practices to mitigate or manage residual risk of declining demand. This will likely benefit consumers over the long-term, eg, net cost reductions and efficiencies. We observed some changes being made by GPBs to the way they plan, operate and invest during DPP3, and we will continue to monitor GPBs' actions ahead of the next reset.[83]

[82] In their submissions on our draft decision, MGUG and Greymouth Gas expressed some concerns with our approach to asset life shortening, including the intertemporal impacts: MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026); Greymouth Gas "Re: Gas DPP4 2026 – Draft Decision" (22 January 2026), p. 3. We acknowledge that our decision places weight on the expected future benefit to future consumers as a whole, which we consider outweighs the risks from increased prices faced by current consumers.

[83] Initiatives include changes in asset management planning and investment or operational decision-making, progress in blending and injecting renewable gases, review and adjustment of policies on capital contributions, system growth and disconnections, and understanding and representing risk across network geographies, and assessment of possibilities for network 'rightsizing'.

The return on capital has increased modestly

3.59 Our building blocks model includes a return on capital, being the weighted average cost of capital (WACC) multiplied by the value of the RAB. The value of the WACC can have a large impact on the revenue allowances we set, as it determines the return a GPB is allowed on both its existing RAB and its forecast capex over the regulatory period.

3.60 We estimate the WACC separately to the DPP process following a methodology specified in the WACC IMs.[84]

3.61 For our final DPP4 decision, we have used the mid-point vanilla WACC estimate of 6.64%. This is a 0.50% increase from the WACC estimate we used in DPP3, which was 6.14%. It is an increase of 0.05% from 6.59% in our draft decision. Refer to Attachment G for more details.

High Court judgement in relation to the WACC percentile

3.62 On 7 May 2026, the High Court issued its judgement on First Gas Limited's appeal against our Gas Transmission Services and Gas Distribution Services IMs determined following the 2023 IM Review.[85] The judgement considers whether an alternative input methodology that applies a 65th or 67th percentile estimate of WACC would be materially better than the 2023 IMs which apply the mid-point (50th percentile) estimate.

3.63 The Court concluded that the 65th percentile estimate was materially better than the mid-point estimate, in terms of the purpose of IMs under s 52R of the Act.[86] As at the date of our DPP4 decision, the Court has not made orders giving effect to the judgement, although these are expected to follow.

3.64 In accordance with the current Gas IMs, we have applied the mid-point estimate of WACC in our DPP4 decision. However, we anticipate we may need to reset DPP4 in future to account for the change in the WACC estimate, in accordance with any orders given by the Court. This is consistent with s 53ZB of the Act which provides that we must reset a DPP if an IM changes as a result of a merits appeal, resulting in a materially different path being set.

3.65 We will notify stakeholders through the usual channels, including our website, regarding any next steps following Court orders.

We have shaped GDBs' revenue paths taking into account an expected decline in consumption over DPP4

3.66 Under the WAPC, we shape each GDB's allowed revenue path using forecast demand to maintain constant weighted average prices in real terms over the regulatory period.

[84] Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27, Part 4, subpart 4, and Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, Part 4,subpart 4.
[85] First Gas Ltd v Commerce Commission [2026] NZHC 1224.
[86] Section 52R of the Act provides that the purpose of input methodologies is to promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation, or proposed regulation, of goods or services under this Part.

3.67 We implement this through a CPRG factor, derived from forecasts of number of connected consumers and gas quantities and the mix of actual fixed and variable revenues. Taking account of the forecast decline in connections and volumes, we set a starting price allowance that effectively provides constant real prices to consumers.

3.68 Revenue shaping by CPRG is NPV-neutral. It affects the timing of revenue recovery across the period but does not change the total revenue that GDBs are allowed to recover on an NPV basis.

3.69 We have used GDBs' own demand forecasts to determine the CPRG factors, consistent with our approach in DPP3. We engaged Concept Consulting to independently review those forecasts and are satisfied they are reasonable for the purpose of setting the revenue paths.

3.70 As demand is forecast to decline over DPP4, the CPRG factors are negative for all GDBs. As a result, allowed real revenue is forecast to decline over the regulatory period, and allowed revenue in the first year is higher than it would be under flat or growing demand.

Setting rates of change for the GPBs

The default rate of change is zero

3.71 Under the Act, we must set a rate of change for the GPBs. This rate of change must be 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. We refer to this rate of change in productivity as the 'X-factor'. Our decision is to set a default rate of change relative to CPI (X-factor) of 0%.

3.72 As detailed below, our final decision is to apply the default rate of change of 0% for all GPBs except Vector, for which we have set a starting price and alternative X-factors to smooth real prices by 10.0% for each of the first 3 years of the DPP4 period.

We have considered alternative X-factors to smooth price impacts

3.73 We may set an alternative rate of change for a particular GPB, as an alternative in whole or in part, to the starting prices (under s 53P(3)(b) of the Act), if this is necessary or desirable to:

3.73.1 minimise any undue financial hardship to the GPB;

3.73.2 minimise price shocks to consumers; or

3.73.3 create an incentive (under s 53M(2)) for a GPB to improve its quality of supply.

3.74 Having completed our assessment of the GPBs' current and projected profitability, we have considered whether an alternative rate of change for each GPB is necessary. To do so we have assessed whether the starting price adjustment implied by our assessment of the GPBs' current and projected profitability might result in price shocks for consumers.

3.75 Table 3.7 below shows the implied starting prices for each GPB if we were to apply a one-off starting price adjustment and a 0% X-factor, ie no annual real price increase for the remaining years of DPP4.

3.76 As an update to our draft decision, these estimates now take into account updated estimates for actual revenues in the last year of DPP3 (2025/2026). With declining actual revenues and volumes, compared to forecasts, for GasNet, Powerco and Vector, the implied real price increases here are higher than in our draft decision.

Table 3.7 Implied real price increases for a one-off starting price adjustment ($ million nominal)

GDB	Implied starting price ($ million)	Implied real price increase for year 1 of DPP4
Firstgas Transmission	222.1	5.9%
Firstgas Distribution	44.4	2.4%
GasNet	6.7	10.4%
Powerco	80.9	7.8%
Vector	80.0	25.4%

3.77 For Firstgas Transmission, Firstgas Distribution and Powerco, the transition to DPP4 does not result in a step change large enough to consider additional smoothing, which would cause a departure from our preference for flat real prices. For these GPBs we have applied the default rate of change without adjustment.

3.78 For GasNet, the implied starting price increase is 10.4%, due in part to demand in DPP3 being lower than forecast. We considered applying an alternative rate of change for GasNet, and decided not to. The implied starting price adjustment here is only marginally above the level at which we consider smoothing prices. Our decision reflects a judgement and preference for flat real prices within the period.

3.79 The implied starting price increase for Vector is 25.4%. Vector's price path under DPP3 remained relatively flat, reflecting both cost reductions implemented at that reset and the decision not to apply an X-factor over the last 3 years of DPP3. As a result, its end-of-period prices are lower relative to the starting point implied by DPP4 allowable revenues. This results in a larger implied step-up in prices for Vector consumers at the beginning of DPP4, notwithstanding reductions in forecast capital expenditure.

We have smoothed Vector's price path over the first three years

3.80 We have considered the impacts of the price shock posed to Vector's consumers from a 25.4% starting price increase. This reflects, in part, that actual demand during DPP3 was lower than forecast. It also reflects the profile of Vector's DPP3 price path, where real price increases were front-loaded and then held flat in real terms, resulting in a lower level of revenue in the final year of DPP3 than would have occurred under a more evenly smoothed profile. Together, these factors result in a larger implied price step between the last year of DPP3 and the first year of DPP4.

3.81 In reaching our decision, we considered the following options, set out in Table 3.8:

3.81.1 No smoothing – allowing the full 25.4% price step between DPP3 and DPP4;

3.81.2 Uniform smoothing – entirely smooth the revenue path so that the initial price step matches the average year-on-year real growth rate, at 8.0% (real);

3.81.3 2-year smoothing – a combination of 13.5% (real) steps in both of first two years, followed by 0% real price growth rate for the remaining three years; and

3.81.4 3-year smoothing – a combination of 10.0% (real) steps in each of the first three years, followed by 0% real price growth rate for the remaining two years.

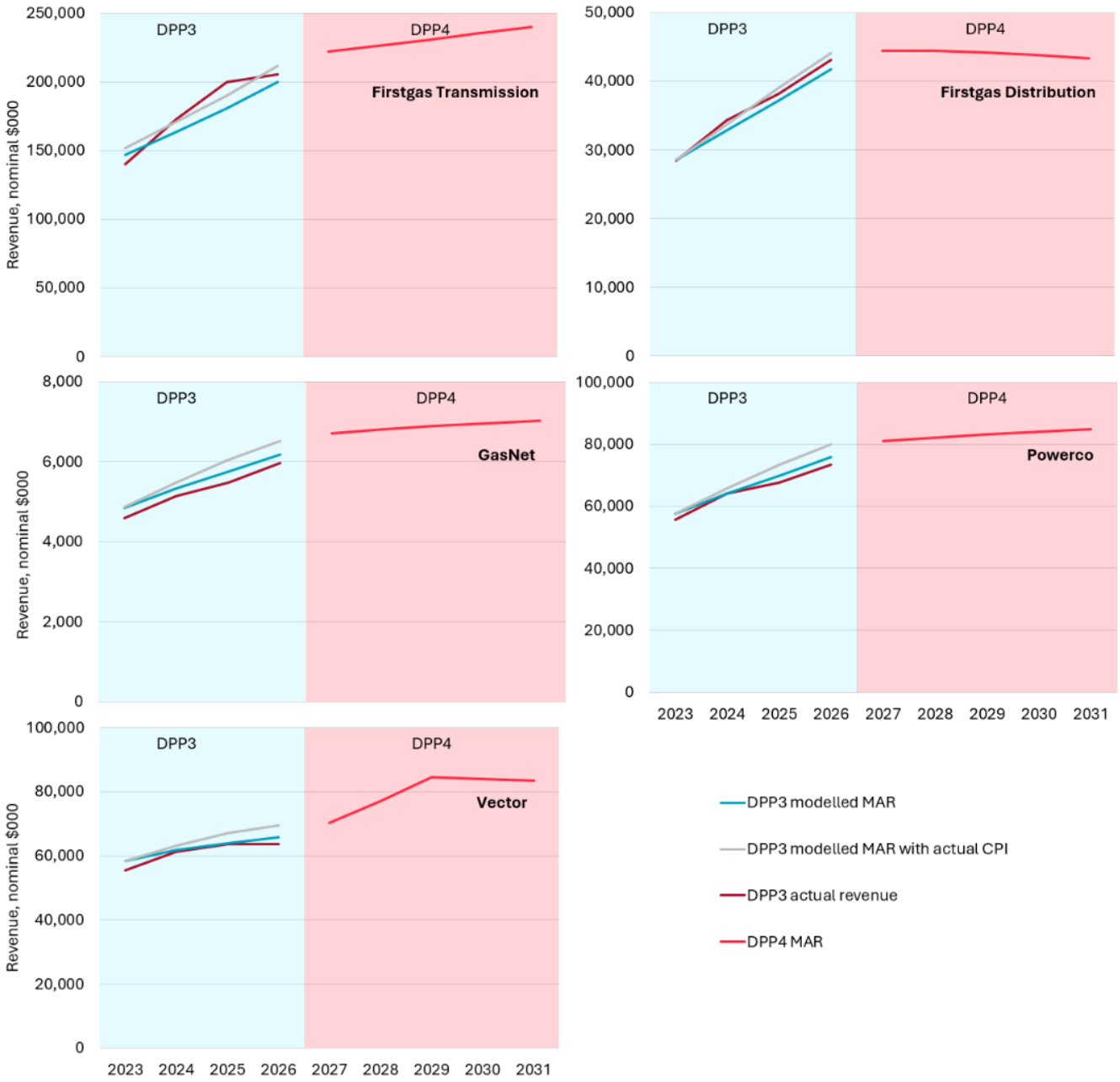
Table 3.8 Revenue smoothing options we considered for Vector

Revenue smoothing Option	Initial year price change	Subsequent year price change
No smoothing	CPI + 25.4%	CPI + 0%
Uniform smoothing	CPI + 8.0%	CPI + 8.0%
2-year smoothing	CPI + 13.4%	CPI +13.4% for year 2, then CPI + 0%
3-year smoothing	CPI + 10.0%	CPI +10.0% for years 2 and 3, then CPI + 0%

3.82 We have decided that the '3-year smoothing' approach is in the best interests of consumers. This option limits the maximum annual real increase to 10% and - by setting flat real prices in the last two years - reduces the departure in those years of the shaped price path from the unshaped MAR profile.

3.83 Figure 3.4 below shows the resulting MAR profiles we have set for DPP4. It also shows DPP3 revenue profiles for the as-set MAR profile (light blue), how this was updated for outturn CPI (grey) and the actual revenue profiles reported by GPBs (maroon).

Figure 3.4 Shaped MAR profiles for DPP4 and revenue profiles from DPP3 (nominal $000)



Consumer bill impacts

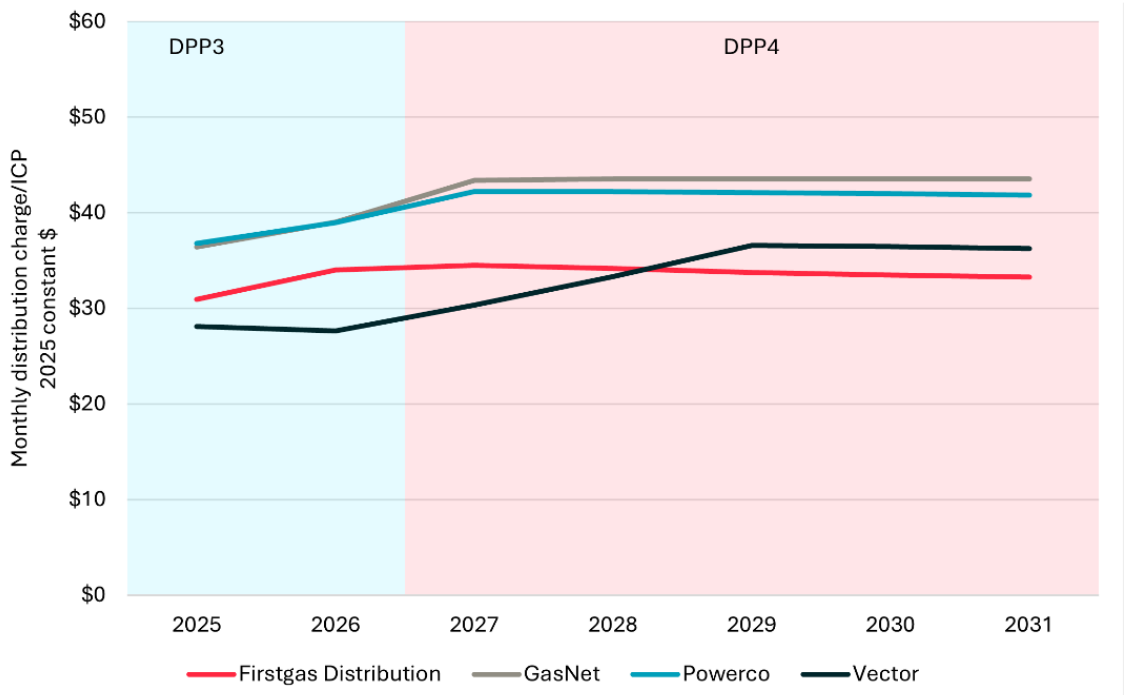
The GDB revenue paths equate to moderate bill impacts for residential and small commercial users

3.84 Transmission and distribution charges together make up around one-third of residential and small commercial gas bills. On this basis, and assuming no change in other bill components, we have estimated the impact of our decision on consumer gas bills. This is a useful summary measure. We recognise that the impact on individual consumers, as well as large commercial and major industrial users, will vary from this, depending on circumstances and contractual terms with GPBs and retailers.

3.85 As shown in Figure 3.5, the estimated average monthly distribution network charges for residential users over DPP4 are largely flat in real terms, other than the initial step and the smoothed three year step up for Vector consumers. The indicative charges in this figure reflect the local GDB pipeline charge. We have estimated this using an allocated share of each GDB's overall DPP4 revenue profile based on its current split of revenues by consumer segment, divided by the forecast number of residential users.

3.86 We note that Figure 3.5 shows that our estimated increase in distribution charges for Vector's residential consumers is off the lowest level in 2026 and leaves it close to the cheapest pricing over DPP4 as a whole.

Figure 3.5 Estimated average monthly residential distribution charges over DPP4, including distribution (constant 2025 $ per ICP)



3.87 We then estimate the impact on residential gas bills of these distribution changes, plus an equal allocation of the 15% of transmission revenues met by residential users.[87] We find that the impact on the gas bill for an average residential user will be an increase in real terms (ie, excluding inflation) of:

3.87.1 between about 1% and 3% in the first year of DPP4, followed by flat real prices, for consumers on the Firstgas Distribution, GasNet and Powerco networks; and

3.87.2 about 3% in each of the first three years followed by two years of flat real prices, for consumers on Vector's network.

3.88 Analysis of information disclosure (ID) data indicates that average effective price changes for standard commercial consumers over the two years following the DPP3 reset were generally in line with those for residential consumers across all GDBs. On this basis, we expect that the total bill impacts of our decision for standard commercial users will be similar (in percentage terms) to the residential bill impacts described in the previous paragraph.

Targeted measures to manage demand volatility

3.89 We have implemented targeted measures to manage demand volatility and reduce the risk of sharp price changes for both GDBs and the GTB.

Hybrid mechanism to address in-period demand shocks

3.90 We have implemented the hybrid demand variation revenue adjustment mechanism recently included in the GDB IMs to provide a limited 'release valve' to address significant in-period demand shocks. This mechanism is not intended to address routine forecasting error or normal demand variation, which GDBs continue to bear and manage under the WAPC.

3.91 This is a change from our draft decision, following our separate consultation to amend the GDB IMs to include this mechanism.[88]

Implementation in DPP4

3.92 Consistent with the recent IM amendment, we have implemented the hybrid mechanism in the GDB DPP4 determination, by:

3.92.1 specifying how the demand variation revenue adjustment is calculated from forecast and actual revenues;[89]

3.92.2 applying a symmetric ±15% threshold around forecast revenue, beyond which the mechanism applies symmetrically to positive and negative deviations; and

[87] Concept Consulting for Commerce Commission, "Gas Demand projections to feed into the DPP regulation of GDBs" (22 August 2025)
[88] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).
[89] With forecast revenues including an adjustment for outturn inflation.

3.92.3 sharing only the portion of any deviation of actual revenues outside the threshold on a 50/50 basis between the GDB and consumers.[90]

Rationale for change from draft decision

3.93 In our draft DPP4 decision, we decided not to introduce a mechanism to address in-period demand shocks. We received mixed submissions with a majority opposing this decision, arguing that increasing uncertainty in the gas sector, and the potential for material and abrupt demand shocks, meant existing tools under a WAPC may not adequately manage demand risk within a regulatory period.[91]

3.94 We undertook a further targeted consultation to introduce a hybrid mechanism through amendments to the GDB IMs and GDB DPP4 Determination. Following consideration of submissions on that consultation, we have amended the GDB IMs to include a hybrid price path mechanism through the demand variation revenue adjustment mechanism in the GDB DPP regime, with its specification to be set in the GDB DPP determination at each DPP reset.[92]

3.95 Our final decision for DPP4 is to implement the hybrid mechanism as specified with the parameters above in paragraph 3.128. These are the same parameters as in our targeted consultation draft decision.[93]

3.96 Submissions on that consultation reflected two broad positions. GDBs supported the introduction of a mechanism and generally sought a lower threshold with the intention that it apply to demand forecast uncertainties.[94] Greymouth Gas, the Major Gas Users Group and Fonterra opposed the mechanism, arguing that all demand risk appropriately sits with GDBs under a WAPC, even in a declining market.[95]

[90] As set out in the GDB IMs, any such adjustment is applied through a recoverable cost that flows into future price setting.
[91] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026), pp. 14-16.
[92] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).
[93] Commerce Commission, "Revised Draft GDB DPP Determination – Changes related to proposed amendments to IMs – Draft reasons paper" (2 April 2026)
[94] Firstgas, Powerco and Vector "Gas DPP4 2026 - Submission on hybrid mechanism and IM amendments" (21 April 2026); and separate individual submissions from these GPBs: Vector, Powerco, Firstgas
[95] MGUG "Re: Revised Draft GDB Default Price-Quality Path Determination" (21 April 2026); Fonterra "Submission – Draft decisions – Gas DPP4" (21 April 2026); Greymouth Gas "Re: Gas DPP4 2026 - Hybrid mechanism and IM amendments" (21 April 2026); Greymouth Gas "Re: Gas DPP4 2026 - Hybrid mechanism and IM amendments (cross-submission" (29 April 2026)

3.97 Our implementation of the hybrid mechanism for DPP4 is intended to address large demand shocks, not forecast uncertainty, recognising that there are limits to the ability of GDBs to manage the risks of truly large demand shocks. As set out in our final decision, large and unforeseen demand shocks could exceed what GDBs are reasonably able to manage under existing arrangements, and give rise to consumer harm. The hybrid mechanism will provide a proportionate and limited intervention to mitigate these events as well as enhancing, to a degree, certainty about allocating the costs and risks associated with demand shocks.[96]

3.98 Further detail on our reasoning is set out in the GDB IM amendments final decision reasons paper and GDB IM amendment determination.[97, 98] Attachment A provides additional discussion on the implementation of the parameters applied for this reset.

GTB price path implementation for DPP4

3.99 The GTB operates under a revenue cap. For DPP4 the GTB revenue cap framework is carried forward from DPP3, updated to give effect to the 2023 IM review wash-up changes. We have included some revenue cap features from the EDB determination, adapted to the GTB context.

3.100 In particular, we have implemented new price path features required by the amended GTB Input Methodologies (GTB IMs) that are intended to better manage volatility in revenues and prices both within and between regulatory periods.[99, 100] These include the following features, largely mirroring those applied in EBD DPP4:

3.100.1 replacing the former demand-based cap on annual revenue increases with a revenue smoothing limit;

3.100.2 incorporating a voluntary undercharging limit, and

3.100.3 specifying how wash-up balances are to be drawn down over time.

3.101 We have set the revenue smoothing limit at 10% above the CPI-X rate of change. This caps the extent to which forecast net allowable revenue and recoverable costs (including wash-up drawdown amounts) can increase allowable revenues in any one year. It applies to the recovery of ex post wash-up amounts during the regulatory period, rather than to the initial ex ante price path setting.

[96] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026), p. 4-5.
[97] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).
[98] Gas Distribution Services Input Methodologies Amendment Determination (No.1) 2026 [2026] NZCC 17
[99] Commerce Commission "Amendments to input methodologies for Gas Transmission Services – Amendments related to the 2026 default price-quality path – Final decision reasons paper" (26 May 2026).
[100] Gas Transmission Services Input Methodologies Amendment Determination (No.1) 2026 [2026] NZCC 18

3.102 The key aim of these changes is to reduce in-period and inter-period price volatility and the risk of price shocks to consumers, while preserving present value neutrality for suppliers. Where the limit binds, unrecovered amounts are deferred and rolled forward through the wash-up account with a time-value-of-money adjustment. This ensures that prices better reflect the costs of providing GTB services over time, while promoting the long-term benefit of consumers under s 52A.

3.103 Overall, adopting these price path implementation details improves consistency with the EDB regime, strengthens protections against sharp price movements following demand or revenue shocks, and provides clearer, more predictable pricing outcomes for GTB consumers in DPP4. See Attachment A for further discussion.

We are retaining the DPP3 quality standards

3.104 Our final decision is to retain the current quality standards that apply to the GPBs. This is the same as our draft decision. These standards are:

3.104.1 for the GTB and GDBs, the time taken to respond to any emergency must be less than 180 minutes;

3.104.2 for the GTB and GDBs, the percentage of emergency responses taking longer than 60 minutes must not be greater than 20%;

3.104.3 the number of major interruptions for the GTB must not exceed zero; and

3.104.4 if there is a major interruption, that the GTB must provide a detailed publicly available report.

3.105 We investigated introducing additional quality standards but were not convinced that these were necessary at this time. In reaching our final decision, our reasons for not making a change to the current gas quality settings include:

3.105.1 gas sector quality outcomes have been relatively stable;

3.105.2 there are other regulatory measures and commercial incentives driving gas sector quality outcomes;

3.105.3 stakeholder feedback to our issues paper did not identify that a change was supported; and

3.105.4 our analysis indicates that the current quality standards are fit for purpose.

3.106 Stakeholder feedback on our draft decision did not identify that a change to existing quality standards was necessary. While some broader issues were raised, such as disconnections and network rightsizing, these are not readily addressed through current quality metrics and are better considered through future work (see below).

3.107 Over the DPP4 period we will continue to monitor key quality metrics disclosed through ID, such as GDB customer average interruption duration index (CAIDI) performance, which may provide insight into potential unreliability in uneconomic parts of networks, and GTB gas leaks. This ongoing monitoring will inform whether additional quality standards are necessary in DPP5.

3.108 See Attachment E to this paper for more discussion of quality standards.

Future issues not affecting our DPP4 final decisions

3.109 We have considered several other issues raised by submitters during our DPP4 consultation process which have not affected our final decisions for DPP4 but could play a role in the development of regulatory policy for future PQ paths or other Part 4 regulation.

3.110 Table 3.9 below sets out these issues and our views. See Attachment F to this paper for further discussion.

Table 3.9 Future issues not affecting our DPP4 final decisions

Issue	Our view
Regulatory treatment of network rightsizing **(Decision F1)**	We understand that plans for network rightsizing by GPBs are still in their formative stages and are unlikely to materially affect DPP4. Any regulatory response could be coordinated as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest). A key future potential concern is the withdrawal of service from consumers who still demand piped gas. While this may be economic for suppliers, withdrawing service may result in significant consumer costs to switch to alternative energy source. We will engage with policy agencies to highlight emerging issues from network rightsizing and consider whether appropriate protections are needed for consumers (eg, a withdrawal code).
Potential large-scale future network decommissioning costs **(Decision F2)**	We are not making a specific allowance for future decommissioning costs (or changing any existing regulatory setting) in DPP4. We do not have sufficient information about the basis for future decommissioning liabilities, or the likely type or scale of the costs. It is therefore not in consumers' interests to progress a specific solution for DPP4. We have referred issues raised by submitters in relation to network decommissioning to the Council of Energy Regulators at MBIE, the regulatory system's governance group, due to the likely wider policy implications affecting New Zealand's energy sector and security. We may consider the treatment as part of the next Part 4 IM review or as part of DPP5, when further information and greater clarity for the gas sector may have emerged.
Non-depreciable easements **(Decision F3)**	We are deferring consideration of this issue in the absence of information establishing that it is material for DPP4, or any other urgent or compelling reason to initiate an out-of-cycle review of the GDB and GTB IMs for the treatment of easements ahead of the DPP4 reset.

Issue	Our view
Cross-sector solution for addressing the impact of declining demand **(Decision F4)**	In submissions, Greymouth Gas proposed a conceptual solution for dealing with the impact of declining supply and demand for GPBs and gas consumers.[101] Broadly, it involves shifting the recovery of costs for a revalued portion of GPB RABs to consumers of electricity lines services. This proposal is out of scope of our regulatory regime (and therefore the DPP4 reset). It would be a significant policy decision to impose costs of one regulated service on consumers of another, and, as noted by Vector in cross-submissions, it is best considered as part of wider government policy processes.
Consumer disconnections	Some stakeholders identified disconnection policies and costs as an emerging issue, with suggestions that we introduce new standards for disconnections from gas networks. Submissions on our draft decision highlighted differences in current disconnection terminology, practices and costs. We consider that further information gathering and monitoring is an appropriate first step. We will consult on any information disclosure requirements in due course. This will increase transparency on how disconnections are carried out and help inform whether quality standards or other regulatory responses may be appropriate in the future. Disconnections are in scope of the GIC's Future of Gas Infrastructure workstream for 2027.[102] We will stay across this work and l take account of relevant sector and policy developments in considering any future regulatory response.

[101] Greymouth Gas "Gas DPP4 2026 – Views in response to issues paper" (27 July 2025); Greymouth Gas "Re: Gas DPP4 2026 – cross-submission" (13 August 2025).
[102] As set out for example in GIC "Briefing to Incoming Minister for Energy" (4 May 2026)