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Gas DPP4 reset 2026

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

Draft decision reasons paper - Attachments A - H

27 November 2025

Contents

Attachment A Regulating prices, revenue and quality

Purpose of this Attachment

A1 This attachment sets out details on the core components for how we have set price-paths for the Default price-quality path for the fourth regulatory period (**DPP4**). It covers:

A1.1 our approach to setting starting prices and the rate of change in subsequent years of the price path for the gas pipeline businesses (**GPBs**); and

A1.2 specific price path settings for the gas distribution businesses (**GDBs**) and the gas transmission business (**GTB**).

Structure of this Attachment

A2 In Table A1 below we describe the structure of this attachment.

Table A1 Structure of this attachment

Title	Description of content
Introduction	Sets out the purpose of this attachment, what it covers, and how it is structured.
Default price-quality regulation in DPP4	Describes the price paths which will apply to the GPBs in DPP4. Note that different forms of control will apply to the GDBs and the GTB.
Setting revenue for the GDBs	We describe the operation of the weighted average price cap (**WAPC**) and we note the decisions we made in the 2023 IM Review and other subsequent and potential IM amendments with respect to the IMs which will apply to the GDB price paths for DPP4.
Setting revenue for the GTB	We describe the operation of the revenue cap and we note the decisions we made in the 2023 IM Review and other subsequent and potential IM amendments with respect to the IMs which will apply to the GTB price path for DPP4. We describe the limitations that will apply to in-period revenue increases as a result of revenue wash-up accruals arising from short-term in-period revenue shocks and we then consider whether a price path reopener is necessary in addition to those capping mechanisms.

Default price-quality regulation in DPP4

Practical application of default price-quality regulation

Length of the regulatory period

A3 Our draft decision for GDB and GTB DPP4 is to set a five-year regulatory period commencing on 1 October 2026.[1] For our draft reasons, see our separate draft reasons paper which was published alongside our Issues paper in June 2025.[2]

How we set starting prices

A4 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:

A4.1 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.

A4.2 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.

A5 The two main components of the price or revenue limits which are specified in s 53O of the Act are:

A5.1 the 'starting price' allowed in the first year of the regulatory period; and

A5.2 the 'rate of change in price', or X-factor(s), relative to the consumer price index (**CPI**), that is allowed in later parts of the regulatory period.

We have set starting prices based on our assessment of current and projected profitability

Draft decision

A6 Our draft decision is to set starting prices for DPP4 based on current and projected profitability under the building blocks model (**BBM**).

Reasoning

A7 The Commerce Act allows us to set starting prices based on our assessment of current and projected profitability or by rolling over the prices which apply at the end of DPP3.[3]

[1] We have already published our draft decision on the length of the regulatory period and accompanying reasons. We will make our final decision on the length of the regulatory period in May of next year.
[2] Commerce Commission, "Gas DPP4 reset 2026: Five-year regulatory period - Draft decision reasons paper" (26 June 2025), which was published alongside our Issues paper.
[3] Commerce Act 1986, s 53P(3)(a).

A8 We sought feedback on this option in our Issues paper and stakeholders submitted against rolling over prices. In particular, Vector in its submission on our Issues paper submitted:[4]

> "154. We strongly recommend the Commission continue its approach setting starting prices based on its assessment of current and projected profitability under the building blocks model rather than the alternative approach of rolling over DPP3 prices.
>
> 155. In line with the Commission's reasoning in DPP3, using the building blocks model will better reflect the evolving circumstances of gas pipeline businesses and better create financial incentives to improve efficiency thereby aligning incentives between GPBs and consumers.

A9 We consider that using current and projected profitability better reflects the evolving operating environment of the gas sector than the alternative of rolling over prices. We are seeing declining gas production and lower volumes of gas being transported over the networks. In this context, it is appropriate to undertake an assessment of the GPBs' most up to date forecasts, asset management and operations plans and use these as the basis of calculating revenue forecasts to provide appropriate incentives to the GPBs to invest while limiting excessive profitability.

Setting starting prices based on an assessment of current and projected profitability (BBM)

A10 In line with our approach in DPP3,[5] we have set the revenue allowances and resulting starting prices using our 'building block' approach. The starting prices are an amount that does not include pass-through costs and recoverable costs. We have calculated the starting price amounts through two key processes:

A10.1 Process 1: Determining a building blocks allowable revenue (**BBAR**) for each year of the regulatory period. At the simplest level, the BBAR is calculated using separate cost building blocks as follows:

A10.1.1 Return on capital - Revaluations + Depreciation + Operating costs (**opex**) + Tax allowance. A high-level schematic is provided below in Figure A1; and

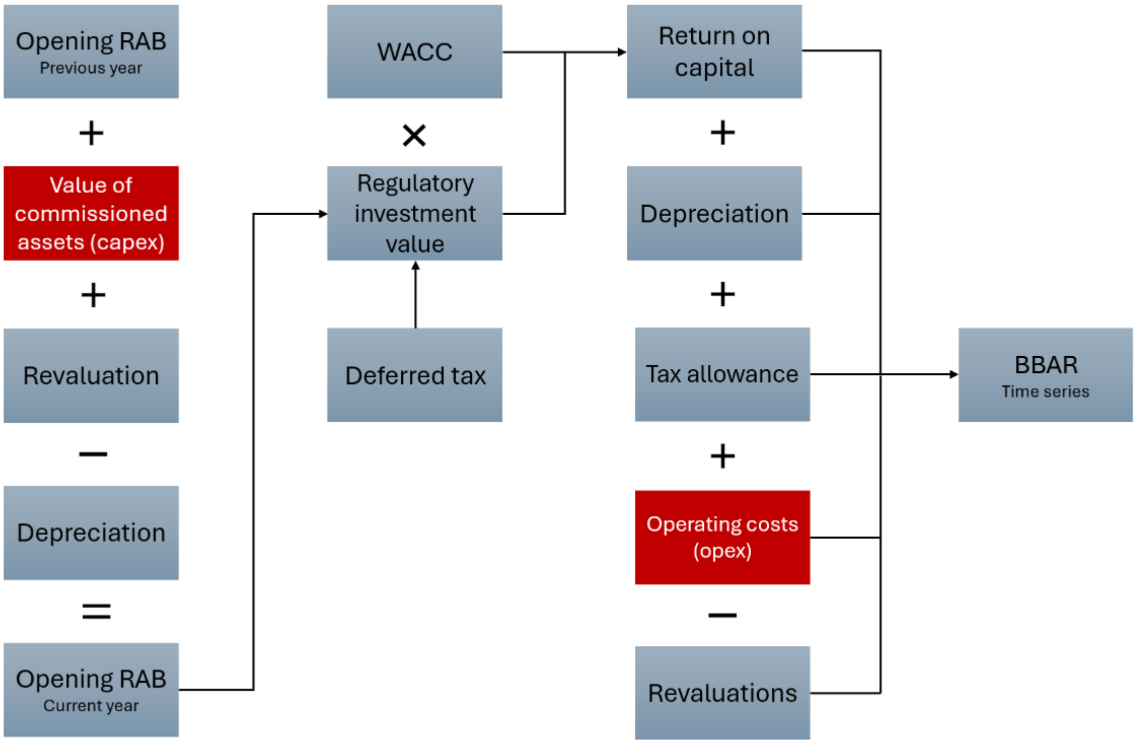
A10.2 Process 2: The annual BBAR amounts can vary markedly year by year. To avoid volatility in prices or revenues, we smooth the recovery of the BBAR amounts so that in present value terms, expected revenues earned over the regulatory period equate to the present value of the BBAR. We use CPI and the X-factor as well as the constant price revenue growth (**CPRG**) forecast for the GDB as the mechanism to smooth. A diagram of this step is provided below in Figure A2.

[4] Vector "Reset of the gas default price quality path 2026: Issues paper - Vector Submission" (24 July 2025), paras 154 to 157.

[5] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022) ,p.7.

A11 Using the fixed prices or revenue path (calculated using the BBM) creates financial incentives which align the GPBs' interests with those of consumers in reducing costs and becoming more efficient. This alignment of incentives is achieved over regulatory control periods, where the maximum revenue (or prices) for delivering the regulated services over the regulatory control period are specified up front.

Figure A1 Building blocks model used to calculate BBAR



A12 We highlight in red in the BBM description of Figure A1 two key inputs to the building blocks that are not determined by the input methodologies (**IMs**) and which we must forecast through the price-setting process. These two inputs are discussed in Attachments B and C:

A12.1 Capex, which represents the value of assets commissioned during the regulatory period); and

A12.2 Opex, or operating costs.

A13 Some inputs into the elements of the BBAR come from information disclosures. For example, we take the opening regulatory asset base (**RAB**) value as disclosed by the businesses as the starting point for calculating total regulatory investment value.

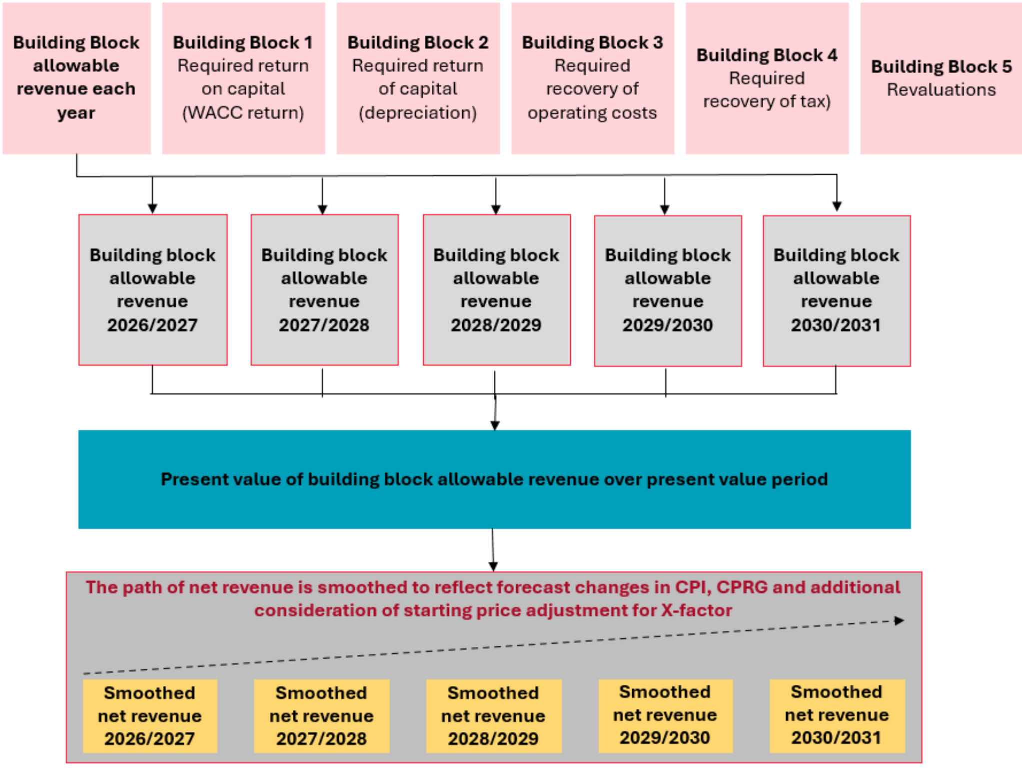
A14 Other inputs into the elements of the BBAR are wholly or largely set in the IMs. For example, the Cost of Capital IM sets out:[6]

[6] See for example *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, Part 4 Subpart 4.

A14.1 how we must estimate the weighted average cost of capital (**WACC**), including specifying values for most of the parameters eg; asset beta, leverage, tax-adjusted market risk premium (**TAMRP**); and

A14.2 the methodology for estimating the risk-free rate and the debt premium.

Figure A2 Setting forecast revenues equal to forecast costs



A15 Costs that are considered outside of the GPBs' control are recovered through separate allowances for 'pass-through costs'. Other costs that GPBs have little control over are recovered through allowances for 'recoverable costs'. The items that qualify under these categories, and the criteria for inclusion that must be satisfied, are set out in the respective GDB and GTB IMs.[7]

Setting revenue for the GDBs

Weighted average price cap to apply to the GDBs

A16 Under the GDB IMs, the GDBs are subject to a WAPC, which limits their maximum average prices during each year of the regulatory period.

[7] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, clauses 3.1.2 and 3.1.3, and *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clauses 3.1.2 and 3.1.3.

Constant price revenue growth forecasts

A17 For the GDBs we aim to set constant real prices over the regulatory period to deliver the present value of the BBAR. We determine starting prices that can be held constant over the regulatory period in real terms, taking into account forecasts of CPI and volumes (represented by our CPRG forecasts).

Draft decision

A18 Our draft decision is to use the latest GDB forecasts of demand and customer growth as the key input into our CPRG forecasts for DPP4. In order to obtain the most up-to-date demand and customer growth forecasts, we issued a request for information (**RFI**) to the GDBs to provide us with their most up to date demand forecasts. Where there was no response to the RFI, we used demand and growth forecasts contained in the disclosed asset management plans.[8]

A19 Our CPRG forecasts are as set out in Table A2.

Table A2 CPRG factors for DPP4 for each GDB

	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Firstgas Distribution	-0.91%	-2.15%	-2.27%	-2.51%	-2.70%	-3.15%
GasNet	-0.98%	-0.88%	-0.89%	-0.92%	-0.91%	-0.94%
Powerco	0.12%	-0.71%	-0.87%	-0.69%	-0.97%	-1.19%
Vector	-3.46%	-3.19%	-2.90%	-2.96%	-3.01%	-3.10%

A20 Declining CPRG factors means that revenue will be highest revenues at the start of the period before declining.

Reasoning

A21 The selection of volume forecasts informing our CPRG forecasts is a critical input in seeking to ensure that the resulting WAPC delivers an unbiased estimate of the prices required to deliver expected ex ante financial capital maintenance (**FCM**).

A22 For DPP3 we used the GDB's AMP forecasts of volumes to determine the CPRG forecast.[9] In our DPP3 Final Reasons Paper we said that the GDBs' AMP forecasts of gas demand were appropriate because we believed that those forecasts were credible and the best option available given the current gas demand uncertainty.[10]

A23 Our starting point for DPP4 was the to use the GDB's AMP forecasts to determine the CPRG forecast. We tested whether these were appropriate and credible similar to DPP3.

[8] We took this approach for GasNet who did not respond to our RFI.
[9] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), decision P6.
[10] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), para E63.

A24 There are incentives on the GDBs to adopt conservative forecasts of future volumes, as this may translate to higher prices, all else being equal. In coming to our decision to rely on GDB forecasts, we tested the GDB forecasts using independent forecasts to validate the reasonableness of the GDB forecasts.

A25 We engaged Concept Consulting to produce independent forecasts of demand and ICP growth. We used the Concept Consulting forecasts and compared these against the GDB forecasts.[11] We found that Concept Consulting's forecasts were consistent with the GDB forecasts and as such, we are satisfied that the GDB forecasts reasonably reflect anticipated demand.[12]

A26 We consider that using the GDB forecasts as the input into our CPRG to be appropriate for the following reasons:

A26.1 we consider GDBs have the best information on their existing consumers, enquiries from potential consumers, and their willingness to pay and trends in customer behaviour. They are forecasting their demand with the best possible information;

A26.2 the most recent forecasts reflect the most up-to-date expectations of demand; and

A26.3 independent testing of demand forecasts showed GDB forecasts are reasonable.

Incorporating Asset Management Plan forecasts in the forecast of gas demand

A27 In calculating the CPRG forecasts using the GDB's forecasts, there are calculation methodologies and assumptions which we must undertake.

A28 For the period of 2025 to 2031, we took the GDB's aggregate demand and installation control point (**ICP**) projections in their RFI responses and AMPs, and estimated the split between residential, commercial, and industrial consumer groups, followed by estimating the split between fixed price and variable price for each of the customer segments.

A29 Revenue by customer segments (residential, commercial, and industrial) from 2024 information disclosure (**ID**) was used to derive a notional proportion between these three consumer segments for each GDB.

A30 For each consumer segment for each GDB, we also calculated the weighting of fixed and variable charges based on its 2024 ID actual data related to GDBs fixed revenues.

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[11] Concept Consulting "Gas DPP4 draft demand forecasts report" (prepared for the Commerce Commission, 22 August 2025).

[12] For a comparison of difference between GDB forecasts and Concept forecasts, we have published Concept's report which demonstrates the difference between GDB forecasts and Concept forecasts of demand and ICP growth.

A31 We calculate the expected growth rate applicable to each consumer segment using the following methods:

A31.1 the growth for the fixed revenue component for each GDB is a linear growth rate based on the number for forecast ICPs for 2025-2032; and

A31.2 the growth rates for the variable revenue component for each GDB consumer segment are based on forecast gigajoule (**GJ**) growth relative to the previous year.

A32 We then apply the fixed and variable revenue weighting to the respective growth rates, for a total fixed component and annual variable components, for each GDB's consumer segments.

A33 Each GDB's consumer segments' CPRG is the total fixed component plus annual variable components. The total CPRG for each GDB is calculated as the weighted sum of the CPRG values across its three customer segments. We then make time adjustments for different year ends for the price path CPRG.

Under the WAPC the demand risk lies with the GDB

A34 Under the WAPC, the GDBs bear the in-period demand risk. Demand risk falls on GDBs as, when volumes vary, the weighted average prices GDBs can charge remain the same. If quantities delivered fall below forecast quantities, GDBs earn less revenue until prices are reset at the next regulatory period. They also receive the upside of this risk. If they outperform the forecast of quantities delivered, they retain the additional revenue during the DPP.

A35 While there is a capacity event reopener to meet any need for additional capacity, there is no demand event reopener to enable a GDB to apply for the reconsideration of the price-quality path part way through the regulatory period if there is a material change in demand relative to the demand forecasts on which the DPP is based.

Consideration of mechanisms to deal with short term in-period demand risk

A36 In submitting on our open letter, GDBs noted that short term demand risk (ie, in-period demand variation) is a key challenge for them, and they proposed we look at potential hybrid price path adjustment mechanisms which could involve the sharing of this risk between GPBs and consumers.[13] [14] [15]

A37 The GPBs also noted that IM amendments could be required, to the extent that the matter of in-period demand variation could not be resolved through the DPP4 reset.[16]

[13] Firstgas "Submission on the Gas DPP4 Open Letter" (13 March 2025), pp.5 and 6.
[14] Powerco "Submission on Gas DPP4 Open Letter" (13 March 2025), p.1, 2 and 5.
[15] Vector "Submission on Gas DPP4 Open Letter" (13 March 2025), pp.1 and 2.
[16] Firstgas, Powerco & Vector "Joint submission on Gas DPP4 Open Letter" (13 March 2025), p.2.

A38 In its submission, the Major Gas User's Group (**MGUG**) provided context on the reasons for gas scarcity, and it submitted against further shifting demand risk burden to consumers.[17]

A39 We set out our views on tools to address demand variation below.

Stakeholder submission on mechanisms to address large in-period demand variations and our view on submissions

A40 In response to our issues paper, we heard from submitters on the demand variation risks and what they consider should be done to address the risk.

A41 The GDBs jointly submitted:[18]

> The question then is whether and how the uncertainty around the demand forecasts adopted for the DPP4 reset should be dealt with. If the uncertainty is material – which we consider it is – then the case for doing something is relatively straightforward. Higher uncertainty leads to more scope under a WAPC for GDBs to outperform or underperform against allowed revenue, with potential adverse consequences for gas consumers.

A42 Vector submitted:[19]

> If the Commission retains a weighted average price cap, we consider it critical another mechanism to address forecast risk is implemented to preserve incentives to invest.
>
> We support the Commission further investigating implementing a hybrid approach between the weighted average price cap and revenue cap, such as that proposed by Jemena in NSW (and accepted by the AER) through its 'hybrid tariff variation' mechanism. This would have the benefit of sharing risk more equally between consumers and GPBs…

A43 Powerco submitted on our Issues paper:[20]

> Leading up to DPP4, circumstances have changed such that a revenue cap would now be a more suitable form of control. However, we accept that the Commission is unwilling to reconsider this off the back of the 2023 IM review. In the absence of a re-thinking of the form of control, we generally support the retention of existing arrangements, if these are supplemented with adjustments to recognise the particular forecasting risks in this DPP4 period and mechanisms to respond should these risks have material impact. We are particularly mindful that if shocks happen early in the period, waiting 3-4 years to be corrected could be detrimental to consumers and to GDBs incentives to invest…
>
> While we agree with the Commission's assessment of demand risk sharing, the significant risk that requires a mitigation mechanism is forecasting risk – it is inherently harder to forecast in an uncertain environment…

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[17] MGUG "Submission on Gas DPP4 Open Letter" (13 March 2025), p.10.
[18] Firstgas, Powerco, Vector "Letter to the Commission" (24 July 2025), p.7&8
[19] Vector "Reset of the gas default price-quality path 2026: Issues paper – Vector submission" (24 July 2025), para 53 to 58
[20] Powerco "Submission on Gas DPP4 issues paper" (24 July 2025), p.4 & 5

A44 Entrust, Vector's major shareholder, submitted:[21]

> Demand for gas is expected to continue to decline but the gas sector faces uncertainty about the rate at which it will decline. GPBs face risk that the actual volume of demand declines at a faster rate than the Commission forecasts for its DPP reset, and connections/disconnections differ from forecast. This is what happened to Vector over DPP3 with the real revenue growth rate lower than the Commission's assumptions used in the price-path. The Commission acknowledged "the pace of decline was quicker than anticipated.

A45 MGUG does not support any sharing of risk on short term demand risk variations:[22]

> We do not support a GDB proposal that risk of short-term demand risk variations requires more "risk sharing" and demand event openers. Risk sharing seeks simply to transfer more demand risk on consumers when in fact the point of a WAPC is that GDBs can influence demand and are the best party to manage that risk. We agree with the Commission's position on this, particularly because GDBs continue to act to disincentivise consumer connections within their own policies.

A46 While we have heard from stakeholders about what they perceive to be the issue that should be addressed, we have not been presented with submissions setting out the quantum of risk to the long-term benefit of consumers resulting from the demand risk.

We considered a new WAPC variation mechanism like one used in Australia and a reopener

A47 Our draft decision is to not implement a demand variation mechanism to allocate some of this risk to consumers.

A48 While we understand suppliers' submissions on the option to implement hybrid price-path mechanism similar to what the Australian Energy Regulator (**AER**) approved for Jemena Gas Networks' 2025-30 price path reset, we did not receive any submissions quantifying the potential risk for consumers resulting from a large demand shock. Given the lack of evidence of potential harm to consumers resulting from demand shocks we are not satisfied that a hybrid price-path mechanism would best promote the long-term benefit of consumers under s 52A of the Act. In particular, we have accepted the businesses' demand forecasts. We expect that these would be a central estimate of forecast demand and include prospects of both potential for upside improvement as well as downside risk.

A49 The GDBs demand forecasts are likely to factor in any demand uncertainty. We have set our demand forecasts based on the GDB's forecasts of demand as we consider them to be a reasonable forecast reflecting consumer demands.

A50 In addition, under our existing WAPC as specified in the IMs and DPP, the GDBs are able to manage their businesses to take account of variations in demand through:

A50.1 management of expenditure;

[21] Entrust "Submission on Gas DPP4 Issues paper" (24 July 2025), p.5
[22] MGUG "Submission on Gas DPP4 Issues Paper" (28 July 2025), para 18

A50.2 restructuring pricing;

A50.3 application for a customised price-quality path (**CPP**); and

A50.4 application for a capacity event reopener.

A51 We also considered the reopener to address significant demand variations, but note that we have not satisfied ourselves that there is new evidence to the quantum of risk to consumers which justifies a shift from our position to not introduce a demand reopener in the IM Review 2023.[23] However, we do consider the ability CPP applications would be a better mechanism to undertake a bottom-up forecast and assessment of what is necessary to continue to efficiently provide services at level demanded by consumers.

A52 In submissions on the suite of draft decisions, we encourage submitters to present further evidence and analysis on the need for a demand variation mechanism. This could include demonstrating credible evidence showing asymmetric outturn demand distributions to show quantum of variation (particularly demonstrating the risk is asymmetric).

Setting revenue for the GTB

Revenue cap with wash-up will apply to the GTB

A53 Under the GTB IMs, the GTB specification of 'price' is set out as an ex-ante revenue cap, where:[24]

A53.1 the forecast revenue from prices in each pricing year must not exceed the forecast allowable revenue for that pricing year; and

A53.2 the forecast revenue from prices less forecast pass-through costs must not exceed the revenue smoothing limit specified in the GTB DPP determination for each pricing year other than the first pricing year in the regulatory period.

A54 The revenue cap will be subject to an ex-post wash-up mechanism, where:[25]

A54.1 a 'wash-up accrual amount' will be calculated for each pricing year, being actual allowable revenue less actual revenue for the pricing year;

A54.2 the wash-up accrual amounts will be accumulated in the 'wash-up account balance' with a time value of money adjustment at the mid-point estimate of WACC as the balance is rolled forward from year to year, with a slight variation in methodology for the balance rolled forward from DPP3 to DPP4; and

A54.3 a 'wash-up drawdown amount' will be calculated for each pricing year and specified in the GTB DPP determination to allow the wash-up account

[23] Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), paras 3.499-3.508.
[24] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, cl.3.1.1(1).
[25] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, cl.3.1.4.

balance to be recovered as a recoverable cost, with the objective of ultimately drawing down the balance to zero over time.

A55 Under the revenue cap, consumers bear the in-period demand risk. The purpose of the annual wash-up mechanism is to ensure that revenue is not over- or under-recovered during the regulatory period, given the forecast revenue for each year is based on prices multiplied by forecast quantities.

A56 The GTB can set prices in a manner consistent with the relevant transmission and operating codes, but it cannot exceed the revenue cap.

How changes to the IMs since DPP3 be applied to the GTB revenue cap

A57 The GTB revenue cap is being carried forward from DPP3 with price path wash-up amendments from the 2023 IM review.[26]

A58 The GTB IM changes to the specification of price provisions made as part of the 2023 IM review and those we are proposing for this reset largely replicate the changes which were made to the Electricity Distribution Businesses (**EDB**) IMs with respect to the specification of price that applies to EDBs in EDB DPP4 and for this reason, subject to any specific context applying to the GTB, we are adopting many of the price path implementation details from the EDB DPP4 determination.[27]

A59 In the IM Review 2023, we made a suite of changes to the revenue wash-up provisions in the GTB IMs including a shift from individual building block wash-ups to a 'one big bucket' approach to wash-ups to aggregate the wash-up calculation and changes to reduce volatility in pricing.[28] For the purposes of the DPP4 reset, the following IM changes are particularly relevant:

A59.1 replace the "annual maximum percentage increase in forecast allowable revenue as a function of demand" with a "revenue smoothing limit";

A59.2 include the voluntary "undercharging limit" on the revenue path for GTBs; and

A59.3 the ability for the Commission to specify the pace of drawdown over subsequent regulatory periods, for the purpose of returning the wash-up account balance towards zero over time.

A60 These IM changes require us to specify the method and amounts for these limits and drawdown pace in the DPP and as such, will require a decision as part of this DPP reset.

[26] Commerce Commission "Report on the IM Review 2023 - Part 4 Input Methodologies Review 2023 - Final decision" (13 December 2023), *Current specification of price IM decision SP02*, p.81, para 7.12
[27] *Electricity Distribution Services Default Price-Quality Path Determination 2025* [2024] NZCC 28
[28] Commerce Commission "Report on the IM Review 2023 - Part 4 Input Methodologies Review 2023 - Final decision" (13 December 2023), *Current specification of price IM decision SP01*, pp. 78 – 81.

Limiting inter-period revenue increases under the GTB revenue cap

A61 The GTB IMs now include a high-level description of the revenue smoothing limit and the undercharging limit, implemented as part of the suite of changes in the IM Review 2023 to better manage inter-period volatility.

A62 As far as the carry-forward of any large wash-up accrual amount in the GTB wash-up account balance goes, there is an effective cap on the amount that can be recovered in prices (ie, revenues) in under the GTB IM determination in the 'revenue smoothing limit'.[29] The rate of that limit is set in the DPP determination.

A63 This is a new feature that we are porting across from the EDB IMs as a result of the 2023 IM Review and we now need to copy the relevant implementation details into the DPP determination from the EDB DPP determination.

A64 The revenue smoothing limit works to limit the maximum amount a supplier can charge in any given year with the result that it limits volatility and price shocks by creating an effective 'cap' on the price increases passed to consumers in each year. In setting a DPP, we have the ability to set the details (including the amount and form of increases) of the revenue smoothing limit. This means that we may set an amount such that price increases in each year that would not result in a 'price shock'.

A65 The cap limits the amount of the 'forecast revenue from prices' at the sum of the forecast net allowable revenue plus the forecast recoverable costs for the prior pricing year, multiplied by the 'revenue smoothing limit'. In the case of the EDBs we set the formula as the forecast CPI for revenue smoothing plus 10% (ie, effectively a real 10% increase in the recoverable costs each pricing year compared to the prior pricing year).

Draft decision and reasons

A66 Our draft decision is to implement the revenue smoothing limit and undercharging limit as required by the wash-up provisions in the GTB IMs (similar to EDB DPP4) into the GTB DPP4 determination, including a 10% revenue smoothing limit,[30] but not specify a threshold factor in the undercharging limit.[31]

A67 We have set a 10% cap as we currently consider a 10% cap reflects a balance between ensuring prices reflect the costs of providing the service and minimising price shocks to consumers, therefore promoting the s 52A purpose.

[29] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 3.1.1(1)(b).
[30] *Electricity Distribution Services Default Price-Quality Path Determination 2024* [2024] NZCC 28, Schedule 1.5.
[31] *Electricity Distribution Services Default Price-Quality Path Determination 2024* [2024] NZCC 28, Schedule 1.7.

A68 Our reason for including the forecast recoverable costs in this calculation is primarily because the wash-up drawdown amount for a pricing year is a recoverable cost under the GTB IM determination,[32] and this has the effect of limiting the level of the drawdown amount that the GTB can recover in a year.

A69 If this 10% limitation cuts in for a pricing year, the GTB must recover a wash-up drawdown amount that is lower than the wash-up account balance. Under the GTB IM determination the GTB is allowed to set a drawdown amount of between zero and the wash-up account balance two years prior.[33] The GTB would therefore need to set a value that sits somewhere in that range that meets the revenue cap requirement in order to meet the revenue smoothing limit.[34]

A70 Because the wash-up account balance set out in the GTB IM determination only reduces the account balance in a pricing year by the actual amount drawn down, the rest of the wash-up account balance after application of the revenue smoothing limit will roll forward until the GTB elects in a future pricing year to recover the remaining balance. The amount is not revenue foregone in that instance.[35]

How this can limit in-period demand shocks for GTBs

A71 Under the GTB revenue wash-up any sudden large decline in revenue could result in a large ‘wash-up accrual amount’ which would enter the wash-up account balance and be able to be recovered by the GTB in future pricing years.

A72 In its submission on our open letter, MGUG comments on large in-period increases in transmission prices in DPP3.[36] Based on our initial review of Firstgas' DPP3 disclosures,[37] [38] a significant part of the changes each year in Firstgas' DPP3 transmission revenue appears to be attributable to larger than expected revenue wash-ups caused by large one-off in-period reductions in demand.

A73 We consider the revenue smoothing limit and the effective cap it creates will address some of the concerns about large in-period increases raised by MGUG.

[32] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 3.1.3(1)(k).
[33] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 3.1.4(5)(a).
[34] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 3.1.1(1)(b).
[35] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 3.1.4(1)(d).
[36] MGUG “Submission on Gas DPP4 Open Letter” (13 March 2025), para 24.
[37] Firstgas Transmission "Gas transmission services: Compliance with the wash-up amount calculation and quality standards" (February 2024), Assessment Period 1 October 1 October 2022 – 30 September 2023.
[38] Firstgas Transmission "Gas transmission services: Compliance with the wash-up amount calculation and quality standards" (February 2024), Assessment Period 1 October 2023 - 30 September 2024.

DPPs are not used to regulate GPB pricing methodologies

A74 DPPs set the maximum forecast revenue GPBs can recover and for the GDBs, the resulting maximum aggregate prices it may charge over the regulatory period. We do not set individual prices/tariffs for services provided by the GPBs and we do not regulate the pricing methodology of GPBs through the GDB DPP or GTB DPP. However, the GDB and GTB IMs require GPBs to publicly disclose their pricing methodologies and how they calculate their prices and, for the GDBs, how this complies with the WAPC.[39]

A75 The purpose of ID is to ensure that sufficient information is readily available to interested persons to assess whether the purpose of Part 4 in section 52A of the Commerce Act is being met.[40]

A76 Under the GPB ID determinations, the GTB and GDBs are required to make annual disclosures about their pricing methodologies.[41,42] These include demonstrating the extent to which their pricing methodology is consistent with the pricing principles set out in the GTB and GDB IMs.[43] [44] They are required to explain any inconsistencies between their pricing methodology and those pricing principles.

A77 The most recent published GPB pricing methodologies for the 2025 pricing year from 1 October 2024 to 30 September 2025 are published on the GPB websites. [45,46,47,48,49]

A78 Some submitters on our open letter highlighted that some GDBs were charging a greater proportion of their revenue through fixed charges each year.[50] [51] MGUG suggested that we look at whether GDBs are shifting their demand risk onto consumers by proportionally increasing their fixed revenue recovery from consumers by transferring more revenue to fixed connection charges.[52]

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[39] Commerce Act 1986, s 53A.
[40] Commerce Act 1986, s 53A.
[41] *Gas Transmission Information Disclosure Determination* [2012] NZCC 24, clause 2.4
[42] *Gas Distribution Information Disclosure Determination* [2012] NZCC 23, clause 2.4.
[43] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clauses 2.5.1 and 2.5.2.
[44] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, clauses 2.5.1 and 2.5.2.
[45] First Gas "Pricing Methodology for Gas Distribution Services - From 1 October 2024 (Pricing Year 2025)" (30 September 2024).
[46] GasNet "2024/25 Pricing Methodology - Gas Distribution Network Services - Valid from 1 October 2024 to 30 September 2025" (30 August 2024).
[47] Powerco "Gas Distribution Pricing Methodology - October 2024 - September 2025" (September 2024).
[48] Vector "Vector Gas Distribution Services 2025 Pricing Methodology - From 1 October 2024".
[49] Firstgas "Pricing Methodology for Gas Transmission Services - From 1 October 2024" (1 September 2024).
[50] Aluminium Extruders Association of New Zealand (ALENZ) "Submission on Gas DPP4 Open Letter" (12 March 2025), p.1.
[51] MGUG "Submission on Gas DPP4 Open Letter" (13 March 2025), para 15.
[52] MGUG "Submission on Gas DPP4 Open Letter" (13 March 2025), para 21.

A79 While we have general pricing principles specified in our IMs, our suite of regulation does not prescribe specific limits on how GDBs must set individual tariff levels and we do not assess the balance of pricing.

A80 Under a weighted-average price cap form of regulation, the businesses are incentivised to determine a reasonable balance between fixed and variable charges. Excessive fixed charges that cause consumers to disconnect from the network would result in lower revenues to the GDBs that cannot be recouped, whereas under revenue cap regulation, that risk would be removed from the GDB.

A81 The management response to changes in demand includes changes in pricing which we consider is consistent with the allocation of demand risk under the WAPC (ie, not shifting more risk onto consumer). It places intra-period demand risk on GDBs and gives the GDBs an incentive to manage demand risk and respond to changes in demand. While it may be able to shift some of the demand risk associated with demand for throughput of gas, there would be a proportionate increase in connections demand risk (e.g. low volume consumers may exit) so the GDB must still manage that aspect of demand risk.

A82 Based on the evidence presently available to us, it is not evident that tariff restructuring is inconsistent with s 52A of the Act and we consider they are permitted to do so under the current WAPC.

Attachment B Forecasting capital expenditure

Purpose of this attachment

B1 The purpose of this attachment is to explain how we have set capex allowances for Gas DPP4.

B1 This attachment sets out:

B1.1 a summary of our draft decisions capex allowance settings and modelling approach for each year of DPP4 (see Table B1);

B1.2 a description of our approach to setting DPP4 capex allowances;

B1.3 how we set capex allowances for GDBs related to asset replacement and renewals, consumer connections, system growth, non-network and reliability, safety and environment;

B1.4 how we set capex allowances for Firstgas Transmission;

B1.5 how we set capex allowances for asset relocations for all GPBs;

B1.6 how we set a revised cost of finance value; and

B1.7 how we convert constant $ 2025 capex to nominal values.

B2 We have performed all capex analysis using historical and forecast expenditure in constant $ 2025 prices (**$ 2025**). All expenditure in this attachment is expressed in constant $ 2025 prices and assessed net of capital contributions unless stated otherwise.

Summary of our draft decision

B3 Table B1 sets out our capex allowance draft decisions for the GDBs and GTB over DPP4.

Table B1 Our capital expenditure allowance draft decisions ($000s 2025)

GPB	GPB forecast	GPB Draft allowance	Allowance to forecast (%)
Firstgas Transmission	163,925	157,908	96%
Firstgas Distribution	24,274	21,410	88%
GasNet	4,905	2,483	51%
Powerco	72,032	47,207	66%
Vector	19,815	18,743	95%
Total	**284,951**	**247,750**	**87%**

Setting capex allowances

B4 For this draft decision, our approach to setting capex allowances for the DPP4 period draws on the approaches we have used in the past, with adjustments to reflect updated GPB forecasts of declining gas production and new gas connections.

What we said in our Issues Paper

B5 In our June 2025 DPP4 Issues Paper, we proposed to focus on how GPBs were revising their asset management strategies in response to current market conditions and emerging risks.[53]

B6 To inform our setting of capex allowances for DPP4, we set out our early views on a likely approach:

B6.1 use the GPBs 2025 Asset Management Plan (**AMP**) forecasts and cross-check these against the most recent historical disclosures to ensure that the most recent trend in growth (or decline) was reflected in forecast amounts;

B6.2 review GPB capital contribution policies and consumer connection forecasts to assess the reasonableness of proposed expenditure;

B6.3 apply targeted scrutiny to any growth capex (consumer connection and system growth) to assess whether forecasts are supported by strong evidence which includes:

B6.3.1 consistency between proposed expenditure and GPB forecasts of conveyed gas volumes and new connections; and

B6.3.2 explanation of how asset stranding risk had been considered in the forecasting process, aligning with our DPP3 asset life decision;

B6.4 apply scrutiny to uplifts in forecast expenditure – particularly noting the increase in asset replacement and renewal (**ARR**) proposed by Powerco and GasNet.

B7 We also signalled we planned to look at changes in ARR capex and network opex to identify any capex/opex trade-offs that may be occurring to ensure these are to the long-term benefit of consumers.

Issues Paper submissions

B8 We received a number of submissions and cross submissions to our Issues paper commenting on aspects of the proposed capex allowance setting approach.

[53] Gas DPP4 reset 2026 Issues paper – Attachment B, pp.28-30.

B9 There was general agreement that historical expenditure is no longer a good predictor of future expenditure (GPBs, Fonterra, Entrust):[54]

> While historical capex levels have provided a useful baseline in the past, they are no longer an appropriate predictor of future needs in the context of New Zealand's evolving energy landscape and declining connection trends.[55]

B10 Powerco supported an AMP-based expenditure setting approach with scrutiny:

> Additional scrutiny of AMPs is an appropriate approach and our AMP25 will address many of the matters covered in the Issues paper.[56]

B11 Similarly, an AMP based approach with scrutiny was supported by MGUG:

> We support the Commission reviewing GPBs AMPs to understand how their investment strategies are being adapted to optimise expenditure on their networks, and therefore how the AMPs can inform Commission setting of the expenditure allowances. We would expect the Commission to use independent advice from suitably qualified providers to assist in this assessment.[57]

B12 Vector highlighted the need for expenditure allowances to accommodate evolving asset management strategies, recognising the substitution of capex for opex:

> Vector's forecast capex in the 2025 AMP is substantially lower than the 2024 AMP, while forecast opex has increased. This reflects that, as part of a prudent, risk-based approach to asset management, Vector is reducing capex on asset replacement and replacing it with increased annual opex on maintenance.[58]

B13 Fonterra supported an AMP-based approach that allows capex/opex substitution:

> By relying on up-to-date AMP forecasts (Rather than an automatic historic average) and allowing capex-to-opex substitution, the Commission's draft approach should ensure renewals projects that are only justified by keeping the RAB high are avoided.[59]

B14 Vector supported targeted scrutiny of any uplift or growth categories.[60]

B15 There were a range of views on consumer connection capex from those who argued that new customers should pay the full upfront cost of connection and future disconnection (Fonterra), to those who emphasised the importance of maintaining cost-sharing across a broad customer base and cautioned against rigid capital contribution rules that could discourage connections and destabilise the network (Nova and Powerco).

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[54] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p.10, Entrust "Submission on Gas DPP4 Issues paper, draft decision regulatory period paper; Fibre IM Review Issues paper" (24 July 2025), p.8, Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), p.2, Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p.8, Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.10.
[55] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.10.
[56] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p.1.
[57] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 3
[58] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p.9.
[59] Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), p.2.
[60] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p.32.

> We support the new-connection solution outlined in section 3.22. All new customer connections should be priced to recover the full capital and future disconnection cost up-front, so that existing are not required to underwrite either today's or tomorrow's costs of connecting customers.[61]
>
> New customers should be charged upfront for the full cost of their connection. Connecting to a network which is beginning planning for decommissioning over the coming decades is a sunk and stranded cost.[62]
>
> Nova is concerned that Vector, at least, appears to be limiting or discouraging new consumer connections. While this may be rational from a GDB perspective, it undermines the cost-sharing benefits of a broad customer base and risks driving up prices for remaining users. As the Commission notes in this Issues paper, fewer users over time can lead to higher costs for those who remain connected. The Commission should consider mechanisms that ensure connection policies remain supportive of long-term cost-sharing. That may mean using different depreciation allowances for sunk and new investments.[63]
>
> We are concerned regulatory intervention which disallows connection capex and requires 100% capital contributions, may force a market outcome e.g. trigger a death spiral for gas pipelines, as it's likely customers will be less willing to connect, at a time when there is still benefit in having new customers connect. A customer contribution level shouldn't be 0% or 100% but something in between that balances risk and response. We strongly encourage the Commission to not make drastic changes in DPP4, given there is still so much uncertainty across all elements of the market (policy, demand, supply).[64]

B16 We have considered the points raised in response to our Issues Paper within our proposed approach to setting capex allowances within this paper.

How we have set capex allowances

Using the GPB AMPs as the source for GPB forecast expenditure information

B17 Stakeholders generally agreed that using AMP disclosures was the most appropriate source for GPB forecast information and was appropriate and consistent with a relatively low-cost regime.

B18 Our view is that the AMP forecasts are the most complete information available and are a suitable source for GPB forecast expenditure information. However, we did not consider it appropriate to fully adopt all GPBs' AMP forecasts as capex allowances for DPP4.

B19 We have assessed GPBs' 2025 AMP forecasts compared to their historical expenditure.

B20 We have reviewed supporting information contained within AMPs. Given the late finalisation of 2025 AMPs for Powerco and Firstgas relative to timing of our expenditure assessment process this included assessment of their previous AMPs.

[61] Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), p.2.
[62] Rewiring Aotearoa "Submission on Gas DPP4 Issues paper" (24 July 2025), p.6.
[63] Nova Energy "Submission on Gas DPP4 Issues paper" (23 July 2025), p.1.
[64] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), pp.12-13.

B21 Where further supporting information was required to understand investment drivers we have issued targeted Requests for Information (**RFIs**).

Establishment of the reference period for comparison

B22 Where we used historic average, we used a five-year reference period. Using past expenditure for comparison against future expenditure requirements provides an understanding of relative scale of change and accounts for network characteristics in a relatively low-cost way.

B23 We consider a five-year period reflects the changing nature of expenditure within the sector and provides a large enough sample to average out investment timing differences. Where current investment conditions are more likely to vary from historic, in particular for consumer connection and system growth, there is less reliance in our approach on the historic average.

In the DPP4 period, we are taking a category level approach to assess the GPBs' capex.

B24 In our analysis, rather than take a total capex approach, we investigated each of the capex categories individually to gain insight into what was driving expenditure forecasts. Given the context for gas the expenditure categories are likely to reflect distinct underlying drivers of cost and accordingly are appropriate to assess individually.

B25 The capex categories are:

B25.1 asset replacement and renewals (**ARR**);

B25.2 consumer connection (**CC**);

B25.3 system growth (**SG**);

B25.4 non-network (**NN**); and

B25.5 reliability, safety and environment (**RSE**).

B26 Our analysis has primarily focussed on:

B26.1 material capex categories (**ARR** and **NN**); and

B26.2 categories that warranted closer scrutiny and where alternative allowance setting approaches to accepting the GPB 2025 AMP forecasts may be appropriate (CC and SG).

Breakdown of capex forecasts by category

B27 For each GPB we provide a breakdown of capex forecasts by category based on the 2025 AMPs. Figure B1represents the percentage for each category and Figure B2 the amounts ($ 2025).[65]

[65] Note that the expenditure data we present throughout this attachment is net of capital contributions.

Figure B1 Percentage breakdown of capex by category for all GPBs

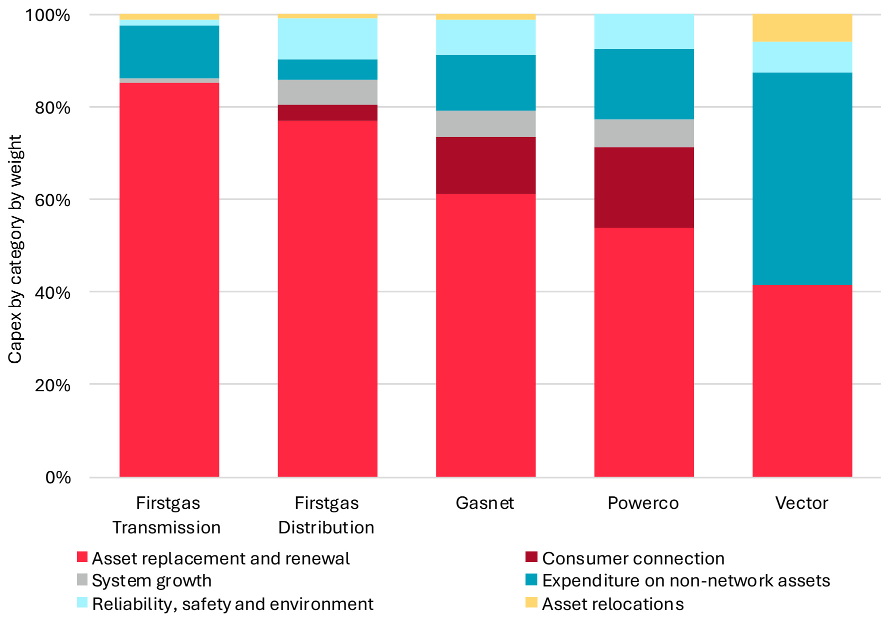
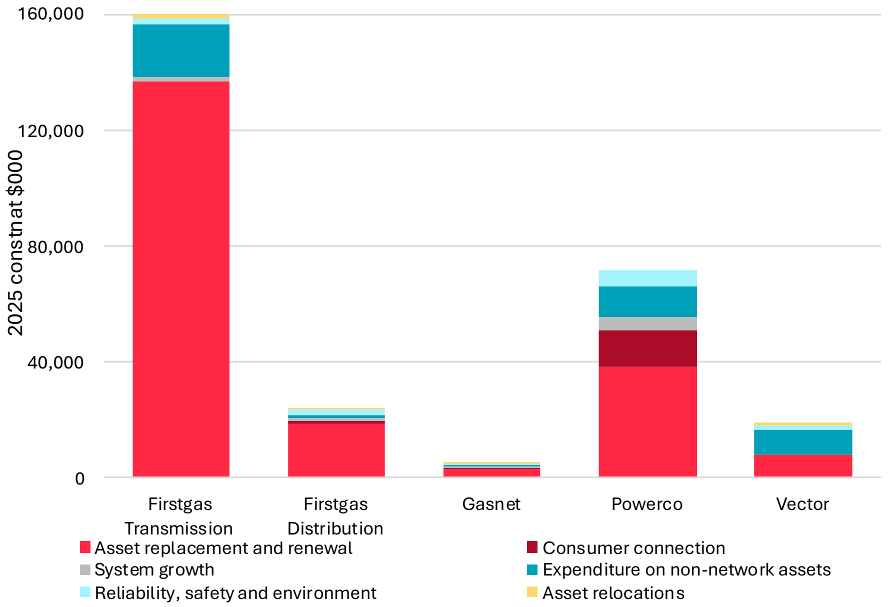


Figure B2 Capex by category for all GPBs



B28 In the following sections we explain our analysis. We have split the analysis between the GDBs and the GTB for most expenditure categories, given the driver for asset relocations is consistent across networks this has been assessed on a combined basis.

Setting GDB asset replacement and renewals capex allowances

Summary of our draft decision

B29 Our draft decision for the ARR capex category is to take the same approach we took in DPP3, allowing each GDB's forecast capex unless it exceeds historical average real capex. Table B2 sets our expenditure analysis conclusions in this capex category.

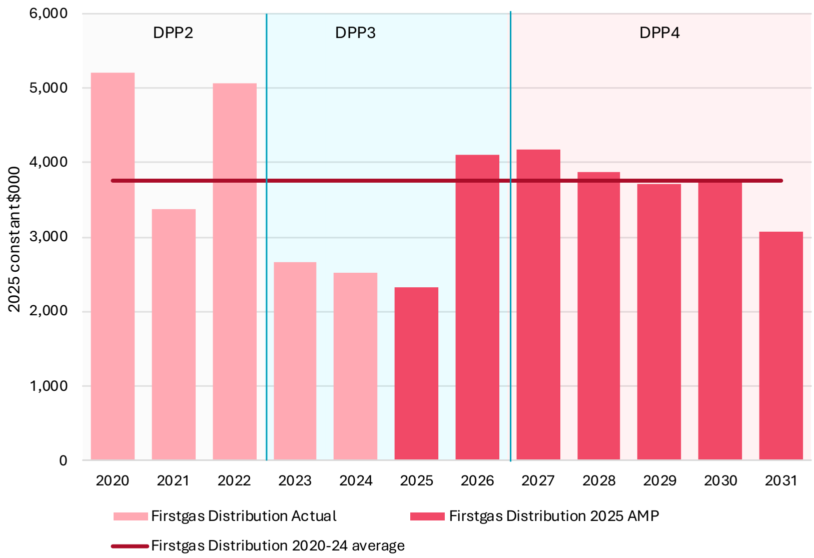
Table B2 Asset replacement and renewals forecast and draft decision allowances ($000's 2025)

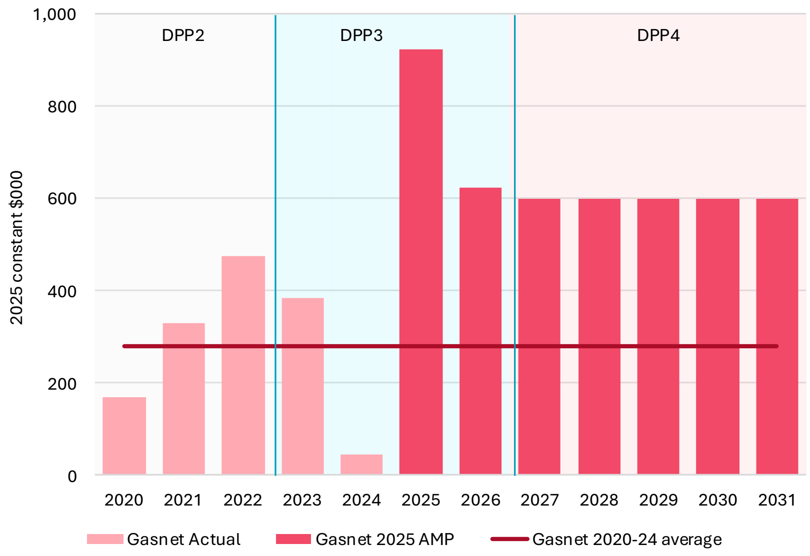
GDB	GDB forecast	GDB Draft allowance	Reduction
Firstgas Distribution	18,605	18,091	514 (3%)
GasNet	3,000	1,406	1,594 (53%)
Powerco	38,622	28,249	10,373 (27%)
Vector	8,064	8,064	0 (0%)

Background and analysis

B30 Forecasts for ARR vary across GDBs, with Firstgas Distribution forecasting ARR expenditure that is relatively consistent with the historical 5-year average, both GasNet and Powerco forecasting an increase, and Vector forecasting a significant reduction (see Figure B3).

Figure B3 GDB asset replacement and renewals capex forecasts and actuals ($000's 2025)




1,000
800
600
400
200
0
2025 constant $000
DPP2
DPP3
DPP4
2020
2021
2022
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2028
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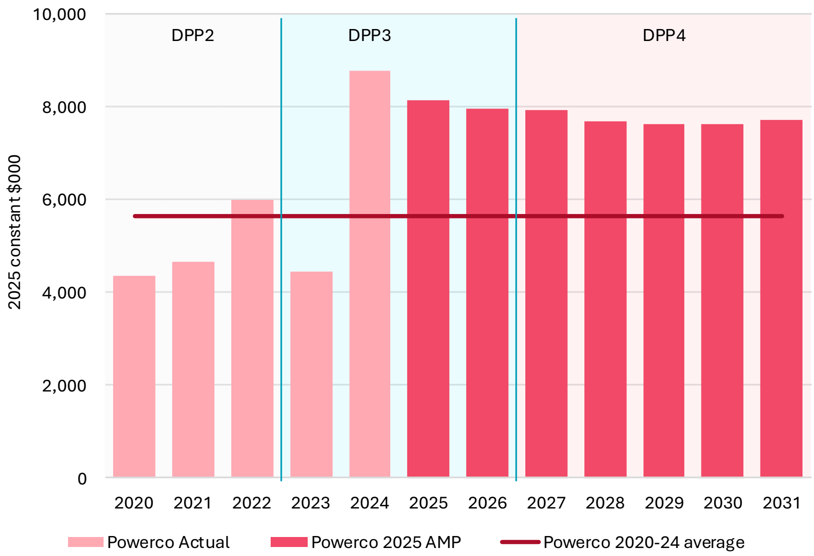
2030
2031
Gasnet Actual
Gasnet 2025 AMP
Gasnet 2020-24 average


10,000
8,000
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4,000
2,000
0
2025 constant $000
DPP2
DPP3
DPP4
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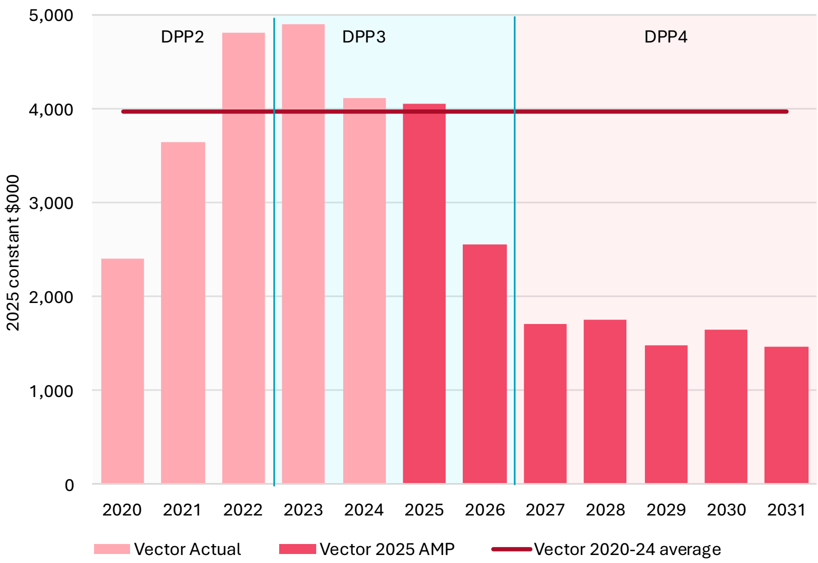
2029
2030
2031
Powerco Actual
Powerco 2025 AMP
Powerco 2020-24 average


5,000
4,000
3,000
2,000
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0
2025 constant $000
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Vector Actual
Vector 2025 AMP
Vector 2020-24 average

Approach to setting ARR capex allowances

B31 For this draft decision we have taken the same approach that we took in DPP3, allowing each GDB's forecast capex unless it exceeds a projection of historical average real capex, assessed individually for each year of the regulatory period. Where the forecast amount is less than the historical average capex, we have set the allowance at the 2025 AMP forecast amount.

B32 This approach may reward GDBs that are forecasting more sustained levels of ARR as gas volumes decline. We recognise that replacement and renewals work (whether this is capex or opex) will still be necessary to maintain a safe and reliable supply.

B33 We consider that in the current context historical ARR capex may not be as strong a predictor of future need as it has in previous periods and expect GPBs to be undertaking more detailed assessment on asset age and cost information to determine replacement strategies. We have concerns that despite identified capex-opex trade-offs, some GPBs are forecasting consistent levels of ARR capex and opex step change increases related to trade-offs. Our assessment of the appropriateness of the opex step changes is contained in Attachment C.

B34 To mitigate the risk that the capped DPP expenditure allowances will be insufficient to address network risk issues, GDBs have access to the 'resilience or asset relocation event' and 'risk event' reopener mechanisms introduced in DPP3. These reopeners apply to individual projects or programmes relating to work required to address deterioration on the network or to prepare to mitigate or respond to high-impact low-probability events.

Assessment of components of forecast ARR expenditure

B35 We have assessed the reasonableness of proposed ARR expenditure with a particular focus on those with elevated levels of ARR compared to historical periods to test the justification for possible increases in this capex category.

B36 Firstgas Distribution revised its ARR capex forecast up by 38% ($5.1m) in its 2025 AMP compared to the 2024 AMP update, despite a 20% reduction in total capex (primarily driven by a drop in consumer connection expenditure).

B37 According to its 2025 AMP, Firstgas Distribution's ARR capex is largely driven by its pre-85 PE pipe replacement programme and the need to address emergent leaks. While Firstgas point to changes in its ARR strategy and using opex solutions where appropriate, it did not fully explain the underlying driver of the 38% increase from the 2024 to 2025 AMP.

B38 In its 2024 AMP Update, Powerco included a range of resilience mitigation projects in its capital expenditure forecasts.[66]

[66] Powerco "2024 Gas Asset Management Plan Update" (2024), Section 2.4 pp.9-19.

B39 We requested further information from Powerco about its resilience capex programme using a Request for Information, including:

B39.1 how much Powerco was seeking to spend, and when, on resilience risk mitigation measures over the next 10 years; and

B39.2 a list of all proposed projects including the capex for each.

B40 Powerco responded to our RFI request and reiterated that its latest resilience plan was consistent with the information set out in its 2024 AMP Update. Powerco stated that its 10-year resilience capex plan was forecasted at $1.9 million per annum from RY26, totalling $15 million over 8 years.

B41 While Powerco has risk exposures, our view is it has yet to calculate whether its forecast expenditures for resilience are justified at this stage. To justify resilience expenditures, Powerco should estimate the cost of the resilience risks manifesting on an annualised basis to test whether mitigations are cost effective.

B42 This analysis supports the reduction in ARR compared to Powerco AMP forecasts.

B43 We note the GasNet average is particularly impacted by the timing of delivery its investment programme which has resulted in a low 2024 value, and a high 2025 anticipated value. When this is taken into account GasNet are still forecasting slightly elevated levels compared to historical values.

B44 GasNet's AMP reflects the focus of ARR is on the continuing replacement of metallic pre-natural gas low pressure assets consistent with its traditional focus of ARR. We have not identified a clear driver to support an increase in expenditure beyond existing levels.

Expectation of increased capex-opex trade-off

B45 A broader overview of our approach to capex-opex trade-off is contained within Attachment C – Forecasting operating expenditure. This section covers the trade-off as it specifically relates to ARR capex.

B46 In its 2025 AMP, Vector states that it has introduced significant capex-opex trade-offs in its consideration of ARR capex, some of which is reflected in the significant reduction in ARR capex compared to its 2024 AMP update over the DPP4 period.

B47 Vector has provided a clear risk-based investment strategy and has explained and quantified the changes in its 2025 AMP with supporting information provided in response to our expenditure RFI.[67]

B48 Other GDBs are considering these trade-offs but have not clearly identified where they are being made and the dollar amounts they affect.

[67] Vector response to 'RFI2 – Expenditure' (May 2025), pp.5-7.

B49 When asked about the capex-opex trade-offs it is making, Powerco responded that improved condition data and revised leak tolerance thresholds had allowed it to prioritise repair and defer capex for pipe replacements.[68] It gave an example of a $1.2m per annum deferral of capex for its Knights/Wilford project. However, it did not offer a clear account of the total ARR capex that was shifted to operating costs.

B50 GasNet did not respond to our expenditure RFI.

B51 Although we have some information from GDBs about the capex-opex trade-offs they are considering over DPP4, we have not generally been able to establish a clear link between changes in opex levels and ARR capex forecast.

Setting GDB consumer connection capex allowances

Summary of our draft decision

B52 Our draft decision is to cap consumer connection capex at the lower of AMP forecast net of capital contributions or 20% of gross consumer connection capex, assessed individually for each year of the regulatory period. Table B3 sets out our expenditure analysis conclusions in this capex category.

Table B3 Consumer connection forecasts and draft decision allowances ($000's 2025)

GDB	GDB forecast	GDB Draft allowance	Reduction
Firstgas Distribution	862	574	288 (33%)
GasNet	605	121	484 (80%)
Powerco	12,410	3,062	9,348 (75%)
Vector	0	0	0 (0%)

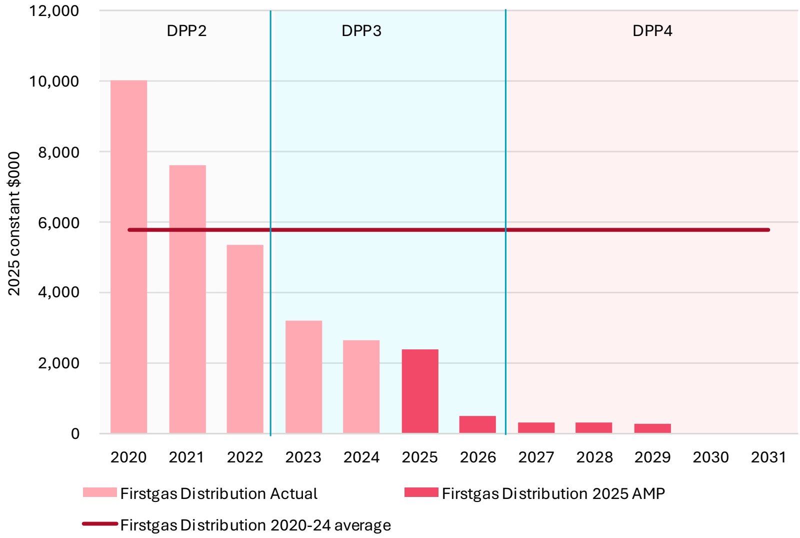
Background and analysis

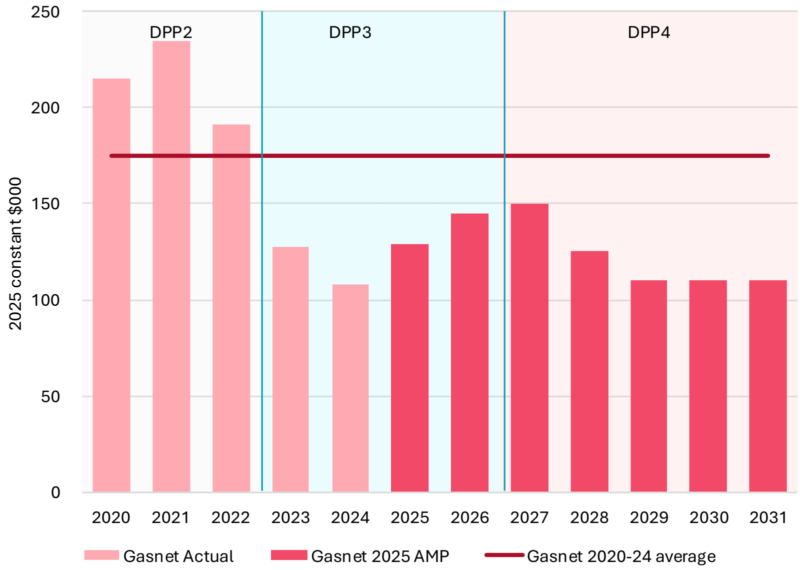
B53 Powerco, Firstgas Distribution, and GasNet have included forecasts for consumer connection capex net of capital contributions over DPP4 in their 2025 AMPs. While Vector is forecasting some growth capex, its capital contribution policy is that 100% of these costs are to be recovered from capital contributions.[69]

B54 Our analysis indicates that Firstgas Distribution, GasNet, and Powerco (see Figure B4) have all had declining consumer connection capex over DPP3, reflecting lower-than-forecast consumer connection volumes and increasing levels of capital contributions (Firstgas Distribution).

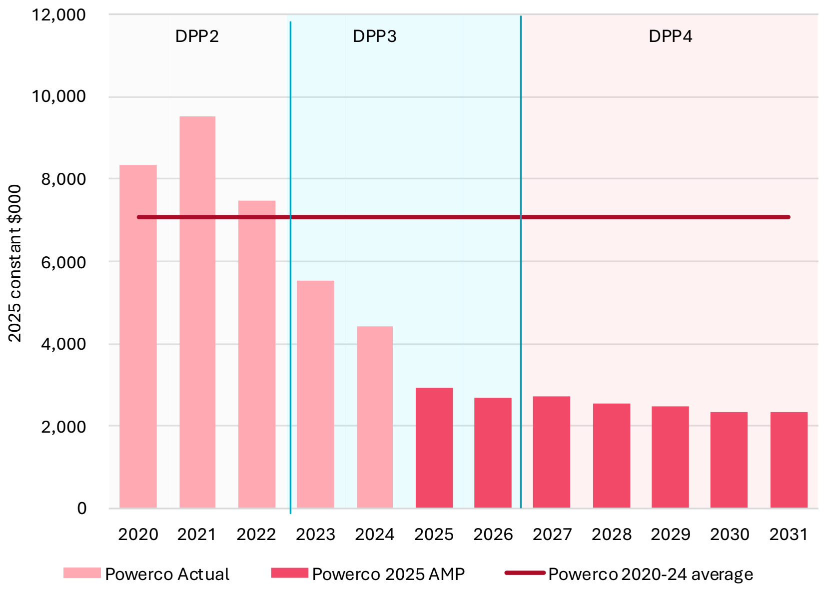
[68] Powerco response to 'RFI2 – Expenditure' (May 2025), pp.6-7.
[69] Vector, Policy for determining capital contributions on Vector's gas distribution network, 1 May 2025, para 4.1(a).

Figure B4 GDB consumer connection capex forecast and actuals ($000's 2025)[70]



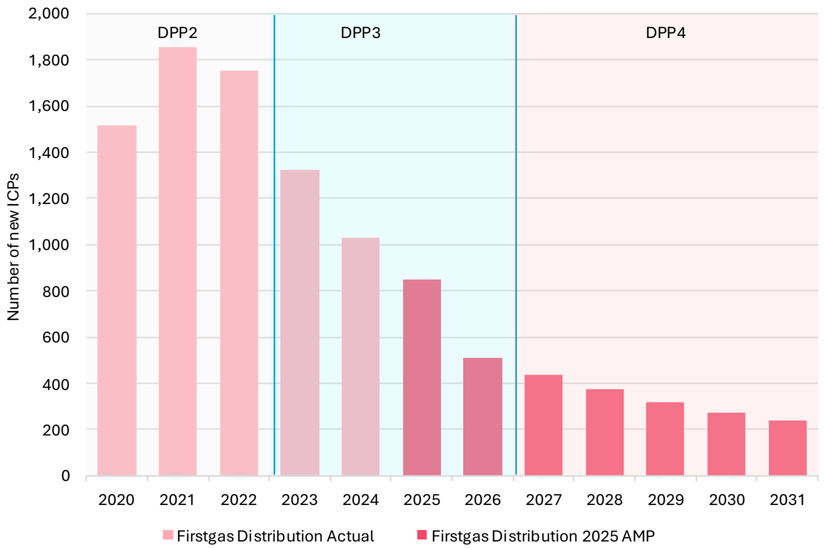


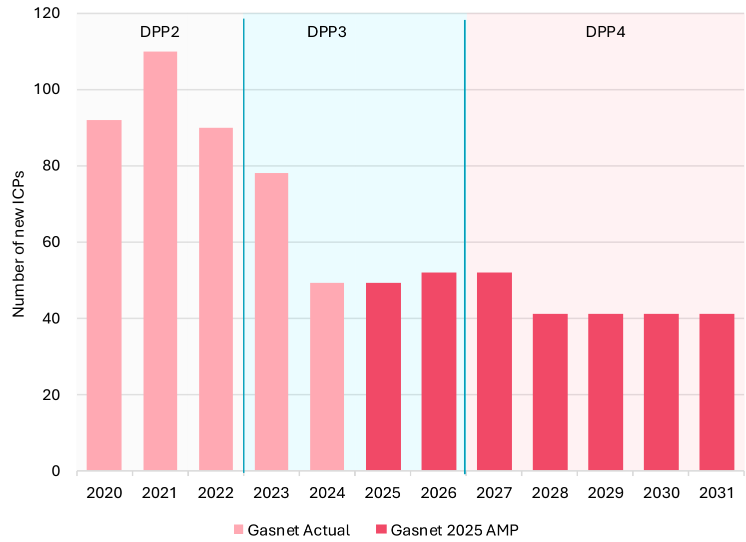
[70] Values are presented net of capital contributions.



B55 We compared the annual number of new ICPs since 2020 and what GDBs are forecasting out to 2031 (see Figure B5).

Figure B5 GDB new ICPs forecast and actuals





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Number of new ICPs
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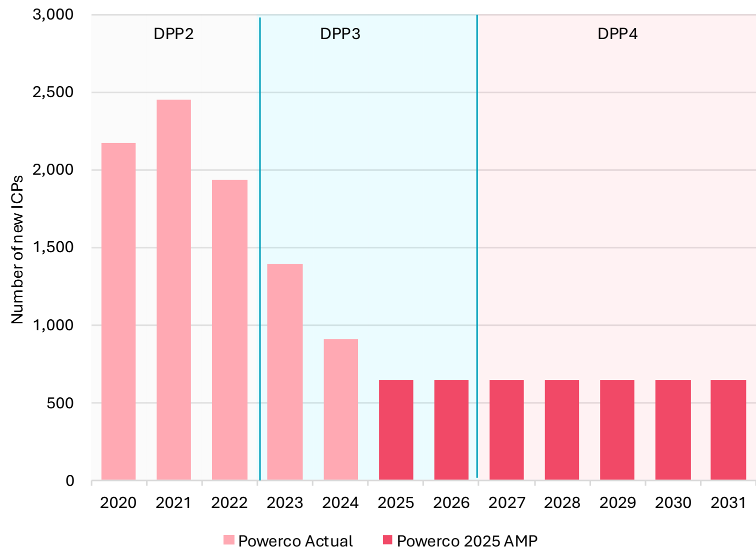
Gasnet Actual
Gasnet 2025 AMP



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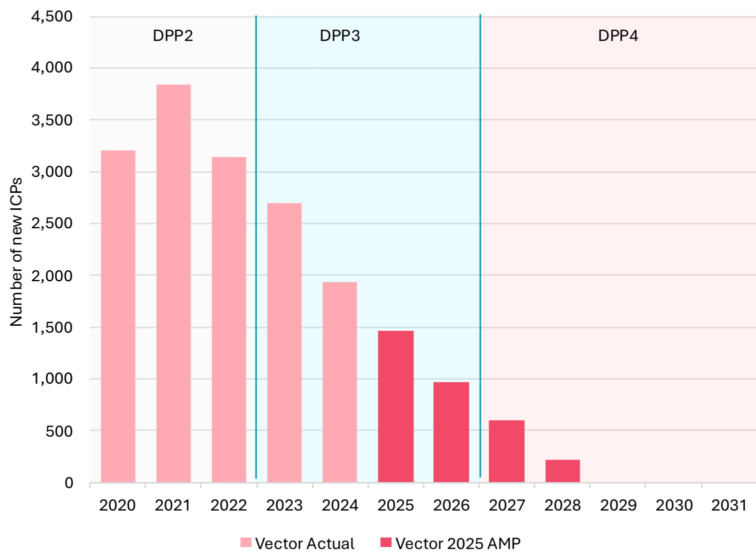
Powerco Actual
Powerco 2025 AMP



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Number of new ICPs
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Vector Actual
Vector 2025 AMP

B56 In its 2025 AMP, Powerco explained its ICP forecast by saying it considers the current decline in new ICPs to be a reflection of a slower economy causing a drop in new subdivision development but anticipates a decreasing Official Cash Rate (**OCR**) will mean a rise in residential developments and a stabilisation of the number of new connections in future.[71]

B57 Firstgas Distribution's 2025 AMP forecast follows a trajectory that more closely reflects the historical trend in new ICPs, stating:[72]

> We are projecting a 50% initial drop in consumer connection volumes from FY25 levels, with further declines expected due to weakening demand and planned changes to our capital contributions policy. We anticipate capital contributions will rise to 70–100% during DPP4 (pending policy changes).

B58 Firstgas Distribution attributes the decline in connection volumes to a downturn in building consents and reduced connection rates driven by uncertainty around the future of gas supply. Supply uncertainty is not explicitly acknowledged in Powerco's connections outlook.

B59 We also looked into GDB capital contribution rates forecast over DPP4. Table B4 highlights that Powerco and GasNet are setting capital contributions significantly lower than Firstgas and Vector.

Table B4 GDB forecast capital contribution rates over DPP4

GDB	Capital contribution as a proportion of connection cost
Firstgas Distribution	80%
GasNet	0%
Powerco	19%
Vector	101%

B60 In our Issues paper, we signalled that we would be seeking clarity on how GPBs assess the costs and benefits of new connections, manage asset stranding risks, and determine when capital contributions are in the long-term interests of consumers.

B61 Powerco's submission emphasised the importance of maintaining cost-sharing across a broad customer base and cautioned against rigid capital contribution policies. However, it did not provide supporting evidence of how it assesses whether new connections are beneficial to the existing customer base. This limits our ability to evaluate the robustness of its consumer connection capex forecast.

[71] Powerco" 2025 Gas Asset Management Plan" (2025), pp.16-17.
[72] Firstgas Distribution "Asset Management Plan" (30 September 2025), p.iii, p.17.

B62 We conducted analysis using disclosed information, to try and ascertain if GDB consumer connection capex subsidies were financially beneficial to the existing customer base by comparing the revenue returns of new connections with the costs. However, our analysis was inconclusive.

B63 Over the past 10 years, GasNet and Powerco's capex per new connection has remained relatively stable, while Firstgas' has decreased significantly, improving the likelihood that new connections recover their upfront costs. We acknowledge that there may be different underlying drivers across the networks which may be driving the difference in practice.

B64 The reduction in Firstgas' connection capex may reflect a change in its capital contribution policy, a shift in the types of customers connecting, efficiency improvements in its connection delivery model, or a combination of these factors.

B65 While we were unable to definitively determine whether new connections are beneficial, based on the available information, we consider it is important to signal the practices we expect to see from GDBs, that net connection costs reflect a reasonable view of the likely economic life of the connection. Capital contribution requirements should result in an outcome where the net present value of revenues for new customers are expected to exceed their incremental cost, including the incremental value of commissioned assets.

Options we considered to set GDB consumer connection capex allowances

B66 We considered a number of options available to ensure that we set allowances that are consistent with likely new connections. These options were:

B66.1 allowing the GDB forecasts; or

B66.2 setting consumer connection capex at a reduced level:

B66.2.1 either to zero with the expectation that new consumers will fully pay for new connections; or

B66.2.2 at a fixed proportion of the proposed amount.

B67 This is consistent with submissions received which noted concerns with a move to full up-front contribution requirements.

B68 In particular MGUG highlighted concerns with a requirement of full up-front capital contributions:[73]

> For GDBs we maintain that CAPEX allowances should be maintained to incentivise for connection growth on existing networks. The general policy for free connection service, if the connection is within 20 m of a residential property strikes a good balance between sharing public and private benefit and costs. As we highlight further, GDBs and consumers benefit from connection growth and having policies that require new

[73] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), p.3

connections to be fully funded upfront by the applicant is an important disincentive for growth

B69 Powerco also identified that capital contributions needed to balance risk and response:[74]

> While we agree with the Commission that new connections can contribute to stranding risk, new connections can also benefit the existing customer base as there are more customers to spread costs across. We are concerned regulatory intervention which disallows connection capex and requires 100% capital contributions, may force a market outcome e.g. trigger a death spiral for gas pipelines, as it's likely customers will be less willing to connect, at a time when there is still benefit in having new customers connect. A customer contribution level shouldn't be 0% or 100% but something in between that balances risk and response.

B70 We have decided to cap consumer connection capex at the lower of the AMP forecast net of capital contributions or 20% of gross consumer connection capex, assessed individually for each year of the regulatory period.[75]

B71 While we acknowledge this approach is imprecise, we are seeking to incentivise GPBs to assess whether or at what level of capital contributions will ensure that the incremental revenue from new connections will exceed the incremental cost, recognising that consumer connection expenditure which meets this standard will be in the long-term interests of consumers.

Setting GDB system growth capex allowances

B72 Our draft decision is to reject all system growth expenditure on the basis that demand forecasts and sector growth trends do not support the investment need.

Background and analysis

B73 System growth capex covers expenditure on assets where the primary driver is a change in demand on a part of the network which results in a requirement for either:

B73.1 additional capacity to meet this demand; or

B73.2 additional investment to maintain current security/quality of supply standards due to increased demand.

B74 Table B5 sets out the GDB system growth forecasts over DPP4 and Figure B7 shows historical system growth capex from 2020 and forecast system growth capex out to 2031.

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[74] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 13

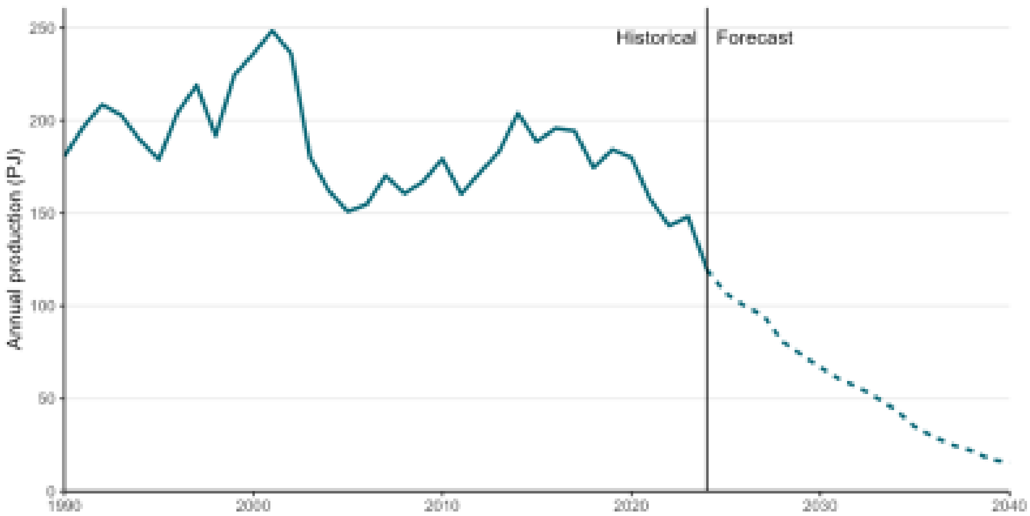
[75] In our expenditure forecast and financial modelling, capital contributions in constant $'s for 2031 are based on historical ratios rather than the 2025 AMP total capital contribution amount. If GPBs want to update us with 2031 capital contributions at a category level, they can provide this in their draft decision submissions.

Table B5 GDB system growth forecasts over DPP4 ($000's 2025)

GDB	GDB forecast	GDB Draft allowance	Reduction
Firstgas Distribution	1,289	-	1,289 (100%)
GasNet	275	-	275 (100%)
Powerco	4,322	-	4,322 (100%)
Vector	0	-	0 (0%)

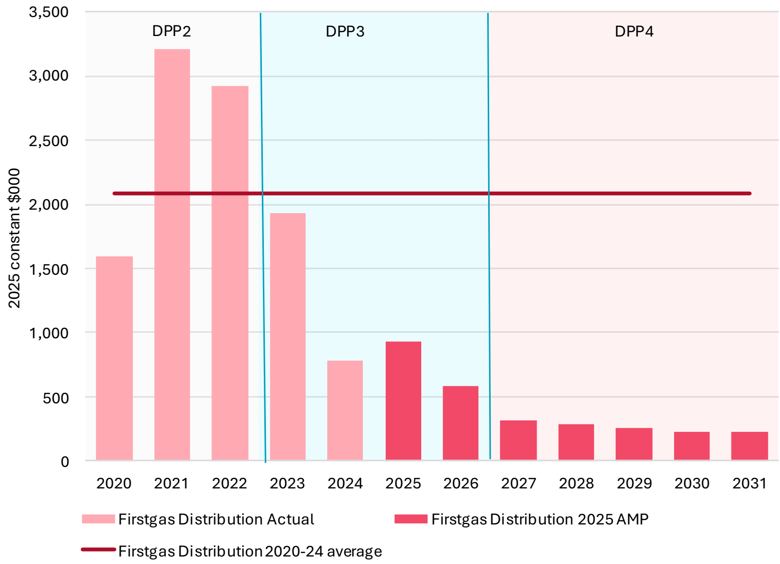
B75 All GDBs are forecasting a decline in some or all indicators of demand (total ICPs, maximum daily and monthly loads, total gas conveyed) over the DPP4 period; this is inconsistent with an increase in network capacity. MBIE's analysis of New Zealand's energy supply highlighted declining gas production.[76]

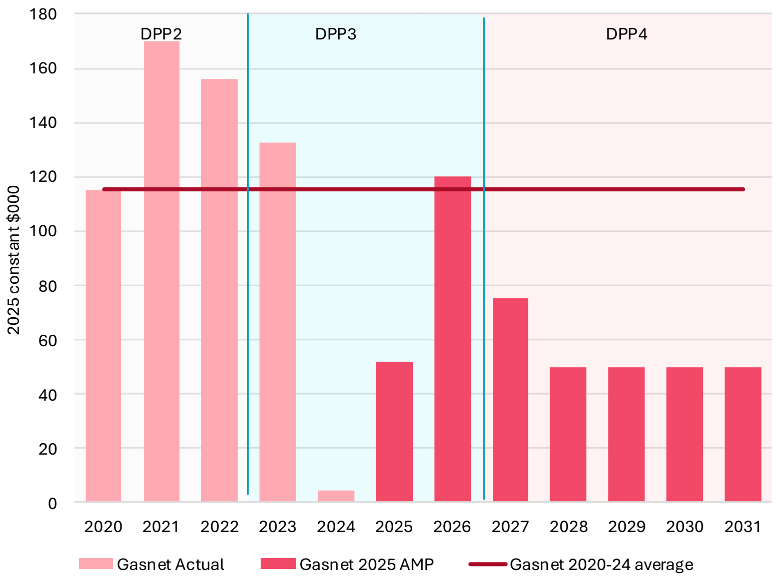
Figure B6 MBIE gas net production and forecast production

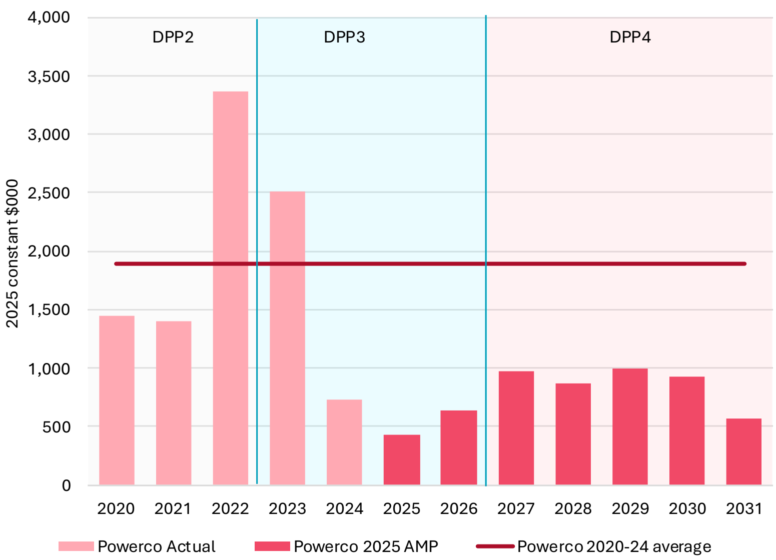


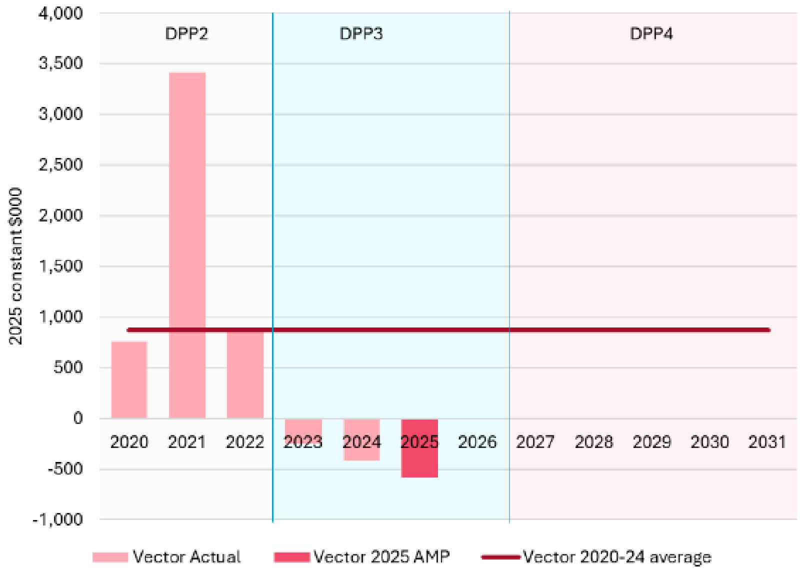
[76] MBIE, Energy in New Zealand 25, pages 28-29, available here.

Figure B7 GDB system growth capex forecast and actuals ($000's 2025)









B76 We reviewed Firstgas Distribution and Powerco's AMPs to understand what was driving their system growth forecasts.

B77 Firstgas Distribution explains in its 2025 AMP it is reviewing its approach to system growth and subdivision reticulation, with plans to implement significant changes during DPP4. Its aim is to ensure new developments, particularly residential subdivisions, contribute more equitably to network expansion, reducing stranded asset risk and protecting existing customers.[77]

B78 We also sought additional information about Powerco's proposed renewable gas expenditure through an RFI, requesting the range of projects, locations and intended investments. Powerco responded:[78]

> Our 2024 AMP update includes a placeholder for investment in renewable gas growth opportunities ($150k from RY28), such as extending our network to connect with renewable gas sources like biomethane facilities. We are signalling an increase because we anticipate there may be a need to build and connect to biogas facilities, but it is inherently uncertain and we do not have any detailed plans or projects at this time.

B79 Powerco noted:[79]

> We have not yet worked out how the costs between the connecting project/party and the existing customer base, this will be determined once we have progressed further in our thinking.

[77] Firstgas Distribution "Asset Management Plan" (30 September 2025), p.18.
[78] Powerco response to 'RFI2 – Expenditure' (May 2025), p.2.
[79] Powerco response to 'RFI2 – Expenditure' (May 2025), p.2.

B80 While it may be reasonable for Powerco to forecast this expenditure as it would be considered regulated assets, we are not satisfied that the information of the cost, timing and the benefit to consumers demonstrates that this expenditure is in the long-term benefit of consumers. Accordingly, our draft decision is to reject this proposed expenditure.

B81 Following our analysis, and in view of the outlook for gas production, we do not consider it in the long-term interest of consumers to provide funding for system growth at this time.

B82 However, to mitigate the risk that rejected system growth expenditure is in fact needed over the DPP4 period, GDBs may apply for a capacity event reopener with a system growth driver, should better information become available.[80]

Setting GDB non-network capex allowances

Summary of our draft decision

B83 Our draft decision is to set non-network capex allowances based on the lesser of the historical average or the GDB AMP 2025 forecast amount.

B84 Table B6 sets out our expenditure analysis decisions in this capex category and Figure B8 shows historical non-network capex from 2020 and forecast system growth capex out to 2031.

Table B6 Non-network capex forecasts and draft decision allowances ($000's 2025)

GDB	GDB forecast	GDB Draft allowance	Reduction
Firstgas Distribution	1,068	1,068	3,796 (21%)
GasNet	600	531	69 (11%)
Powerco	11,036	10,393	642 (6%)
Vector	8,850	8,850	0 (0%)

Background and analysis

B85 Given the unpredictable nature of non-network capex in comparison to network capex, we asked GDBs to provide more detailed explanation for the key projects forecast in the DPP4 period – including any available cost benefit analysis and alternatives considered using an RFI.

[80] Powerco has earmarked additional system growth expenditure (a local increase) to connect renewable gas projects up to its network over DPP4. Powerco response to RFI2.

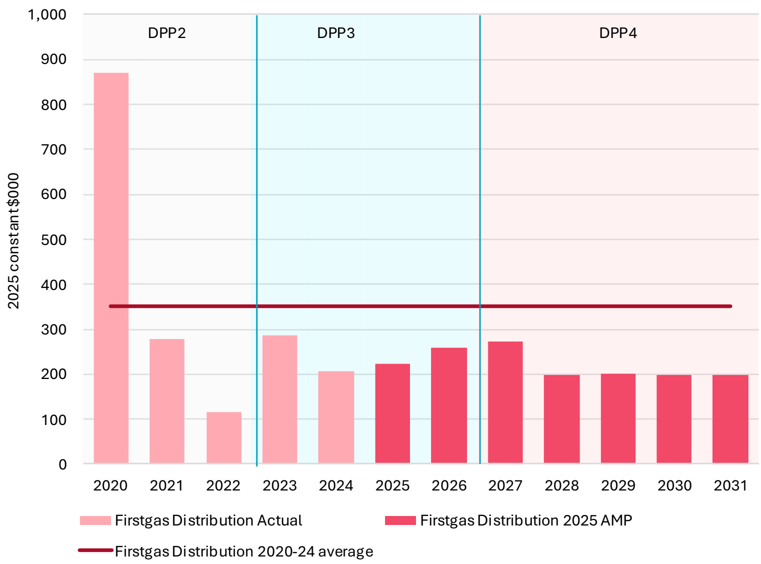
B86 Powerco stated that it doesn't have fully developed justifications for projects five years in the future whereas Vector and Firstgas provided detail on near term projects and estimates for other projects planned for later in the DPP4 period.

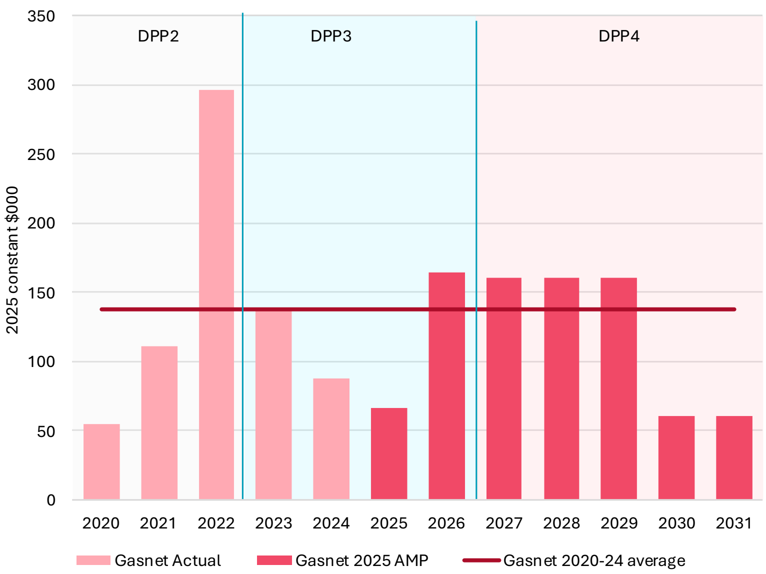
B87 Vector was able to provide business cases for projects closer to the implementation phase including those related to data centre relocation, Enterprise Resource Planning (**ERP**) system modernisation and gas remote monitoring unit replacement.

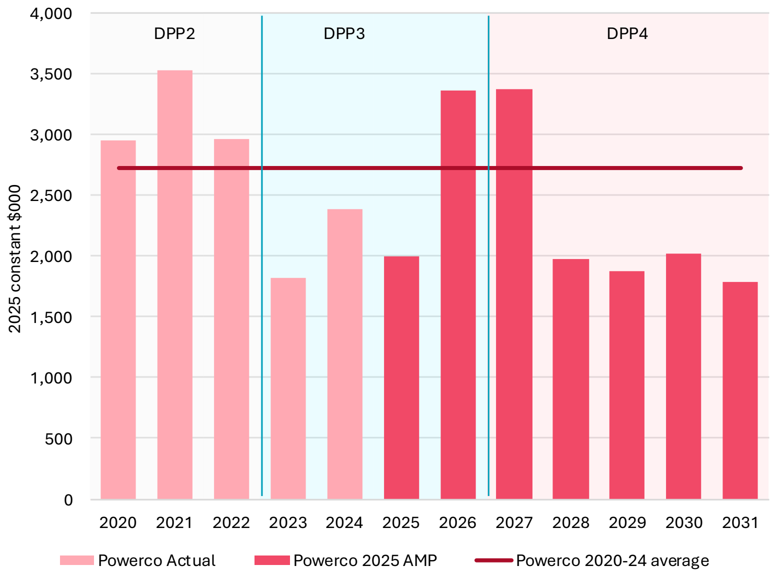
B88 We were not able to identify any expenditure that warranted further scrutiny in this capex category and were generally satisfied the information and explanations for expenditure supported it was prudent and efficient and in the long-term interest of consumer.

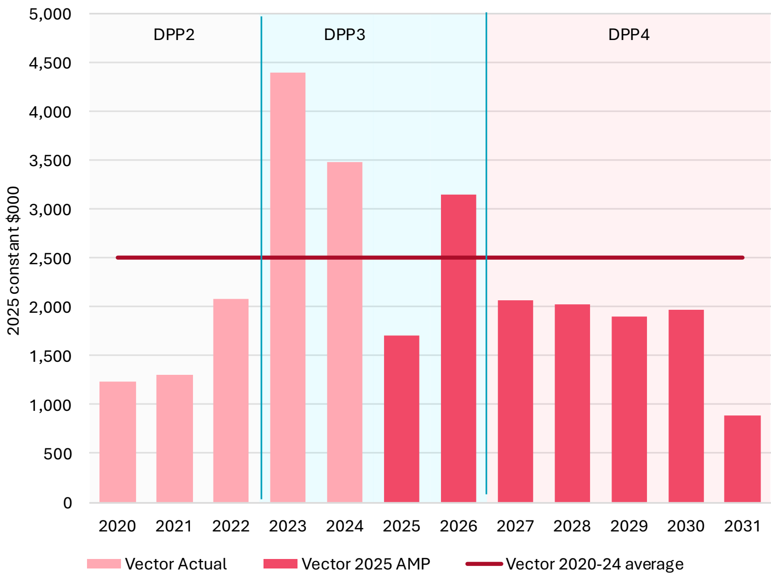
B89 Following our review of AMP and RFI material, we decided to set non-network capex allowances as the lesser of the 5-year historical average or the forecast amount from the 2025 AMP, assessed individually for each year of the regulatory period.

Figure B8 GDB non-network capex forecast and actuals ($000's 2025)









Setting reliability, safety and environment expenditure

B90 Our draft decision is to set RSE allowances based on the lesser of the historical average or the GDB AMP 2025 forecast amount, assessed individually for each year of the regulatory period.

B91 Table B7 sets out our expenditure analysis decisions in this capex category and Figure B9 shows historical non-network capex from 2020 and forecast system growth capex out to 2031.

Table B7 Reliability, safety and environment forecasts and draft decision allowances ($000's 2025)

GPB	GPB forecast	GPB Draft allowance	Reduction
Firstgas Distribution	2,146	1,384	762 (35%)
GasNet	375	375	0 (0%)
Powerco	5,238	5,238	0 (0%)
Vector	1,287	1,287	0 (0%)

Background and analysis

B92 Firstgas Distribution is the only GDB forecasting higher than historical average RSE expenditure over the DPP4 period (55% increase) in its 2025 AMP.

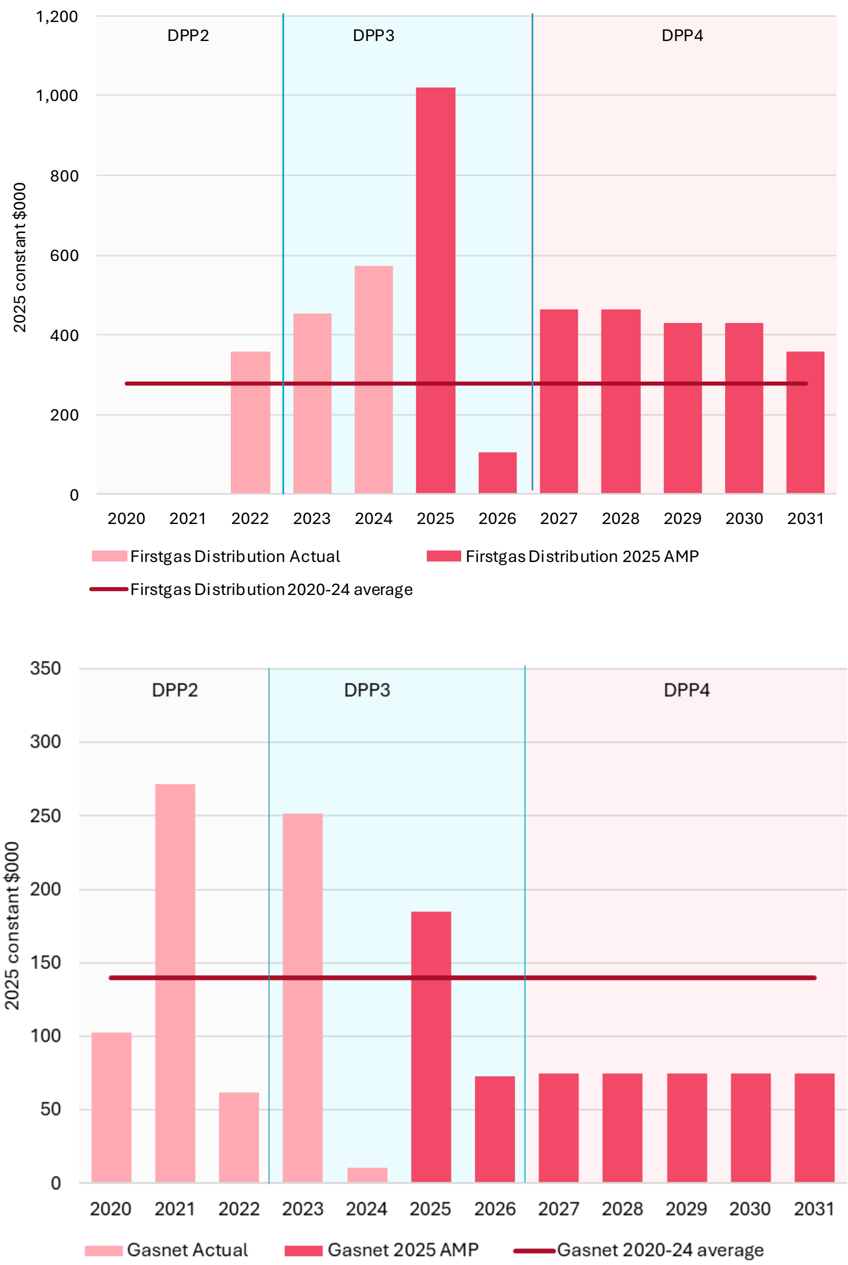
B93 Vector which previously had more elevated levels of RSE expenditure has reduced its forecast from both its levels in its 2024 AMP and against historical levels citing a review of strategic valve requirements and the redirection of capital investment to operational expenditure.

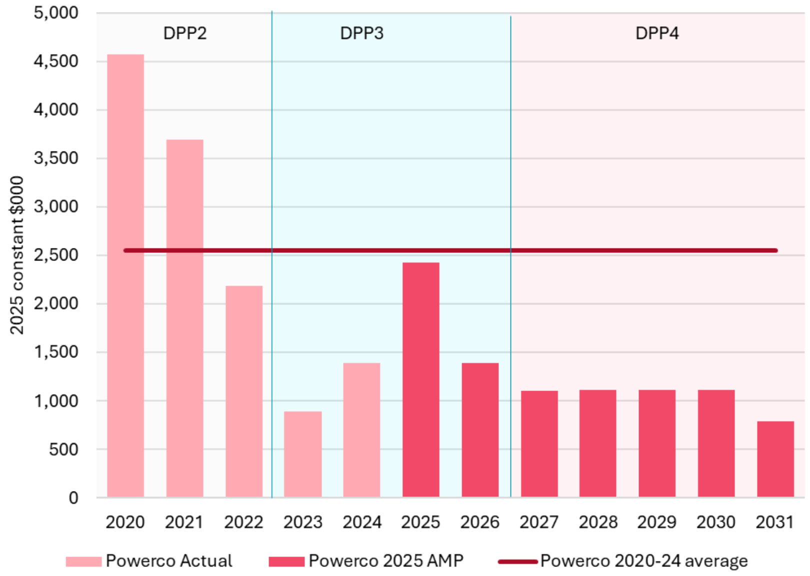
B94 Firstgas Distribution has stated its RSE expenditure forecast is driven by the need to meet the latest standards for fire values on district regulator stations with the increase in expenditure following a reprioritisation of expenditure following a change in strategy for the Pre75 and Pre 85 pipes.

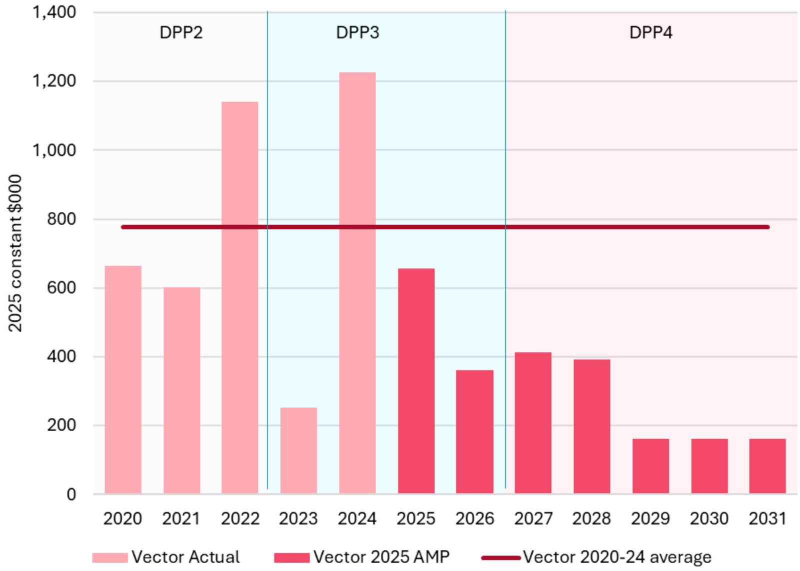
B95 We have not specifically reviewed this investment but note the reprioritisation of other capex has not resulted in a decrease in the level of forecasted ARR capex compared to historic levels.

B96 Following our review of AMP and RFI material, we decided to set RSE capex allowances as the lesser of the 5-year historical average or the forecast amount from the 2025 AMP, assessed individually for each year of the regulatory period.

Figure B9 GDB RSE capex forecast and actuals ($000's 2025)







Setting Firstgas Transmission's capex allowance

Summary of our draft decision

B97 Table B8 sets our expenditure analysis draft decision for Firstgas Transmission.

Table B8 GTB capex forecast and draft decision allowance ($000's 2025)

GTB	GTB forecast	GTB Draft allowance	Reduction
Firstgas Transmission	163,925	157,908	6,017 (4%)

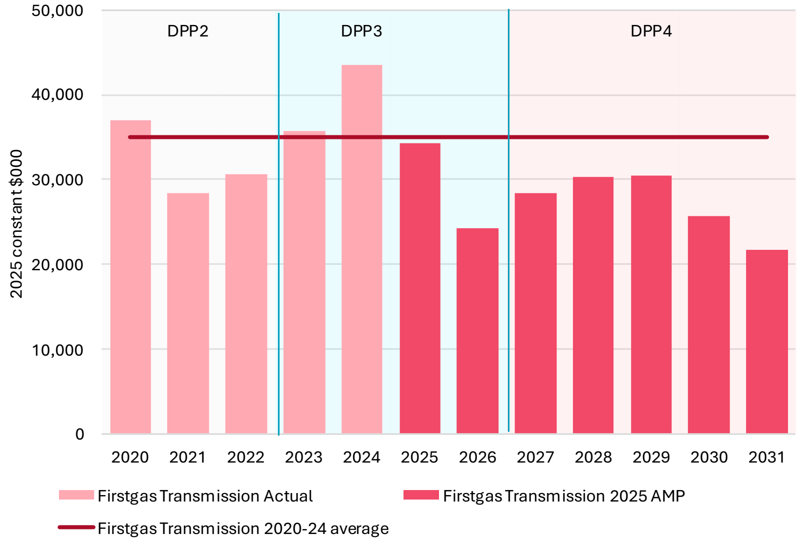
B98 Firstgas Transmission's capex forecast over the DPP4 period is primarily driven by asset replacement and renewals capex (85%) followed by non-network capex (11%) and minor levels of system growth, RSE and asset relocations (principally covered by capital contributions).

B99 We focussed our analysis on ARR capex, asking for further information on capex-opex trade-offs, non-network capex and RSE capex through RFIs.

GTB asset replacement and renewals capex

B100 Analysis of historical and planned expenditure reveals that the GTB network capex is dominated by expenditure for asset replacement and renewals (84% of spend both historical and planned across DPP3 and DPP4) of the total capex. Figure B10 below shows the comparative of historical ARR capex compared to forecast and Figure B1 and Figure B2 earlier in the paper shows the by capex category split.

Figure B10 GTB asset replacement and renewals capex forecast and actuals ($000's 2025)



B101 Firstgas Transmission is forecasting a decline in both total capex and ARR capex in its 2025 AMP, with total capex at 86% and ARR capex at 93% of the levels forecast in its 2024 AMP over the same period.[81]

B102 To better understand the ARR forecast we asked Firstgas Transmission through an RFI about its approach to capex/opex trade-offs to ascertain how it was taking shortened asset lives into its asset replacement and renewals decision making.[82]

B103 Firstgas Transmission responded that, in light of significant uncertainty surrounding the future of the transmission system, the business had adopted a more nuanced approach to investment planning. Rather than making binary decisions between opex and capex, it evaluates a range of solutions that balances risk reduction, cost-effectiveness, and asset longevity.[83]

[81] Firstgas Transmission "Asset Management Plan" (30 September 2025), Firstgas Transmission "Asset Management Plan Update" (30 September 2024)

[82] Commerce Commission "Gas DPP4 RFI2 Expenditure – Firstgas Transmission" (May 2025).
[83] Firstgas Transmission response to 'RFI2 – Expenditure' (May 2025), p.1.

B104 This is particularly evident in decisions around long-life assets like pipelines and compressors, where shorter-term, lower-capex options are increasingly favoured due to the risk of asset stranding, noting that:[84]

> There is increasingly a need to look at the return on investment of CAPEX investment to replace the units on an ever shorter horizon, against the compromise of accepting an ever increasing inspection and maintenance programme (OPEX) on the machines for the foreseeable future.

B105 Some of the reduction in ARR capex over time is driven by this change in its approach to assessing asset risk/cost trade-offs that inform capex and opex decisions.

B106 However, as its response indicates, these trade-offs are not recorded or reported as simple one-to-one substitutions in its asset management plans. This makes it difficult to quantify the extent to which ARR capex reductions are attributable to opex substitution. We discuss the opex substitution question in our opex analysis attachment (Attachment C).

B107 Firstgas Transmission is proposing ARR capex below average historical levels over DPP4. Our assessment of the information provided within its RFI response, which is a targeted subset of analysis and not a full review of all ARR projects, did not identify any ARR projects or programmes issues, in terms of uncertain costs or timing, that did not appear prudent and efficient.

B108 Our draft decision is to apply the same top-down approach used in DPP3 and allow the forecast real ARR capex if it does not exceed a projection of historical average real capex (see Figure B7). This has resulted in the acceptance of the 2025 AMP forecast amount for all periods given the significant decrease in ARR capex forecast compared to historical levels of expenditure.

GTB non-network capex

B109 Non-network capex includes information and technology systems, asset management systems, office buildings, tools, plant and machinery and other assets that are not network assets.

B110 The Firstgas Transmission non-network capex recent historical average is dominated by two large expenditure items (see Figure B11):

B110.1 the first, in DY2020, relates to costs incurred in relation to the Gas Transmission Access Code (**GTAC**) project IT systems; and

B110.2 the second, in DY2021, relates to the GTAC project being abandoned and capex costs in that year being written off and expensed as business support opex.

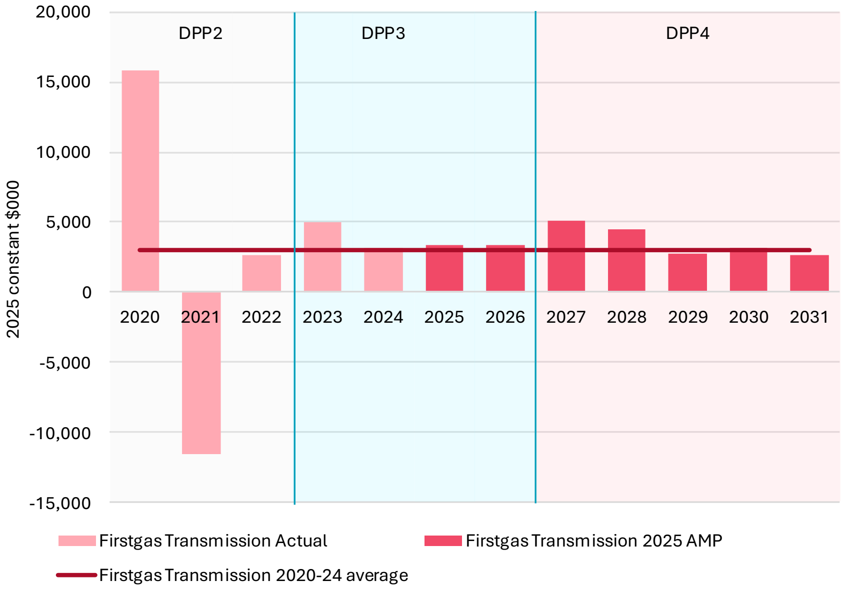
[84] Firstgas Transmission response to ‘RFI2 – Expenditure’ (May 2025), p.1.

B111 In its 2021 Information Disclosure, Firstgas Transmission stated that:[85]

> During FY2021, Firstgas decided not to proceed with the Gas Transmission Access Code (GTAC) implementation project due to challenges experienced with the project and changes in the external environment facing the gas sector. This decision is reflected in our financial and regulatory accounts for FY2021 through a negative CAPEX adjustment (removing costs from Work in Progress).

B112 While these large GTAC expenditures in DY2020 and DY2021 have appeared to distort the historical average between DY2020 and DY2024 above what would be considered an expected level of non-network capex, they balance out in the 2020 and 2021 disclosure years.

Figure B11 GTB non-network capex forecast and actuals ($000's 2025)



B113 Our analysis concluded that the Firstgas Transmission 2025 AMP forecast non-network capex is not inconsistent with the historical average. Consistent with our GDB non-network capex decision we have capped the DPP4 allowance at the historical average. Where the forecast amount is less than the historical average capex, we have set the allowance at the 2025 AMP forecast amount, assessed for each year of the regulatory period.

GTB reliability, safety and environment capex

B114 Firstgas Transmission's forecast RSE capex (see Figure B12) for DPP4 has decreased significantly from its 2024 AMP update and is expected to be lower than historical levels.

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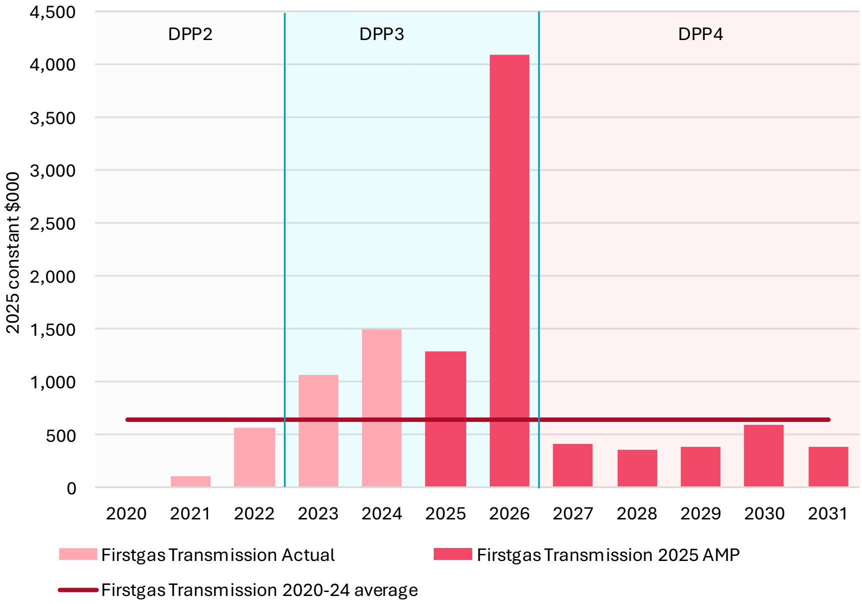
[85] Firstgas Transmission "Information disclosure for the gas transmission business" (30 September 2021) Schedule 14, Box 9.

Figure B12 GTB reliability, safety and environment capex forecast v actuals ($000's 2025)



B115 We requested information from Firstgas Transmission within an RFI on the key drivers of expenditure, our review did not identify any specific expenditure we assessed as unlikely to be required from a prudent and efficient operator.[86] Our draft decision is to accept the 2025 AMP forecast because it is lower than the historical average for each year of the regulatory period.

B116 Firstgas Transmission also has the opportunity to use the resilience capex reopener mechanism if it requires additional RSE capex, eg, to mitigate a resilience risk exposure.

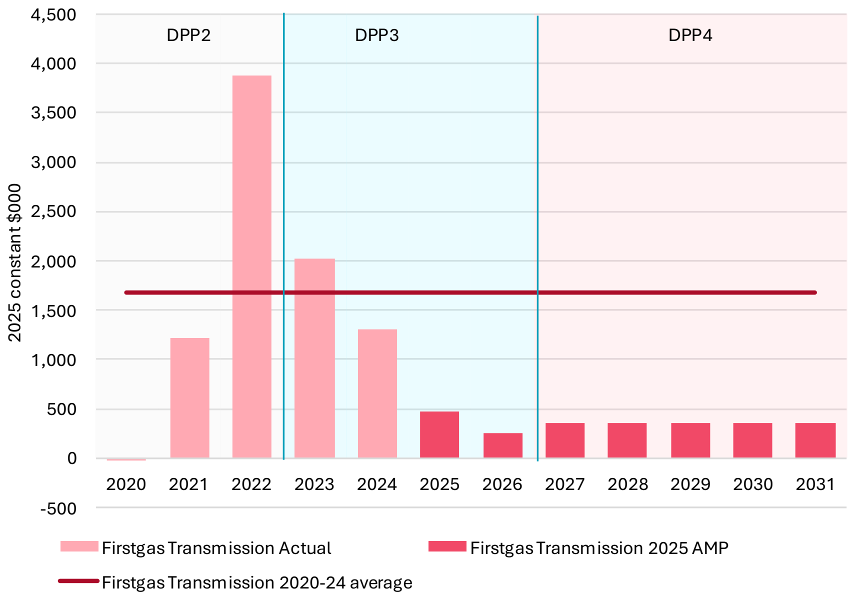
GTB system growth and consumer connection capex

B117 Firstgas Transmission has forecasted a small amount of system growth capex (see Figure B13) despite none of the GDBs projecting an increase in total ICPs or gas conveyed, Firstgas Transmission's own demand forecast signalling a decline in quantity of gas delivered,[87] and its 2025 AMP providing no information on the need for this investment.

[86] The Firstgas Transmission "Asset Management Plan" (30 September 2025) notes for the elevated level of expenditure in 2025 and 2026 (p34), this relates to reinforcing the network after optimising the sizing of compressor stations along the southern network, specifically from New Plymouth to Wellington and installing vehicle impact protection to safeguard aboveground assets from potential damage by out of control vehicles. Both initiatives remain on schedule for completion in FY26 and there is an expectation expenditure will normalise to historic levels.

[87] Firstgas Transmission "Asset Management Plan – AMP Appendices" (30 September 2025), Schedule 12B, p.13.

Figure B13 GTB system growth capex forecast v actuals ($000's 2025)



B118 Firstgas Transmission's 2025 AMP indicates some of this system growth forecast capex is earmarked for renewable gas blending opportunities.[88]

> Despite forecasting minimal system growth across the planning period, we have prudently made an allowance to accommodate potential blended gas opportunities should they emerge.

B119 Following our review, and consistent with our system growth capex draft decisions for GDBs, our draft decision is to not approve allowances for GTB system growth capex, on the basis that:

B119.1 the forecast expenditure is not consistent with sector growth projections; and

B119.2 that the forecast expenditure has not been justified.

B120 Firstgas Transmission is not forecasting any consumer connection capex over the DPP4 period.

Setting GPB asset relocations capex allowances[89]

Summary of our draft decision

B121 Our draft decision is to set asset relocations capex allowances based on the lesser of the historical average or the GPB AMP 2025 forecast amount, assessed individually for each year of the regulatory period.

B122 The level of asset relocation is inherently quite variable across periods given it is driven by third-party requests and is impacted by GPBs capital contribution policies

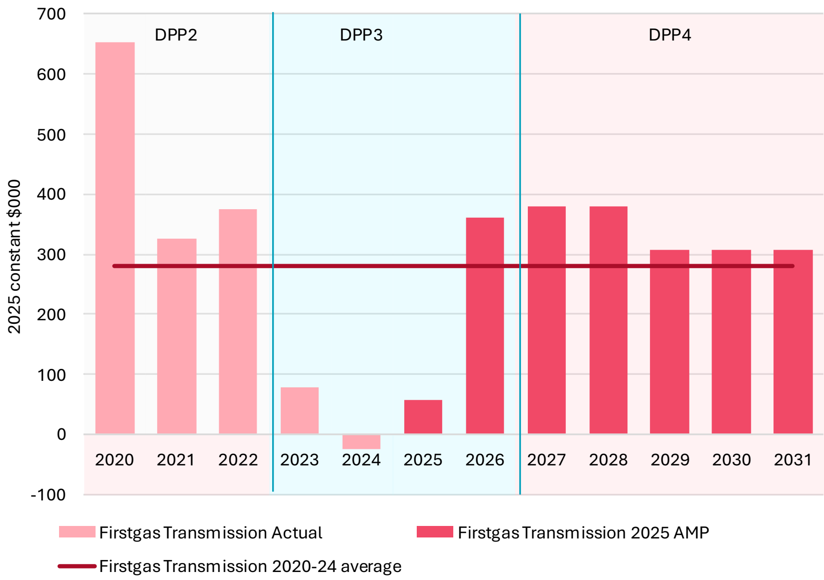
[88] Firstgas Transmission "Asset Management Plan" (30 September 2025), p.18.
[89] Values are expressed net of capital contributions

B123 Table B9 sets our expenditure analysis decisions in this capex category and Figure B14 shows historical asset relocations capex from 2020 and forecast system growth capex out to 2031.[90]

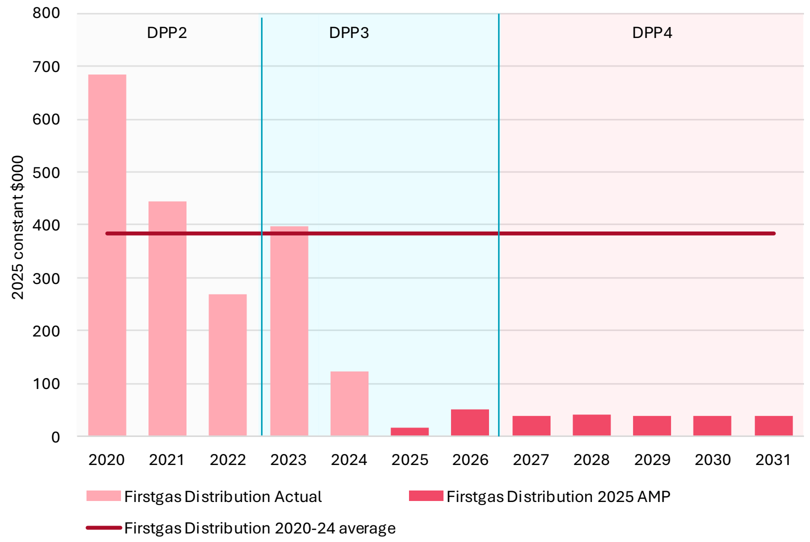
Table B9 GPB asset relocations capex forecasts and draft decision allowances ($000's 2025)

GPB	GPB forecast	GPB Draft allowance	Reduction
Firstgas Transmission	1,678	1,405	273 (-16%)
Firstgas Distribution	199	199	0 (-0%)
GasNet	50	50	0 (-0%)
Powerco	0	0	0 (0%)
Vector	1,155	118	1,037 (-90%)

Figure B14 GPB asset relocations capex forecast and actuals ($000's 2025)



[90] Note that Powerco is forecasting in its 2025 AMP to fully fund asset relocations using capital contributions. Powerco "2025 Gas Asset Management Plan" (2025)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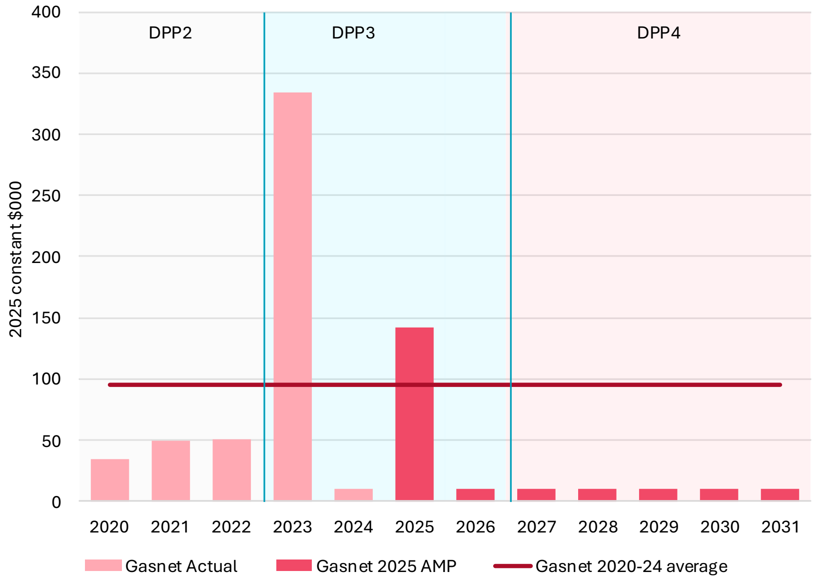
Firstgas Distribution Actual
Firstgas Distribution 2025 AMP
Firstgas Distribution 2020-24 average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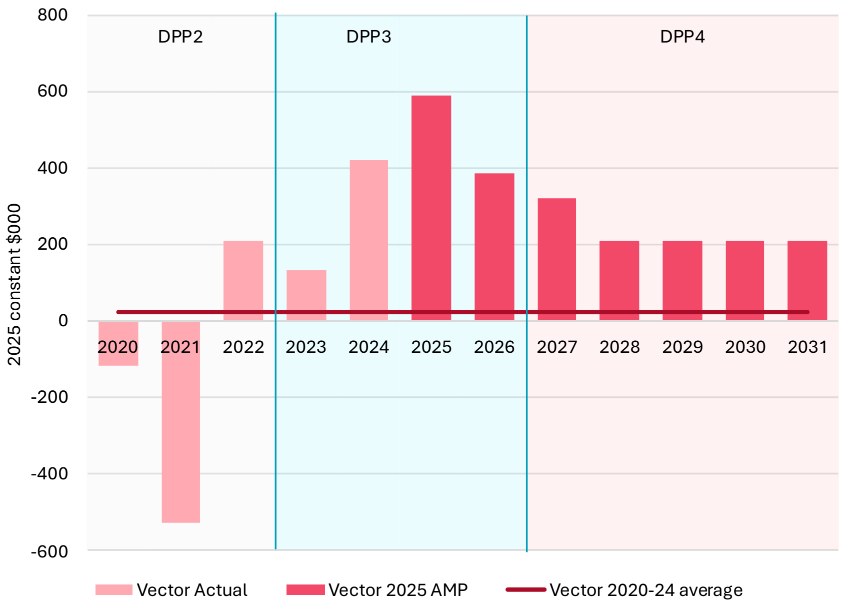
Gasnet Actual
Gasnet 2025 AMP
Gasnet 2020-24 average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Vector 2025 AMP
Vector 2020-24 average

Setting a value for cost of finance

B124 Our draft decision is to include an allowance for the cost of finance, scaled in proportion to the capex allowance in each expenditure category.

B125 AMP forecasts include the cost of financing expected to be accumulated during the construction of the planned work programme, ie, 'works under construction' or 'work in progress' (**WIP**).

B126 We have decided to retain the approach taken in past resets of including forecast cost of financing for each expenditure category when assessing AMP forecasts against the reference period. This means the cost of financing is scaled as part of the setting of the capex allowance. We are not aware of any reason to change our treatment of the cost of financing for DPP4.

B127 Our review of forecasted values for cost of finance did not identify any values which we considered may be unlikely to arise.

How we convert constant $2025 capex to nominal values,

B128 Our draft decision is to convert the capex forecast allowances into nominal values using forecasts for the Capital Goods Price Index (**CGPI**) with no adjustments.

B129 In DPP2 and DPP3 we used the New Zealand Institute of Economic Research's (**NZIER's**) most recent all industries Producer Price Index (**PPI**) inflator series to inflate capex.

B130 The PPI measures changes in prices for the supply (outputs) and use (inputs) of goods and services by New Zealand's productive sector.[91] It measures changes in the prices of outputs that generate operating income, and inputs that incur operating expense. The PPI does not include prices for items related to capitalised expenditure, nonoperating income, financing costs, or employee compensation. Nor does it cover depreciation, or income related to property ownership when this is not the normal source of operating income.

B131 Given that the PPI excludes capital expenditure we think it is less appropriate to use to escalate capex than CGPI.

B132 In electricity resets we have historically used CGPI because:

B132.1 it is the most dependable source of information about future changes in capital expenditure;

B132.2 it provides a good proxy for industry-specific indices; and

B132.3 industry specific indices are hard to forecast individually

[91] Commerce Commission "Gas DPP3 – Final -Expenditure (operating expenditure and capital expenditure) model" (31 May 2025), also used PPI.

B133 Recent trends show there has been higher than the average all sectors inflation in the Electricity, Gas, Water and Waste (**EGWW**) sector. In EDB DPP4, we made an adjustment to recognise inflationary pressures that we considered were likely to persist in the medium term.

B134 While we recognised that there may be higher inflation in EGWW for the EDB DPP4 reset, we do not think it likely that the GPBs have the same inflationary pressures on capital expenditure as the EDBs.

B135 In the context of growth in the electricity sector, there may be upward pressure due to global demand for equipment. We do not have evidence of the same inflationary pressures applying to gas as for electricity nor did we receive specific submissions providing evidence that inflationary pressures in electricity and gas are comparable.

B136 Accordingly, we are not proposing to apply an additional adjustment beyond CGPI for inflating capex to nominal terms.

Attachment C Forecasting operating expenditure

Purpose of this attachment

C1 This attachment outlines the rationale for our draft decision on setting opex allowances for Gas DPP4.

C2 This attachment sets out:

C2.1 a description of our approach to setting opex allowances for each gas pipeline business (**GPB**) for each year of DPP4 including consideration of Open letter and Issues paper submissions;

C2.2 our draft decisions for:

C2.2.1 use of base-step-trend (**BST**) approach to set opex;

C2.2.2 choice of base year;

C2.2.3 analysis of step changes requested by GPBs;

C2.2.4 trend factors applied; and

C2.2.5 escalators used in converting opex to nominal values; and

C2.3 setting the yearly opex allowances for each GPB as the lessor of its 2025 Asset Management Plan (**AMP**) forecast and BST modelling outcome.

C3 We have performed all opex analysis using historical and forecast expenditure in constant 2025 $. All expenditure in this attachment is expressed in constant 2025 $ prices unless stated otherwise.

Summary of draft decision including allowances

C4 Table C1 below summaries each GPB's 2025 AMP forecast, our draft decision opex allowance for each GPB and the difference between its AMP and DPP4 allowances in monetary value and percentage.

Table C1 Comparison of AMP forecasts to DPP4 allowances (constant 2025 $'000)

GPB	AMP forecast	DPP4 allowance	Difference to AMP forecast	DPP4 allowance to AMP forecast (%)
Firstgas Transmission	326,267	311,227	(15,040)	95%
Firstgas Distribution	68,530	63,678	(4,851)	93%
GasNet	13,558	12,889	(669)	95%
Powerco	104,892	99,870	(5,022)	95%
Vector	101,012	96,187	(4,825)	95%
Total	**614,259**	**583,850**	**(30,409)**	**95%**

C5 As a result of our analysis, we set DPP4 opex allowances at the lower of the BST modelling outcomes and their respective AMP forecasts for each year of DPP4. The aggregate total allowance for all individual GPB over the five-year DPP4 period is lower than their 2025 AMP forecasts

C6 Table C2 shows each GPB's yearly opex allowance and the total over the DPP4 period.

Table C2 DPP4 opex allowances by year (constant 2025 $'000)

GPB	2027	2028	2029	2030	2031	DPP4 Total
Firstgas Transmission	62,245	62,245	62,245	62,245	62,245	**311,227**
Firstgas Distribution	12,840	12,809	12,759	12,686	12,585	**63,678**
GasNet	2,599	2,588	2,578	2,567	2,556	**12,889**
Powerco	20,049	20,021	19,985	19,938	19,876	**99,870**
Vector	19,320	19,371	19,267	19,149	19,081	**96,187**
Total	**117,053**	**117,034**	**116,833**	**116,585**	**116,344**	**583,850**

C7 Figures C1 to C5 below shows graphically for each GPB, its historical actuals, AMP forecast and DPP allowances in the three regulatory periods.

Figure C1 Firstgas Transmission

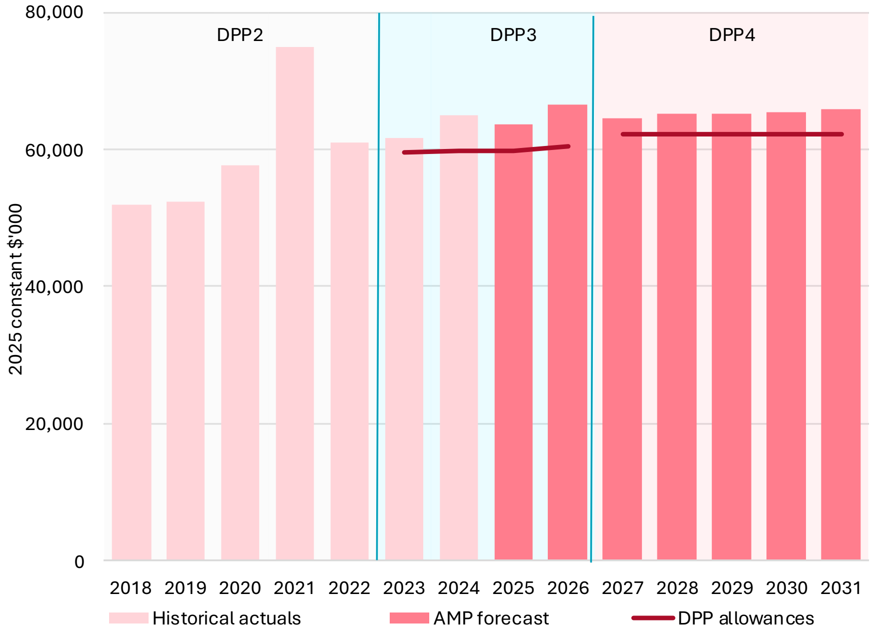


Figure C2 Firstgas Distribution

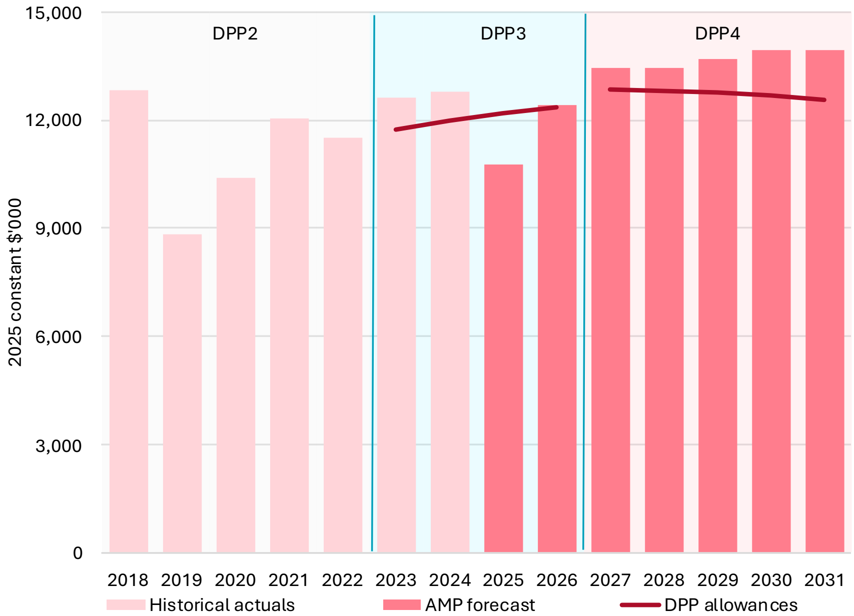


Figure C3 GasNet

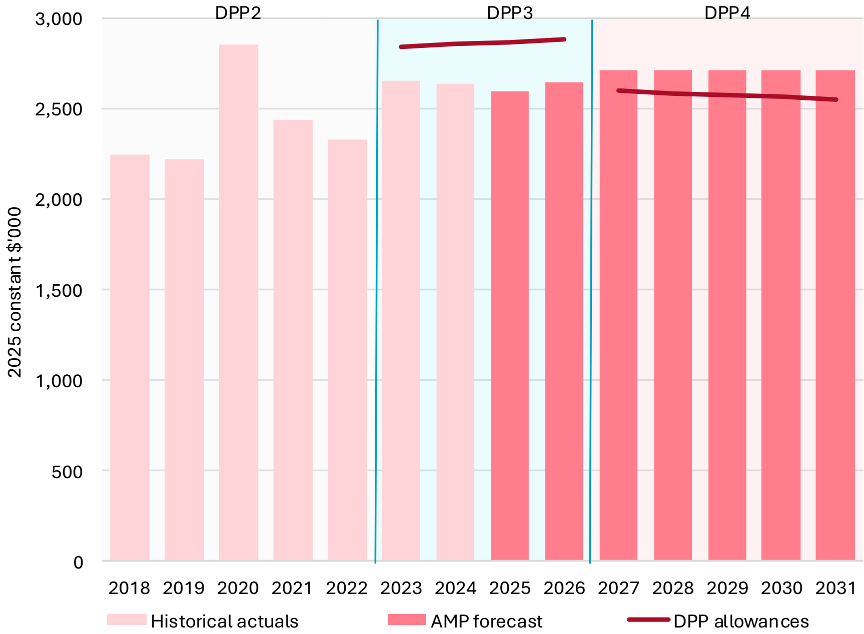


Figure C4 Powerco

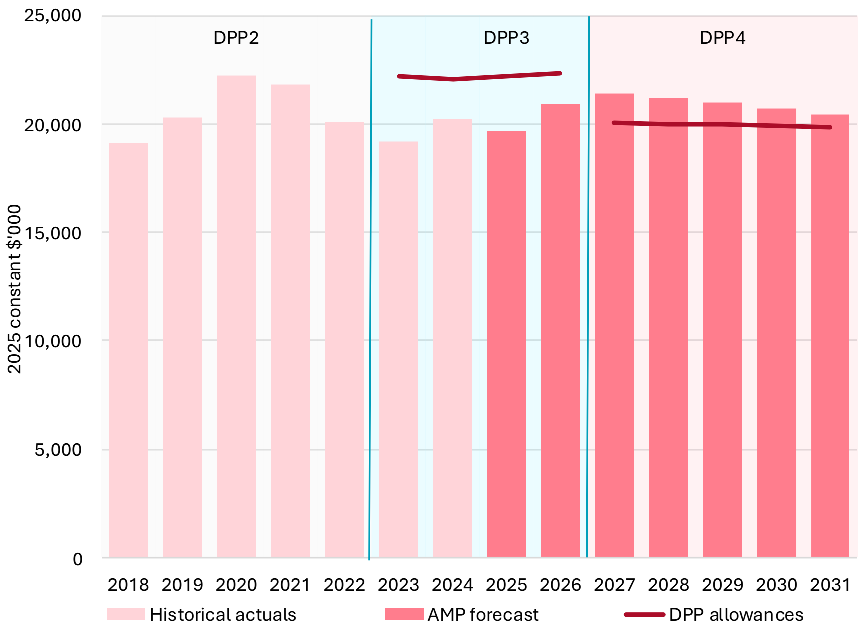
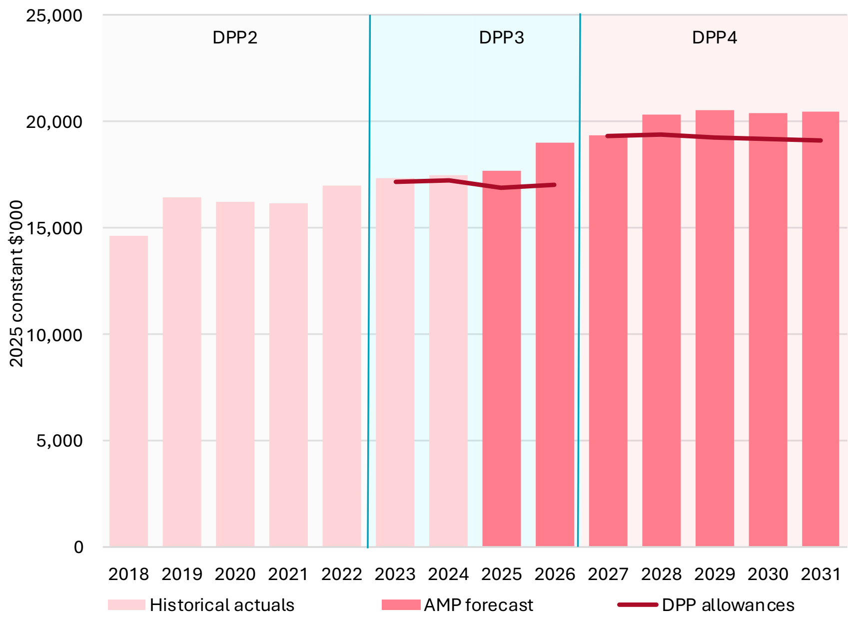


Figure C5 Vector



C8 We have used the BST modelling approach to test GPBs' AMP forecast and also a means of setting the DPP4 allowances.

How we are setting opex allowances for DPP4

C9 For this reset, we used BST modelling to forecast what a prudent and efficient GPB would be expected to spend over the regulatory period. We considered this modelling approach reflected the fact that opex is generally more predictable, as it largely comprises expenditure related to recurring activities, and the approach allowed us to model specific adjustments that affect each GPB.

C10 To better understand the drivers of opex forecasts we sought information within an RFI, on non-recurring costs, rationale for significant changes in levels of historic opex between years and capex/opex substitution.

C11 Once the information was available, we:

C11.1 used opex data from the most recently received disclosure year for all GPBs (being disclosure year 2024) to set an opex base value and made adjustments for non-recurring amounts;

C11.2 factored certain opex activities as step changes and made supplier-specific step changes where they were supported by evidence; and

C11.3 modelled opex trends using the following three main cost drivers:

C11.3.1 network scale – the scale of the network may affect operating expenditure as the volume of service provided changes;

C11.3.2 partial productivity – changes in operating efficiency will affect the amount of operating expenditure needed to provide a given level of service; and

C11.3.3 input prices – changes in input prices will affect the cost of providing a given level of service over time.

C12 Following our BST modelling, we compared our BST model outcomes against each GPB's AMP forecast for material differences, to determine whether we needed to undertake a targeted review of the GPB forecasts to understand these differences.

C13 Upon completing our analysis and review, we set opex allowances at the lesser of the BST model outcome and the supplier's AMP forecast for each year of DPP4

Stakeholder views on our approach to setting opex allowances for DPP4

C14 Submitters to our Open letter noted that there may already be a shift towards opex solutions in aggregate and we should consider how this can be facilitated through this reset.[92]

C15 In our Issues paper, we sought stakeholder views on what alternatives to the BST methodology could be used to test and scrutinise GPBs' forecasts.

Stakeholder submissions

C16 Firstgas, Vector and Powerco submitted on our approach to setting opex allowances. We also heard from Fonterra and MGUG suggesting that we should further scrutinise the GPBs' AMPs in setting opex allowances.

C17 In its Issues paper submission, Firstgas noted that:[93]

> Our opex forecasts have been prepared using the base step trend (BST) approach, this is the same approach the Commission has used previously to set DPP allowances. Our forecasting approach involves using historical data as a reference point (base year) and adjusting, either in the form of a step, such as increase in maintenance spend due to more equipment to maintain or a trend based on change in network size or connections numbers.

C18 In its cross-submission to the Issues paper, Firstgas again highlighted that there needs to be "flexibility in setting expenditure allowances" and that it "support[s] the view that the Commission should carefully review GPB's AMPs"[94]

C19 In its Issues paper submission, Powerco noted that:[95]

> The Commission is proposing to largely retain its DPP3 forecasting approach, with some tweaks to account for the changes where the future is likely to differ from historical patterns by taking into account step changes and cost inflators. We generally support the overall direction the Commission is heading to forecasting opex, but we do wonder if GDBs AMPs are the most accurate estimate of opex requirements over the

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[92] Firstgas "Submission on the Gas DPP4 Open Letter" (13 March 2025), p.4; Vector "Submission on Gas DPP4 Open Letter" (13 March 2025), p.2 and para. 32-34; and Powerco "Submission on Gas DPP4 Open Letter" (13 March 2025), p.9.

[93] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 10.

[94] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p.19.

[95] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 13.

> DPP4 period. As we have previously highlighted the base-step-trend (BST) approach is less suitable for unstable operating environment, however with targeted scrutiny around the base year (as this is fundamental to ensuring opex allowances are sufficient), and considerations of step changes, the risks of using BST approach are somewhat mitigated. Given the uncertainty and general difficulties highlighted above with forecasting, there is no perfect approach.
>
> The Commission's changes as part of the electricity DPP4 reset to account for changes and uncertainty were really successful, and we encourage the Commission to bring those across to gas.

C20 In its Issues paper submission, Vector submitted that:[96]

> Ensuring the regulatory framework delivers an efficient level of opex should be a key consideration for the reset.
>
> We consider the best course of action would be basing opex forecasts on GPB AMPs (with appropriate scrutiny).
>
> The base, step and trend approach will not deliver a sufficient level of opex for DPP4 without some adjustments and, most critically, unless appropriate step changes are granted.

C21 In its Issues paper cross-submission, Vector reiterated its position that we should assess GPBs' AMPs and set out the views from other submitters support for further scrutiny of the AMPs.[97]

C22 Frontier Economics, on behalf of Vector, submitted that:[98]

> In principle, with adequate flexibility in its application, a BST approach may continue to provide an appropriate opex allowance. However, the emphasis on the step change component of this approach becomes critical.
>
> The Commission flagged applying scrutiny to GPB forecasts in AMPs as an alternative to, or in conjunction with, the BST approach. AMP forecasts are publicly available, and provided the Commission can effectively scrutinise these, we consider this is also a reasonable and pragmatic approach for DPP4. It would provide the Commission with flexibility to look at the reasonableness of overall forecasts.

C23 We also heard from Fonterra and MGUG supporting review and reliance on AMP forecasts.

[96] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025).
[97] Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 19-20.
[98] Vector "Attachment A: Key issues for Ga DPP4 reset report" (prepared by Frontier Economics) (24 July 2025).

Ability to assess AMPs to set opex allowances

C24 Our view is that the GPBs' AMPs do not of themselves provide sufficient information for us to scrutinise opex forecasts, having not been designed to provide detailed drivers of changes in expenditure. If we were to scrutinise the GPBs' AMPs, we would still need to establish a top-down assessment method that may rely on historical averages for consistency, given a bottom-up re-establishment of reasonable opex values would likely not be consistent with a relatively low-cost regime per s53K of the Commerce Act.

C25 Based on submissions, we understand that Firstgas is using a BST approach to forecast opex.[99] Powerco and Vector have also noted that they consider BST could still be used with appropriate adjustments to the components.[100] Considering this, and limitations in the suggested alternative of relying solely on suppliers' AMPs, we consider that using the BST model is an appropriate approach for assessment of GPBs' opex forecasts.

C26 While we expect to see some reduction in the volumes of gas that will be carried over the pipelines in DPP4, opex tends to be more predictable as it relates to recurring activities. We consider a BST approach with step changes or trend factors applied to account for prudent new activities in a less certain operating environment is appropriate.

Additional scrutiny of GPBs' forecast expenditure

C27 We have undertaken discretionary targeted scrutiny of the GPBs' AMPs and issued RFIs where there are other factors we considered required further discretionary targeted scrutiny. Particular areas of focus for the expenditure incurred in DPP3 and forecast for DPP4 related to innovation allowances for blended gases, treatment of disconnection costs and capex/opex substitution.

C28 In addition to the targeted areas above the BST approach has allowed us to apply scrutiny to items of opex that GPBs are forecasting to increase. This has enabled us to determine whether it is appropriate to approve additional opex beyond a GPB's historical activities.

Our draft decisions for the base year

C29 Our draft decision is to set the base year as disclosure year 2024 for all GPBs for the purposes of BST modelling with adjustments to remove non-recurring amounts.

C30 The choice of an opex base value is important because it sets the starting point for the BST modelling that we use for setting the opex allowances over the DPP4 period.

[99] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.10.
[100] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), Vector "Submission on Gas DPP4 Issues paper" (24 July 2025).

Stakeholder submissions

C31 In our Issues paper, we proposed using a single year base value set as the most recent actual levels of opex available.[101]

C32 Frontier Economics on behalf of Vector noted that:[102]

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

C33 We did not receive any other submissions directly related to how we should establish the base year.

We are using disclosure year 2024 opex for the base year

C34 Since the opex base value sets the starting point for the BST modelling it should represent a prudent and efficient level of opex for each GPB.

C35 In addition to using the most recent disclosure year (**DY2024**) opex, we considered the use of alternative approaches including:

C35.1 a multi-year opex average, which smooths historic over and under spend effects;

C35.2 the lowest level of historic opex between DY2023 and DY2024; and

C35.3 the forecast opex allowance from the final year of DPP3 inflated to the first year of DPP4.

C36 Our view is that using the DY2024 as the base year in the BST model is the most appropriate approach.

C37 We consider that in the current environment where there is expected increase in opex to accommodate a more opex centric asset management approach and significant changes in the operating environment and expectations, it would be preferrable to take an approach that represents more recent expenditure values.

C38 A multi-year average approach smooths any anomalies in an individual year but may be less reflective of operating under a more opex reliant business model and the current operating environment.

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[101] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), paras. B77 and B78.

[102] Vector "Attachment A: Key issues for Ga DPP4 reset report" (prepared by Frontier Economics) (24 July 2025), para. 2.4.2.

C39 We do not propose extending the DPP3 forecast opex allowances with an inflation adjustment. These allowances were determined in 2021 and we consider using more recent information is more likely to represent the context in which GPBs are operating.

C40 As noted in the Issues paper, it is our intention to use 2025 data for the base year for our final decision as audited information for that year will be available. This will be applied unless we are not satisfied that DY2025 opex appropriately reflects an efficient level, once non-recurring amounts have been taken into account.

We have adjusted base year opex for non-recurring amounts

C41 We considered what adjustments would need to be made to the base year for non-recurring amounts. We issued an RFI to the GPBs and we received responses from Firstgas Transmission and Distribution, Powerco and Vector.

C42 Powerco and Firstgas Distribution responded that there were no amounts that could be considered non-recurring in DY2024.[103]

C43 In addition to the adjustments we made for non-recurring amounts identified by the GPBs, we have also made targeted adjustments to individual GDBs for disconnections and blended gas investigations, which we discuss below.

C44 For Firstgas Transmission we adjusted the base year down by non-recurring amount for:

C44.1 compressor fuel gas costs, as this will be recognised as a pass-through cost for DPP4 and needs to be removed from opex base to avoid double-counting;

C44.2 specific repairs to pipelines which are unlikely to recur; and

C44.3 blended gas investigations.

C45 For Powerco we adjusted the base year down by adjusting its actual spend on blended gas investigations, to the level of the DPP3 allowance as it signalled its intention to manage within existing regulatory allowances.[104]

C46 For GasNet we adjusted the base year down by removing the DPP3 allowance related to blended gas investigations, due to a lack of information presented on costs incurred or forecasted.

C47 For Vector we adjusted the base year by removing blended gas investigation spend incurred in 2024 since investigating blended gas in networks have been excluded from its 2025 AMP forecasts.[105]

Adjustments related to disconnection costs

C48 The wider context around disconnection costs has been set out within the main reasons paper within paragraphs 3.96 to 3.98.

[103] Powerco and Firstgas Distribution responses to 'RFI2 – Expenditure' (May 2025).
[104] Powerco response to 'RFI2 – Expenditure' (May 2025).
[105] Vector's response to 'RFI2 – Expenditure' (May 2025).

C49 GPBs record disconnection costs as opex under the category “routine and corrective maintenance opex” and accordingly we have considered whether there are likely to be a significant change in scale such that these need to be accounted for under our BST model.

C50 Recognition of recovery of costs associated with disconnections is inconsistent across regulated parties with Vector netting revenue off against the expense, and Powerco and Firstgas recognising the revenue separately as “Other Regulated income”. The treatment will depend on the nature of the contract between the GPB and the retailer and how this should be recorded according to generally accepted accounting practice (**GAAP**).

C51 Based on information submitted in response to RFI2 for Firstgas distribution and Powerco we do not consider an adjustment is required as the existing practices and expected forecast recovery of costs for the DPP4 regulatory period are not materially different.

C52 Exposure to a potential increase in scale of disconnections can be managed by changes to the level of costs recovered, given that is at the discretion of GPBs. We have not implemented a mechanism to address the risk of under-recovery, given design would be complicated and may take away flexibility which is useful in the transition.

C53 For Vector we adjusted the base year by removing disconnection opex as Vector stated that it intended to move to fully recovering the cost of disconnections from consumers in DPP4.

We have considered the levels of blended gas investigation expenditure within GPBs’ base year opex

C54 In DPP3 we provided some opex for the investigation of gas blends in gas networks, that meet our interpretation of natural gas, for the purposes of the regulated service.[106] We considered this was appropriate because:

C54.1 it provided incentives to GPBs to innovate to extend the economic lives of networks, which would be a benefit to consumers of natural gas; and

C54.2 it may reduce carbon emissions whilst using natural gas and still promote the outcomes of s 52A.[107]

C55 We assessed the GPBs’ 2024 opex for levels of expenditure on blended gas investigations separately as it has implications for both the base year and potential step changes.

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[106] Commerce Commission “Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper” (31 May 2022), p.84.

[107] In line with s 5ZN of the Climate Change Response Act 2002, it is open to us to consider matters relevant to the Emissions Reduction Plan, provided this does not detract for the s 52A purpose of Part 4 of the Commerce Act.

C56 Whilst we reviewed information on GPBs plans for blended gas investigations submitted in response to our RFI we are not satisfied there is a case to provide an additional allowance above our DPP3 amount for Firstgas Transmission, Firstgas Distribution and Powerco.

C57 In the case of Vector and GasNet, the AMPs for both GDBs do not mention specific blended gas investigations planned for DPP4 and accordingly we have not proposed an allowance for blended gas investigation.

C58 Table C3 outlines the allowance to be provided for in the DPP4 period.

Table C3 Opex allowance for blended gas investigation[108]

GPB	DPP3 Opex Allowance (2021 $'000s) per annum[109]	DPP4 Period allowance (2025 $'000) per annum
Firstgas Transmission	200	248
Firstgas Distribution	135	168
GasNet	45	0
Powerco	45	56
Vector	45	0

C59 Submitters on our Open letter noted that we should assess the potential role that innovation by GPBs plays to support the energy transition and future use of gas pipelines (such as developing and testing low carbon gas alternatives). The joint GPB submission also suggested we consider options to address a lack of funding such as an "innovation allowance" as allowed for EDBs.[110]

C60 Powerco submitted in response to the Issues Paper that:[111]

> Firstly, using an INTSA-like mechanism to support additional investment where there is a case for socialising the costs of a solution, but rather than 'innovation' it would have an objective of supporting gas transition initiatives -such as rightsizing investigations, planning for decommissioning, supporting customer switching. The DPP4 could provide this as a 'gas energy transition solutions allowance'."

C61 Vector submitted that:[112]

> In our view, an innovation allowance for GPBs could be designed in line with the innovation funding available in the EDB sector. This would ensure GPBs only received funding if their application to the Commission established the research would support the long term benefit of consumers. An innovation allowance could also cover projects

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[108] Table C3 is derived from DPP3 allowances.
[109] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para. 5.80.
[110] Firstgas, Powerco & Vector "Joint submission on Gas DPP4 Open Letter" (13 March 2025).
[111] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p.16.
[112] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), para. 162.

that may further increase the economic efficiency of gas pipeline companies during a winddown.

C62 We also heard from Fonterra that it is supportive of renewable gases, as they are important to its ongoing future operations.

C63 We recognise that trialling low carbon gas alternatives could be an important measure to extend the useful life of the pipelines. This is why we have continued to provide an allowance to GPBs that have indicated their intention to continue investigations.

C64 The design and introduction of the Innovation and Non-traditional solutions allowance (**INTSA**) mechanism within the EDB DPP4 decision was intended to provide an additional incentive to innovate to non-exempt EDBs who lacked strong enough incentives to innovate.[113]

C65 We do not intend to create a similar innovation allowance for GPBs, because:

C65.1 GPBs have a natural incentive to extend the useful life of their networks in order to continue to operate and remain in business and invest where it is economic to do so;

C65.2 the step change for blended gas investigations provided in DPP3 has allowed GPBs to undertake the trials and investigations, with Firstgas beginning its blended gas pilot;

C65.3 we do not consider providing an additional allowance would be reflective of a prudent and efficient amount or allow GPBs to better meet the long-term benefit of consumers;

C65.4 to design and effectively implement an INTSA type mechanism which is not targeting specific actions but broad outcomes is challenging in a DPP context; and

Our draft decisions on step changes

C66 In our Issues paper we proposed setting a list of factors to guide our judgement of step changes as consulted on and applied in EDB DPP4. These factors include whether the step change is:

C66.1 significant;

C66.2 adequately justified with reasonable evidence in the circumstances;

C66.3 not captured in the other components of the DPP allowances;

C66.4 a driver outside the control of a prudent and efficient supplier; and

[113] The EDB DPP4 paper noted that the INTSA would not be the sole source of funding for innovative or NTS projects that an EDB may wish to undertake; these can still be funded through approved expenditure allowances.

C66.5 widely applicable.

Stakeholder submissions

C67 Firstgas, Vector and Power generally supported the step change assessment factors and pointed towards the approach applied in the recent EDB DPP4 reset.

C68 Powerco submitted that it encourages us to "bring in changes in forecasting opex introduced as part of the [EDB] DPP4 reset ... [including] step change criterion."[114]

C69 Vector, via its expert report by Frontier Economics, submitted that:[115]

> The Commission applied set criteria to assess step changes in both its DPP3 and EDB DPP4 decisions. It considered whether the step change was:
>
> - significant
> - adequately justified with reasonable evidence in the circumstances
> - not captured in the other components of the DPP allowance
> - a driver outside the control of a prudent and efficient supplier; and
> - widely applicable.
>
> In our view, these criteria are appropriate for GDB DPP4. They provide GDBs with sufficient guidance on the Commission's approach, while allowing the Commission reasonable flexibility to make its decisions in the current uncertain operating context. We consider that the Commission should also have regard to Vector's AMP in assessing its step changes.

C70 In its Issues paper submission, Firstgas submitted that:[116]

> The Commission's criteria to inform its judgement on step changes for EDBs were that the step changes were significant, adequately justified with reasonable evidence in the circumstances, not captured in the other components of the DPP allowance, had a driver outside the control of a prudent and efficient supplier; and were widely applicable.
>
> We believe the step change criteria of widely applicable should be reconsidered. Each GPB will have different drivers of step changes and may not be widely applicable. An example of this could be the differences between our two gas businesses. For example, in transmission we expect more geohazard remediation to be opex based solutions which will not be applicable to other GPBs, for distribution, we may have different drivers of our opex steps, such as the need to increase leak detection and repairs in older areas of the network. This may not be widely applicable since our distribution network contains more pre-85 pipeline than another GPB

[114] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 10.
[115] Vector "Attachment A: Key issues for Gas DPP4 reset report" (prepared by Frontier Economics) (24 July 2025), section 2.4.3.
[116] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 10 &11.

C71 In its Issues paper cross-submission, Firstgas reiterated again that it considers the 'widely applicable' factor should not be implemented.

We have applied the factors proposed in assessing opex step-changes

C72 Our draft decision is to implement the approach to step changes set out in the Issues paper.

C73 The approach is consistent with that taken in EDB DPP4, with potential step changes assessed against five factors:

C73.1 **Significance** - New operating expenditure that is not a significant increase to the current allowance is expected to be managed by the GPB. This approach maintains the incentives for GPBs to innovate or find efficiencies to better manage operating costs. In addition, we consider that natural variability within opex costs will mean that small increases in some opex costs are likely to be offset by small decreases in opex costs elsewhere. Requiring an opex step change to be 'significant' better gives effect to a relatively low-cost way of setting price-quality paths.

C73.2 **Adequately justified with reasonable evidence in the circumstances -** Providing evidence to support a level of certainty that the new operating cost will occur within the regulatory period, and the amount for the cost, are important aspects to the assessment of step changes. This approach provides for some discretion on information that GPBs can provide to support requests for step-changes.

C73.3 **Not captured in the other components of the DPP allowance** - this factor prevents perverse outcomes where a GPB may be remunerated twice for a cost and prevents unnecessary costs to consumers.

C73.4 **A driver outside the control of a prudent and efficient supplier –** this factor is not so strict as to only cover events that are completely beyond GPB control, but rather focuses on whether a prudent and efficient GPB would undertake the activity that gives rise to the cost. The reason we do not consider expenditure drivers that are directly under GPB control is because GPBs are able to choose how to spend their allowed revenue and may reprioritise within their regulatory allowance in order to undertake discretionary activities. This criterion aims to give effect to the purposes of Part 4 that suppliers have incentives to improve efficiency and share the benefits with consumers, consistent with s 52A(1)(b) and (c). For clarity, there may be situations where a step change is appropriate where the cost is the choice of the GPB, but there are wider environmental/contextual factors driving the costs for GPBs.

C73.5 **Widely applicable** - to maintain the relatively low-cost nature of the DPP, step changes should be applicable to most GPBs, although there may be some circumstances where a step change that clearly satisfies the other factors could efficiently be assessed.

C74 Our draft decision is to maintain the 'widely applicable' factor to inform our assessment of step changes. While we have heard from submitters that there may be step changes in the gas context that are not widely applicable and there are comparatively fewer GPBs to establish a common set of step changes, we note that the factors are not determinative but rather used to inform our judgement.

C75 We have the discretion to consider whether or not the application of every factor in the assessment of a step change is appropriate on a case-by-case basis.

We approved step changes after seeking information from the GPBs

C76 To identify potential step changes which could apply during the DPP4 regulatory period, we sent an RFI to all GPBs. This approach is aligned with what we indicated in our Issues paper, our approach for the EDB DPP4 reset process and was consistent with the approach requested by GPBs.

C77 We requested each GPB use a template to provide information on proposed step changes – being both increases in costs or decreases from historic levels.

C78 Firstgas, Powerco and Vector responded with their requirements for step changes. GasNet did not respond with any step change requirements.

C79 Table C4 below summaries the step changes that we have approved for each GPB as part of our draft decision.

Table C4 Summary table showing approved step changes by GPB

Step	Firstgas Transmission	Firstgas Distribution	Powerco	Vector
Capex-opex trade-off	✓			✓
Cybersecurity[117]	✓	✓		✓
SaaS[118]	✓			✓

Approved step changes

Include a step-change to reflect increased expectations of capex-opex trade offs

C80 Our Issues paper reflected that while opex solutions may appear more costly in the short term, they can help avoid committing to long-term investments that risk becoming stranded. In this context, such an approach could represent a prudent and efficient business decision.

[117] Firstgas on Cybersecurity response to RF4.
[118] Firstgas Transmission SaaS is OATIS upgrade

C81 We stated that it was important for us to understand how these trade-offs are impacting both opex and capex forecasts in setting expenditure allowances and we are interested in how GPBs are considering these trade-offs in their asset management planning processes.

C82 We are expecting a shift of expenditure from a more capital-heavy replacement and renewal programme towards expenditure on maintaining assets through opex. However, the materiality and timing of this shift over DPP4 is uncertain as it will depend on many factors. We consider the ability to shift expenditure will depend on a number of asset specific considerations including location, type, nature of expenditure required and customers on the network.

Submissions on capex-opex trade offs

C83 Our outline of capex/opex trade off was broadly supported by stakeholders.

C84 The Gas Infrastructure Future Working Group (**GIFWG**) described what the alternative gas transition scenarios mean for future gas network expenditure and revenue requirements and how might these vary over time. It represented that:[119]

> Under those scenarios, gas pipeline businesses are expected to substitute operating expenditure for capital expenditure to ensure that can provide a safe and reliable service during the transition period without over-investing in long-lived assets that are only required for a short period of time.

C85 Vector highlighted the need for expenditure allowances to accommodate evolving asset management strategies, recognising the substitution of capex for opex:

> Vector's forecast capex in the 2025 AMP is substantially lower than the 2024 AMP, while forecast opex has increased. This reflects that, as part of a prudent, risk-based approach to asset management, Vector is reducing capex on asset replacement and replacing it with increased annual opex on maintenance.[120]

C86 Similar representations were provided by Firstgas.[121,122] However, it expressed reservations about the ability to quantify the impact of these trade-offs:

> At this stage, it is particularly challenging to directly align opex initiatives with and measurable reductions in capex as the relationship between the two is complex and evolving and might not be linear. Additionally timing mismatches between when opex costs are incurred and when potential capex savings will materialise further complicates the equation. To address these challenges, we have avoided trends for our limited cases of capex/opex trade-offs projections and have instead adopted an approach that reflects practicalities of these trade-offs.
>
> We are also actively exploring capex/opex trade-offs to enhance flexibility and cost efficiency. Short-term opex solutions, such as increased monitoring and maintenance, enable us to manage network risks without committing to long-life capital investment that may not be fully utilised. While precise modelling of these trade-offs remains

[119] Firstgas, Powerco & Vector "Attachment B: Gas transition analysis paper" (prepared by GIFWG) (16 June 2023), p.3
[120] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p.9
[121] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p11
[122] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p19

challenging due to limited historical evidence and timing differences, our approach reflects practical, risk-based decision-making consistent with the Commission's expectation that expenditure prioritises maintaining the system.

C87 Vector referenced the report it commissioned from Frontier economics, in particular noting that a move to opex may not necessarily reduce costs over the long-term. In particular it states:[123]

> In the current circumstances an economically rational approach is to:
>
> • reduce capex on asset replacements (where these costs are recovered over the life of the asset); and
>
> • increase opex on maintenance (which is recovered during a single year).
>
> Increasing maintenance opex can be more expensive over the long term, however it provides flexibility to adapt to future market conditions and makes economic sense if the network has a shorter remaining life. In other words, choosing opex over capex can be a prudent investment to achieve the lowest sustainable cost of delivering pipeline services in an environment of uncertainty regarding the future life of the assets."

C88 Non-GPB submitters also supported the move to a greater focus on opex based solutions with Fonterra stating:[124]

> Fonterra supports the Commission's shift in emphasis from capital-intensive renewals programmes to lower-cost opex maintenance strategies. By relying on up-to-date AMP forecasts (Rather than an automatic historic average) and allowing capex-to-opex substitution, the Commission's draft approach should ensure renewals projects that are only justified by keeping the RAB high are avoided.

Approach for assessing capex-opex trade-off

C89 The Issues paper noted one way to evaluate the impact of capex-opex trade-offs on opex and capex forecasts would be to develop scale factors. This would seek to quantify the relationship between a proposed increase in opex and the corresponding reduction in capex.

C90 Our view is at this stage that there is sufficient information in ID or AMPs to meaningfully assess capex/opex substitution making it difficult to develop reliable scale factors.

C91 Assessing capex-opex substitution through step changes was supported by Powerco who stated:[125]

> We support relying on step changes to account for this shift, as we agree, there is unlikely to be sufficient data to be able to estimate a scale trend, unless there are similarities between the capex/opex substitutions seen in electricity.

C92 Firstgas also noted the lack of availability of historical data in establishing a trend:[126]

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[123] Vector "Attachment A: Key issues for Gas DPP4 reset report" (prepared by Frontier Economics) (24 July 2025), at 2.4
[124] Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), page 2
[125] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p.12.
[126] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.11.

> Moreover, the concept of developing scale factors to quantify capex reductions against opex increases is theoretically sound but remains practically challenging at this stage. Limited historical data in New Zealand on capex/opex trade-offs constrains the ability to develop robust and evidence-based scale factors. Moreover, significant variability in the timing and cost profiles of opex solutions (such as proactive maintenance) compared to capex alternatives (such as asset replacement) makes it difficult to apply standardised scale factors with confidence.

C93 Accordingly, we have considered the capex-opex trade-off as part of our step-change framework within the BST model and separately considered the extent of capex forecast for ARR and RSE given these expenditure categories represent the areas for most likely for substitution.

C94 We have found it difficult to establish definitive corresponding capex reductions for GPBs requesting step-changes in opex related to capex-opex substitution. Consistent with submissions we understand it can be challenging to directly align opex initiatives with measurable reductions in capex as the relationship between the two is complex and evolving and is not necessarily linear. Additionally timing mismatches between when opex costs are incurred and when potential capex savings will materialise further complicates the equation. However, we do consider there should broadly be a relationship between the two. We have not provided a step change in opex if an offset decline in ARR and RSE capex is not demonstrated.

Assessment outcomes

C95 We consider the proposed step-change for all GPBs was significant, had a driver outside the control of a prudent and efficient supplier and was widely applicable.

C96 We have not provided for all capex-opex trade-off step changes requested as we consider there is a risk for some GPBs that it is included elsewhere in the expenditure allowance (specifically in capex forecasts) and the level of evidence to support was not consistent across GPBs.

C97 We have accepted the step change proposed by Vector. Vector has identified that following the development of a Condition Based Asset Risk Management (**CBARM**) model, it has transitioned from a traditional approach of full asset replacement to a data-driven, condition-based strategy focused on targeted intervention of asset subcomponents, without full replacement. It has also identified increases in routine and corrective maintenance to reduce the need for capex-intensive replacements and new installations.

C98 Vector has introduced significant capex-opex trade-offs for ARR opex, some of which are reflected in a 42% reduction in ARR capex compared to its 2024 AMP update over the DPP4 period. It has provided a clear strategy and has explained and quantified the changes in its 2025 AMP with supporting information provided in its response to our expenditure RFI.

C99 We have declined Powerco's request for a step change due to increased opex activities which are focused on maintaining and renewing the network. Powerco represented that through its use of technology and innovation it can significantly improve understanding of asset condition and implement a more targeted approach to asset replacement and renewal. Powerco represented it had a reduction in routine corrective network maintenance costs, offset by a more proactive asset replacement programme to address leakages and losses - which are being detected at higher and more accurate rates due to new detection methods and modelling.

C100 Whilst recognising a difficulty in establishing direct mapping to value the capex-opex trade-off is challenging we have not identified any offsetting impact within ARR capex of the proposed transition to a more heavily based opex programme. Noting Powerco is forecasting a significant uplift in ARR capex for climate adaption and resilience initiatives. Given the ARR capex will be set at historic levels based on evidence reviewed to date we are not convinced providing for this expenditure is consistent with the "Not captured in the other components of the DPP allowance" factor.

C101 We have approved the step change requested for Firstgas Transmission. Firstgas have identified a range of capex-opex trade-offs including;

C101.1 management of technical change for refurbishing equipment and station coatings program becoming a targeted risk and condition-based response rather than capital refurbishment;

C101.2 shorter period management of geohazards risks to its pipelines; and

C101.3 implementing a programme of inspecting heaters rather than inspections completed as part of capital refurbishment projects.

C102 We note Firstgas Transmission is forecasting a material decline in the level of ARR on its pipeline network for the DPP4 period compared to historic levels.

C103 We have declined the step change requested for Firstgas Distribution, the core component of this work programme was for inspection and repairs related to its pre-85 pipe programme. It is not clear that the work programme is a deviation from existing practices which are being employed, and accordingly will already be recognised within the base allowance. We note that in submissions on DPP3 First Gas supported the use of opex for disclosure year 2021 noting this reflected a maturing approach to risk management including new corrective maintenance processes and leak surveys as part of its risk management of pre-1985 polyethene pipe.[127]

C104 No RFI response was provided from GasNet and accordingly no step-change has been provided. We observe that GasNet are not forecasting a material decline in ARR expenditure.

[127] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), p.134.

Including a step-change for increasing cyber-security costs

C105 GPBs have noted their cyber-security costs are likely to increase to manage the increasing external cyber threat including with the transition to more cloud-based systems.

C106 We have approved a step change for GPBs who requested a step-change and provided sufficient information. This applies for Firstgas Transmission, Firstgas Distribution and Vector.

C107 GPBs have provided evidence to support increasing cyber-security costs, whilst there are levels of current spend captured in the base year, there is evidence to support the proposed increases exceed inflation.

C108 We consider the step change is widely applicable and reasonably outside the control of a prudent and efficient supplier.

C109 Whilst most steps requested have been adequately justified with reasonable evidence in the circumstances. We consider there is a risk that the proposed value of the Firstgas Transmission step change request reflects an inefficient level of current and forecasted spend and have accordingly capped the level of step-change allowed.

Include a step change for the costs of software-as-a-service (**SaaS**)

C110 GPBs have indicated that they are looking to transition their current IT systems increasingly to cloud-based 'Software as a Service' (**SaaS**) systems. This step was requested to recognise the costs associated with licensing or subscription fees, set up/implementation costs, and personnel/FTEs to monitor and administer the new systems.

C111 We consider SaaS costs are likely to be significant with the shift to cloud-based solutions forecast to come at a significant opex cost for GPBs – both initial installation costs and then ongoing subscriptions.

C112 We consider the step change is likely to be widely applicable and has a driver outside the control of a prudent and efficient supplier given our expectation on GPBs to appropriately upgrade systems over time to maintain and increase efficiency of operations.

C113 We have approved the step-change requested by Vector which leveraged off information provided as part of the EDB DPP4 submission given the same base year applied.

C114 We have approved the step-change requested by Firstgas Transmission which relates to its Open Access Transmission Information System. We have declined the wider step change for SaaS costs applied for both Firstgas Transmission and Firstgas Distribution related to wider capability improvements. Whilst a significant number of SaaS system were identified in information provided it lacked specificity to assess the costs and accordingly, we consider it was not adequately justified.

Step changes we did not approve

C115 As part of our review of step change, we did not approve the following step changes. These are tabulated in Table C5 together with our reasons.

Table C5 Analysis of step changes that we have declined for the draft decision

Description of potential step change	Analysis and reason for declining
Costs associated with **asset and network decommissioning** requested by Firstgas Transmission. Activities include developing decommissioning procedures, physical site works to safely isolate equipment and updating documentation.	We do not consider it is appropriate to allow a step-change for decommissioning costs when significant uncertainty exists around legal obligations on GPBs, and the scale and extent of costs likely to be incurred.
Stakeholder engagement plans / consumer engagement, involving more direct customer and community engagement, tools and materials about gas and alternatives, which will also need to be informed by more in-depth research for consumer insights.	We consider informing customer decisions on options has value. We note there is currently a lot of mixed messages (reflected in consumer kōrero that the extent of different views makes making decisions harder for consumers). Although consumer engagement expense in aggregate is significant, engagement is taking place at present and is included in the base year. It is not clear that this expenditure could not be accommodated within existing resources previously focused on growth.
Capability uplift for **improved forecasting and planning methodologies**. In particular, investigations into the design of the network to ensure the network can safely and reliably accommodate blended gases and assess the most likely areas where this should happen.	We consider that existing allowances provide for a GPB to undertake forecasting activities and allowances have previously been provided (and spent) for investigation of blended gases. We consider internal capability and competence is within GPB control and is an issue which should have been considered and addressed over the preceding period.
Legal resource for Urbanisation. To comply with required standards and ensure safe operation in urban areas, pipelines will need additional protection. This will include planning advice, property and easement advice, legal advice and stakeholder engagement	We are not clear that there is significant step change in the underlying driver of the costs between the base year and the DPP4 regulatory period. We consider the expenditure has not been adequately justified as we have not been provided data on the volume of pipeline where this needs to be considered and/or addressed to show this has materially changed from the prior period.

We have not applied an aggregate cap on opex step changes

C116 Unlike the approach applied in EDB DPP4 where we capped the amount of total step change allowed at 5% even if individually the step was accepted, excluding specified amounts for insurance and LV monitoring steps, we have not for GPBs applied an aggregate cap on opex step changes.

C117 For EDBs our rationale was that the level of increase to the allowance EDBs were seeking would reach a point where it would be better suited to the scrutiny and analysis that can be applied under a CPP, in line with s 53K of the Commerce Act.

C118 We are not proposing a similar threshold be applied for GPBs.

C119 We consider in the current environment that GPBs should be actively considering the most prudent operational response to network renewals, particularly how opex solutions may be used to extend asset life. In this instance we do not believe a cap would result in outcomes which are in the best interest of consumers.

C120 We note that step changes are not subject to the opex scale growth trend factor outlined in the following section.

Our draft decisions on trend factors

C121 The following sections set out our decisions on opex scale growth, cost escalation and opex partial factor productivity.

C122 Across these decisions, we have sought forecasts that we generally consider are statistically robust and reliable predictions of the drivers of GPB opex. Many of the decisions are technical in nature and are made in pursuit of our goal of accurate forecasting. This in turn results in opex allowances that balance incentives to find efficiencies under s 52A(1)(a), the sharing of those efficiencies with consumers under s 52A(1)(c), and limits on excessive profits under s 52A(1)(d).

C123 Following our review of factors that could influence the trend within the BST modelling, our draft decision is to apply the same trend factors we have applied in previous resets, with an adjustment to account for a likely non-linear correlation between decreases in ICP and reduction in network size. The absence of robust data sets for a declining market makes estimation of elasticity to declines in ICPs difficult.

C124 Our draft decision is to set the following trend factors for GDBs is to:

C124.1 set a network scale trend factor based on historic relationship of network length to ICP growth by:

C124.1.1 weighting network length and ICP change equally at 50% in the elasticity model; and

C124.1.2 applying a floor of 0% in scaling base opex for forecast of network length from ICP change;

C124.2 set a partial productivity factor of 0%; and

C124.3 escalate opex costs using the all-industries labour cost (60% weighting) and a producers' price (40%) indices.

C125 Our draft decision for the GTB is to set:

C125.1 the same trend factors for the partial productivity factor and cost escalation as the GDBs; and

C125.2 the network scale factor at 0%, consistent with the approach applied under DPP3. The GTB operates a highly integrated and capital-intensive network with limited new connections and different operational characteristics compared to GDBs with its opex influenced more by system-wide integrity and long-distance pipeline maintenance, rather than customer connections or urban network expansion.

Our draft decision on network scale trend factor

C126 Similar to DPP3 we have determined a trend factor for the GDBs opex based on changes in network scale. This is modelled by scaling base opex in real terms for estimates of network length and ICP annual growth in each year of DPP4. The ICP growth and network length estimates are modified by an elasticity factor that models their non-linear relationship with opex.

C127 However, there is a significantly different context for DPP4 than previous periods, where all GDBs are expecting declines in the number of ICPs connected to the network.

C128 This point has been noted in submissions from Frontier (for Vector) stating:[128]

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

C129 Vector submitted:[129]

> Consumer numbers are expected to decline over the DPP4 period. This will result in a lower trend factor resulting in a lower opex allowance in real terms over DPP4 relative to the base year. This is a perverse outcome given an appropriate response to declining volumes and connections is for GPBs to increase opex (e.g. on maintenance rather than asset replacement).
>
> While the decline in opex allowances driven by the "number of consumers" factor could be small and there is likely little or no change in network length these impacts still need due consideration by the Commission when setting opex allowances.

C130 Historically, to forecast how increases in network length affect opex need, we used historical trends of network length and GDBs' ICP growth and the relationship between the two. GDBs do not forecast network length increases in their AMPs, so we estimated this relationship based on historical data.

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[128] Vector "Attachment A: Key issues for Gas DPP4 reset report" (prepared by Frontier Economics) (24 July 2025).

[129] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), para. 114.

C131 We quantify the relationship between opex growth and scale growth using elasticities, which give the percent change in cost for a given percent change in scale. For example, an elasticity of 0.9 means that a 10% increase in network scale is expected to give rise to a 9% increase in opex.

C132 We have used an elasticity modelling methodology set out in a 2013 Castalia report submitted as part of the 2013 Gas DPP decision. [130]

C132.1 We have taken a Composite Scale Variable (**CSV**) regression approach between total opex and a composite scale variable with an equal weighting of ICP count and network line length. In this approach, the elasticity is the slope of a standard least squares regression of ln(opex) vs. ln (CSV) where CSV = (ICP count)$^{0.5}$ x (line length)$^{0.5}$).

C132.2 For the dataset we used the GDBs' ICP forecasts as the forecast source instead of Concept Consulting (DPP3), aligning with the CPRG model.

C133 We have estimated an elasticity for DPP4 of 0.445. In DPP3 the estimated elasticity was 0.481. We determined that the CSV approach remains fit for purpose, as it continues to produce regression results that can be considered robust.

C134 The approach we have used to estimate the elasticity is to split network scale effects equally between ICP growth and network length increases, which is consistent with our approach in DPP3. We consider this remains appropriate for its application in trending opex in DPP4.

C135 Given GDBs are forecasting declining ICPs connected to their networks, particularly over later years within the DPP4 regulatory period, we considered the impact of declining ICPs on network length. We do not have a robust historical data series reflecting declines in ICPs with corresponding impacts on network length. Our view is that unlike new ICPs which may arise from connection of new subdivisions and industrial parties and add to network length, a reduction in ICPs won't necessarily result in a reduction in network length. This is particularly so at the early stages of a transition off gas networks when disconnections may be occurring in an unco-ordinated way.

C136 To address this risk, we are retaining the weightings but implementing a floor when forecasting network length so that it does not decline with reductions in ICPs, i.e. When estimating line length as an input to the model in the instance of declining ICPs we do not forecast a negative impact on network length. Whilst this will not hold in perpetuity, i.e., network length will at some stage reduce with ICP disconnections, we consider that absent of a robust dataset to establish a proxy relationship this assumption is appropriate for DPP4.

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[130] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para. A156

C137 We have not applied a floor of 0% for the impact of declining ICPs. We consider there is likely to be a symmetry of costs between increasing and decreasing ICPs and opex.

C138 Accordingly, forecast declines in ICPs will result in reduced opex allowances.

C139 We acknowledge that the nature of costs may change i.e. greater consideration of opex instead of capex but consider that it is most appropriately applied in step changes. We expect GPBs operating in a declining context would be actively looking for cost savings, similar to what would occur in a competitive market.

Our draft decision on the partial productivity factor

C140 Our draft decision is to maintain the partial productivity factor of 0% used in DPP3.

C141 We have found no evidence to indicate that the productivity of GPBs of natural gas pipeline services improved by more or less than the rest of the economy.[131]

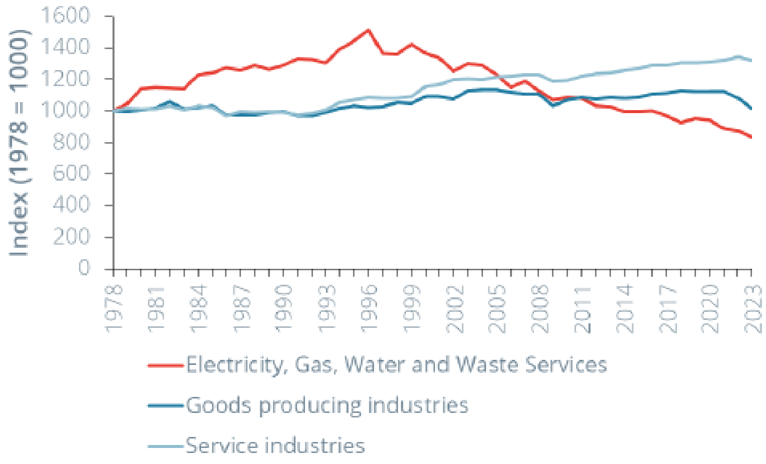
Stakeholder submissions

C142 Vector commissioned and submitted an expert report from Frontier Economics. As part of the report, Frontier considered the partial productivity factor. Frontier provided the following analysis:[132]

> In DPP3, the Commission decided not to apply a productivity adjustment (i.e. 0%). This was based on an earlier finding that there was no evidence to indicate that the productivity of GPBs improved by more or less than the rest of the economy.
>
> We consider the Commission's approach in DPP3 remains appropriate for DPP4. The figure below shows multifactor productivity (MFP) in the utilities industry, which includes gas distribution, has continued to lag behind the goods and service industries. Since the late 1990's, MFP has declined in this sector, indicating there is no compelling reason to change from the Commission's approach in DPP3. Further, with the outlook for falling output and increasing opex, it will be difficult to achieve productivity growth. This doesn't reflect inefficiency for gas pipeline businesses, but rather is a consequence of an uncertain future network.

[131] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022)
[132] Vector "Attachment A: Key issues for Gas DPP4 reset report" (prepared by Frontier Economics) (24 July 2025), Section 2.4.5

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



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

C143 Our view is that with the prospect of lower gas volumes and a shift towards a more opex reliant work programme for the GPBs, it is difficult to predict and draw conclusions on the productivity of the gas sector and any forward-looking estimates of productivity. As the businesses shift to a more opex reliant work programme, it is likely that outputs would remain constant or decrease with an increase in costs from increased opex.

C144 We have also considered Frontier's submission and consider that this is consistent with our own analysis:

C144.1 We took a high-level approach to assessing productivity by taking the Stats NZ produced multi-factor productivity index and comparing the compounded annual growth rate (**CAGR**) of the electricity, gas, water, and waste (**EGWW**) sector from 2018-2021 (when we set DPP3) and 2021-2024. We used this as a proxy to estimate productivity in the gas sector given it contributes to this index; and

C144.2 Based on our calculation, the compound annual growth rate for EGWW has not changed since we set Gas DPP3. Our calculated CAGR is -1.7% for both time periods. Compared to the CAGR to all industries, EGWW still seems to be deteriorating faster compared to the all industries CAGR (with a CAGR over 2021-2024 of -1.2%).

Our draft decision on opex cost escalation factors

C145 Our draft decision is to inflate the GPB opex allowances for input price changes using the weighted average forecast change in:

C145.1 the 'all industries' Labour Cost Index (**LCI**) (at 60% weighting); and

C145.2 the 'all industries' Producer Price Index (**PPI**) (at 40% weighting); and

C146 We have not allowed an additional adjustment to reflect potentially higher costs in the gas sector compared to the sectors represented in the 'all industries' index forecasts.

C147 Changes in input prices affect the annual cost of providing a given level of service and are largely beyond the GPB's control.

C148 Given we provide allowances in nominal dollars, the real base opex and scaled opex trend, over DPP4, is required to be inflated to nominal opex using forecast changes in input prices over the DPP4 period.

Stakeholder submissions

C149 Powerco and Vector submitted that a cost escalation adjustment is required to reflect historical inflation across all utilities and is likely to continue during DPP4.

C150 Powerco submitted that:[133]

> we agree a cost escalation adjustment is required to reflect that the historical higher inflation in the gas sector is likely to continue. As highlighted in the electricity DPP4 reset, reasons for adjustments to both opex and capex inflators apply here to reflect higher historical inflation across all utilities (electricity, gas, water and waste-water sector). The simplest way to account for this, would be to apply the same methodology and adjustments where appropriate, (recognising that capex inflators are different for EDBs and GDBs capex) that were used for the electricity DPP4 reset.
>
> *[footnotes omitted]*

C151 Vector submitted that: [134]

> Opex and capex inflators require an uplift similar to the Electricity DPP4 reset. This could be done on the same basis as electricity if industry specific inflation data is unavailable. However, this approach would still miss categories like traffic management which has increased significantly in Auckland.

LCI/PPI Weighting

C152 We did not receive any submissions directly on whether it was appropriate to continue to apply the LCI/PPI indices which we applied in DPP3 or their weighting, noting Powerco's broader support on our approach to cost escalation noted in its submission above.

C153 Our draft decision is to retain the Gas DPP3 (and EDB DPP4) LCI/PPI weighting of 60%/40% and use the New Zealand Institute of Economic Research forecasts as we did in Gas DPP3. Whilst the current context is dynamic it is not clear there is a significant shift in the mix between labour costs and non-labour costs.

We have not provided an additional adjustment to LCI/PPI

C154 Based on the submissions received, we have undertaken an updated analysis similar to the analysis in EDB DPP4 to assess whether to apply a cost escalation adjustment in addition to the 60%/40% LCI/PPI weighting.

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133 Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 13.
134 Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), para. 124.

C155 In EDB DPP4, we applied an additional 0.3% per annum adjustment to reflect historical higher inflation in electricity, gas, water, and waste sector which we considered would be likely to persist in the medium-term.

C156 While we recognised that there may be higher inflation in EGWW for the EDB DPP4 reset, it is uncertain as to whether the GPBs have the same inflationary pressures as the EDBs.

C157 Our draft decision is not to include a cost escalation adjustment.

Attachment D Addressing the risk of economic network stranding

Purpose of this attachment

D1 This attachment explains the rationale for our draft decision to mitigate the risk of network stranding in DPP4, by completing the transition to shorter regulatory asset we started in DPP3 to better reflect economic asset lives.

D2 It describes:

D2.1 the regulatory problem of network stranding and the adverse consequences for consumers over the long-term if stranding risk is not addressed;

D2.2 how we addressed network stranding risk in DPP3;

D2.3 our view of developments in relevant contextual factors affecting network stranding risk and economic asset lives for GPBs since the DPP3 reset;

D2.4 how our draft decision to shorten asset lives in DPP4 to mitigate economic network stranding risk was informed by our long-term stranding model; and

D2.5 how our draft decision satisfies the criteria in the GDB and GTB IMs for adjusting average regulatory asset lives at DPP4, by:

D2.5.1 better reflecting economic asset lives; and

D2.5.2 better promoting the long-term benefit of consumers of gas pipeline services.

Structure of this attachment

D3 In Table D1 we describe the structure of this attachment.

Table D1 Structure of this Attachment

Title	Description of content
Introduction	Sets out the purpose of this Attachment, how it is structured and what it covers
Overview of our DPP4 draft decision	Summarises our draft decision for DPP4 together with key supporting information and our reasons
Background	Provides relevant background, including a summary of our DPP3 network stranding mitigation decision
Our approach to assessing risk and mitigation for DPP4	Describes how we determine, via our scenario modelling, whether to adjust regulatory asset lives at DPP4 to mitigate network stranding risk

What developments have occurred since the DPP3 reset?	Outlines the key contextual developments we have observed since the DPP3 reset affecting network stranding risk and economic asset lives for DPP4
What we heard from stakeholders	Summarises the main views on network stranding risk and modelling scenarios received from submitters
Our assessment taking into account stakeholder views	Discusses how information (including submissions from stakeholders) has informed our draft decision
Updates to technical parameters of stranding model	Explains updates to the long-term network stranding scenario model to make it fit-for-purpose for DPP4

Overview of our DPP4 draft decision

Network stranding risk at DPP4 threatens the long-term benefit of consumers

D4 As we outline in Chapter 2, a high level of uncertainty surrounds the pace at which future demand for pipeline services may decline as New Zealand transitions to a low-emissions economy. This raises a risk of GPBs' large upfront investments in long-lived pipeline assets becoming economically stranded at some point in the future.[135]

D5 If network stranding risk is not adequately addressed, it can undermine the incentives for GPBs to continue investing efficiently in infrastructure needed to meet the needs of current and future consumers. This threatens the long-term benefit of consumers and therefore the promotion of the Part 4 purpose in s 52A of the Act.

D6 For DPP3, we shortened average regulatory asset lives under the GDB and GTB IMs for each GPB to better reflect economic asset lives in DPP3 and better promote the Part 4 purpose. The risk of economic network stranding was mitigated by bringing forward the recovery of a portion of GPBs' RABs (via depreciation) to DPP3, providing GPBs with a more realistic expectation of cost recovery than using estimated physical asset lives.

D7 Our DPP3 decision assumed that the full transition to ensure that regulatory asset lives better reflect economic asset lives would occur over two regulatory periods. We implemented approximately 50% of the total required transition in DPP3.[136] We said we expected to complete the transition to shorter asset lives in DPP4, subject to a fresh assessment of stranding risk and economic asset lives at the time.[137]

[135] Gas pipeline networks can become fully or partially economically stranded if a GPB does not expect to recoup its network investment and operating costs (including depreciation and a normal rate of return) through revenues over time, thus not achieving expectations of ex ante Financial Capital Maintenance (FCM) under our building blocks framework applied when setting a DPP.
[136] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras 6.28.3; D49. The estimate of 50% was based on our assessment of the overall risk to mitigate at that time.
[137] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras X19; 6.30. We note that under the GDB and GTB IMs for ID

Our draft decision is to complete the transition to shorter asset lives for GPBs in DPP4

D8 Our draft decision is to specify asset life adjustment factors for each GPB in DPP4 to shorten average regulatory asset lives and complete the transition to the regulatory asset lives for GPBs that we started in DPP3.

D9 We are satisfied that applying asset adjustment factors in DPP4 to complete the transition to shorter regulatory asset lives, meets the relevant criteria in the GDB and GTB IMs as it:[138]

D9.1 will better reflect economic asset lives; and

D9.2 will better promote the purpose of Part 4 for the long-term benefit of consumers.

D10 Adjusting regulatory asset lives alters depreciation allowances in DPP4 and produces building blocks allowable revenue for DPP4 consistent with a credible long-term revenue trajectory. This allows GPBs a reasonable expectation of achieving a normal return over the lifetimes that their networks are assumed to be used.

D11 Applying asset adjustment factors therefore better reflects economic asset lives.

D12 With respect to the long-term benefit of consumers:

D12.1 We consider—consistent with analysis in our 2023 IM review—that adjusting asset lives to mitigate uncertainty over future cost recovery under our building block framework remains appropriate at this time to support incentives for GPBs to continue investing in their networks (including in replacement, upgraded, and new assets) – s 52(1)(a).[139]

D12.2 Asset life adjustments that better reflect economic asset lives reduce the risk of future consumer price shocks, giving consumers the confidence to continue using gas if they wish, and mitigates the risk of early network closures. GPBs

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regulation shortened lives from DPP3 automatically carry over to DPP4 via the ID RAB to maintain higher levels of depreciation from DPP3. However, a further shortening of asset lives in DPP4 is required to implement further mitigation in that period and reflect economic asset lives (eg, to complete the expected transition).

[138] GDB and GTB IMs, cl 4.2.2(4).

[139] The GDB and GTB IMs and our approach to setting prices under the BBM for DPP4 are underpinned by the ex-ante FCM principle. In the 2023 Part 4 IM review we considered whether there were any viable alternatives to applying the ex-ante FCM principle at this time. We were not provided with any alternative IMs that would promote the s 52A(1) outcomes better than continuing to have IMs that are underpinned by the ex-ante FCM principle. We also concluded that removing inflation indexation of the RAB, altering the straight-line method for calculating depreciation, or providing an ex ante compensation mechanism for DPPs was not appropriate. See: Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), paras 3.276-3.447.

will therefore have incentives to provide services to consumers while demand exists, at a quality that reflects consumer demands – s 52A(1)(b).[140]

D12.3 Increasing allowable revenues via shortening regulatory asset lives is NPV-neutral with respect to GPBs' cost of capital over the lifetime of networks, so GPBs will remain limited in their ability to extract excessive profits – s 52A(1)(d).[141]

D13 Applying asset adjustment factors in DPP4 therefore better promotes the Part 4 purpose.

Our decision was based on the most up-to-date information

D14 We were guided in our assessment by our long-term stranding model from DPP3.[142] We updated cost inputs and other variables to reflect the most recent financial data. We also considered whether the two long-term network wind-down scenarios contained in the model (an assumed industry wind-down by 2050 and 2060 respectively), and their corresponding weightings in our assessment (33% and 67%), remained appropriate in light of circumstances at DPP4.[143]

D15 A key conclusion we reached after considering a range of information, including views from stakeholders, is that despite risk from various sources having changed to some extent since the DPP3 reset, the two industry wind-down scenarios from DPP3 remain central in our estimation of economic network stranding risk at DPP4.

D15.1 Domestic gas reserves are declining more quickly than expected. This factor weighs somewhat more strongly in our consideration. However, we consider that retaining the assumed 2050 wind-down scenario from DPP3 is sufficient to recognise the risks associated with accelerating declines in usage and an early industry wind-down due to constrained supply-side conditions.

D15.2 Government policy toward gas exploration has changed, and future imports of gas are possible, offsetting to some degree the faster decline in current domestic gas reserves. On balance, these developments have not changed our overall assessment of network stranding risk at DPP4, particularly as policy changes can take some time to translate to physical changes in gas supplies.

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[140] Having more efficient pricing signals should discourage inefficient new connections, and may be of importance during DPP4 as existing gas consumers will likely be making decisions on how they use gas and invest in gas-dependent infrastructure, including decisions on whether to repair or replace aging gas appliances or transition to other energy sources such as electricity or bottled gas for heating/cooking.
[141] GPBs will record higher depreciation in ID for each year of DPP4, and this will reduce the RAB values available at DPP5 to set prices.
[142] For a full description of the stranding model, including the assumptions underpinning it, see Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), Attachment C.
[143] Each scenario modelled a long-term declining profile of pipeline revenues expected to be sufficient to allow GPBs to recoup total pipeline costs (including a normal return) over time. The profile was assumed to fit within the collective willingness and capacity for consumers of gas pipeline services to pay, at all points in the scenario.

D15.3 The prospect of some material level of reticulated natural gas use continuing beyond the 2050 net zero carbon emissions target was a primary reason for introducing the 2060 wind-down scenario, and weighting it more heavily than the 2050 wind-down scenario, in our DPP3 final decisions.[144] We consider the possibility of longer-term future use of gas pipelines remains adequately recognised by retaining the 2060 wind-down scenario in our model for DPP4.

D16 The key features of the two long-term scenarios adopted in our long-term network stranding model for the DPP4 draft decisions are summarised in Table D2. The scenario parameters are similar to those in our DPP3 decision. We consider them to be plausible and reasonable ones for determining asset life adjustment factors at DPP4.

Table D2 DPP4 network stranding modelling scenarios – draft decision

Network wind-down year	MAR ramp-up	MAR in last year ÷ 2023 MAR	MAR ramp-down shape	Opex in last year ÷ 2027 opex	Capex in last year ÷ DPP3 average capex	Weight allocated to scenario result
2050	None	20%	Linear	30%	20%	33%
2060	None	20%	Concave	30%	20%	67%

D17 The outputs of our stranding model for DPP4 (ie, asset life adjustment factors) are shown in Table D3, after updates to the model for building blocks input costs and variables were made to align with the most up-to-date financial information.

Table D3 DPP4 network stranding mitigation – draft decision ($m, nominal BBAR, all depreciable assets)

GPB	Asset life adjustment factor (2 dp)	Forecast DPP4 depreciation allowance before adjustment	Forecast DPP4 depreciation allowance after adjustment	Additional forecast depreciation in DPP4
Firstgas Transmission	0.71	303.8	425.9	122.2
Firstgas Distribution	0.68	63.1	92.8	29.7
GasNet	0.62	7.1	11.4	4.3
Powerco	0.69	122.7	177.4	54.7
Vector	0.77	126.8	164.0	37.2
Sector total		**623.5**	**871.5**	**248.1**

[144] 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 value. See para D30 below.

D18 When asset adjustment factors are applied to shorten average regulatory asset lives in our DPP4 financial model, the period over which GPBs' investment in assets is to be recovered is shortened, which increases the allowance for depreciation in DPP4 (Table D3). This effectively brings forward the recovery of a portion of GPBs' RABs to DPP4, lowering the exposure of GPBs to economic network stranding risk.[145]

D19 The adjustment factors for DPP4 in Table D3 are substantially less than 1 for each GPB and have a material effect on depreciation allowances. This indicates that if asset lives were not shortened in DPP4 (or in future periods) then material shortfalls could exist with respect to costs recovered from consumers over the lifetime that networks are assumed by our modelled scenarios to be used.

D20 We consider that applying the asset life adjustment factors shown in Table D3 in DPP4 to achieve the expected transition to shorter regulatory asset lives that we started in DPP3 is the best option for consumers in the current circumstances.

D20.1 Each GPB will have a reasonable expectation of achieving cost recovery in DPP4 and a normal return over the period that their networks are assumed by our modelled scenarios to be used to convey natural gas.

D20.2 Deferring the alignment of regulatory asset lives in DPP4 with economic asset lives to a future reset would likely increase the risk of economic network stranding and undermine GPBs' incentives to invest in DPP4.

D20.3 Given that demand for reticulated gas seems now to have plateaued ahead of DPP4 (or is declining for some GPBs),[146] addressing the risk while the customer base is likely at its broadest:

D20.3.1 likely minimises total required pipeline charges over time; and

D20.3.2 provides headroom to manage possible future price shocks for consumers from the energy transition.[147]

[145] Shortening asset lives, in conjunction with the straight-line depreciation method applied under our BBM framework by the GDB and GTB IMs, increases depreciation allowances for both existing and forecast new assets in each year of the DPP. The depreciation amounts shown in Table D3 are forecasts for both existing assets and additional assets. The forecast depreciation specified in the DPP determinations for the GTB and GDBs for ID compliance purposes is specified in respect of existing assets only (per IM requirements).

[146] This is a change in expectations since the DPP3 reset when GPBs forecast that demand was likely to remain relatively stable (or grow) throughout DPP3: Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para E53.

[147] With expectations of long-term declining demand, prices per unit of gas conveyed will rise if BBM costs remain steady (all else equal). Shortening average asset lives to bring forward cost recoveries to a time when more gas is being conveyed reduces the risk of price shocks and the extent to which future prices might be disproportionately higher. This mitigates the risk that some future consumers may not be willing to pay required pipeline charges in the future. It may also be more equitable for consumers over time. Future resets will provide further opportunities to consider either shortening or lengthening regulatory asset lives (as required) to adjust future levels of stranding mitigation and reflect the associated economic asset lives based on information available at the time.

D20.4 Acting now preserves options which may be valuable to consumers.[148]

D21 We considered information provided by submitters about the possible adverse effects of increases in pipeline charges during DPP3 on demand, and recent cost pressures being experienced by consumers due to increases in the wholesale price of natural gas, inflation and other economy-wide factors. We concluded that the extent of asset life shortening in DPP4 is not required to be limited to manage short-term price impacts for consumers of gas pipeline services.

D22 Our draft decision is that the asset life adjustment factors returned by our network stranding model (Table D3) should be applied, without the need for any adjustment to those factors to manage shorter-term price impacts for consumers, for GPBs in DPP4.

D23 The GDB and GTB IMs allow GPBs the flexibility to adjust asset lives for specific assets (or asset types) in their ID RABs to align with a GPB's own assessment of stranding risk and asset lives for its network – as long as the overall effect of the GPB's adjustment across all assets equates to the implied average remaining asset life and depreciation forecasts produced by our modelling.[149]

Draft mitigation measures will be updated for final decisions

D24 Subject to consultation outcomes, we will apply the same analytical and modelling approach in our final decision. Final asset life adjustment factors for DPP4 are likely to change however, as our modelling outputs depend on variables that will be updated at the time of the final decision (eg, opex base year costs and expenditure allowances, DPP4 WACC). We will also consider any changes we identify in the sector outlook affecting network stranding risk, and if measures are needed to manage any price impacts for gas consumers resulting from changes to asset adjustment factors.

Background

Network stranding risk threatens incentives to invest

D25 As discussed in Chapter 2, expectations of a long-term decline in the demand for natural gas and other uncertainties increase the risk of GPBs' current and future investments in gas pipeline networks becoming economically stranded.

D25.1 If consumers, collectively, are not willing or able to pay the required pipeline charges over time (calculated to recover GPBs' capital and operating costs), or if pipeline operations were to cease prior to full recovery of the RAB, then GPBs will not expect to recover the economic costs of their total investments, ie, will expect to make less than normal profits over the lifetime of their investments.[150]

[148] See Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para C63.5.
[149] GDB and GTB IMs, clause 2.2.8(5).
[150] The risk is asymmetric, as GPBs profits are constrained on the upside (Part 4 regulation operates to cap revenue or average prices of GPBs) but not the downside.

D25.2 If the risk is material, and not compensated for in our building block model (**BBM**) revenue-setting framework, then it will likely threaten incentives for GPBs to invest and innovate to meet the needs of current and future consumers to the extent that pipelines remain used to satisfy demand for gas.

D26 To mitigate economic stranding risk when setting a DPP, the GDB and GTB IMs permit us to shorten (or lengthen) a GPB's average regulatory asset lives by applying an 'adjustment factor' which alters the timeframe over which assets generate the BBM depreciation component of DPP allowed revenues.[151]

D26.1 This alters the pace that a GPB's investment costs (represented by the GPB's RAB) are recovered. Shortening average regulatory asset lives, for example, accelerates the recovery of the RAB in the current DPP period, effectively removing that accelerated portion of RAB from risk of economic stranding in future periods.

D26.2 Changes to asset lives affect BBM depreciation and are NPV-neutral with respect to GPBs' cost of capital; the present value (calculated using that cost of capital) of total costs to be recovered from consumers does not increase.

D27 We can decide to apply an adjustment factor for a GPB as part of a DPP reset when determining regulatory asset lives used to calculate depreciation if we are satisfied it would better reflect economic asset lives for that GPB and if doing so better promotes the Part 4 purpose contained in s 52A of the Act.[152]

D27.1 In the context of DPP4 and the long-term stranding model we are applying, we consider that regulatory asset lives will better reflect economic asset lives if they support sufficient allowable revenues in DPP4 to align with a long-term trajectory of revenues that is reasonably expected to achieve a normal return for a GPB during the time that the networks are assumed to be in use under our modelled scenarios.

We mitigated some impact of declining demand in DPP3

D28 At the DPP3 reset, we shortened average asset lives by applying an adjustment factor calculated with respect to our assessment of the network stranding mitigation required for each GPB.[153] With respect to the criteria contained in the GDB and GTB IMs, we considered:

D28.1 Shortening regulatory asset lives at DPP3 better reflected economic asset lives, and we observed that the shortened lives were likely to better match the shorter period over which gas might be expected to be demanded and/or the

[151] Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths – Reasons Paper" (30 May 2022), Chapter 3.
[152] GDB and GTB IMs, clause 4.2.2(4). Different adjustment factors can be specified for different GPBs.
[153] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022) – para 4.26 –4.31; Chapter 6.

network might convey gas, rather than the period implied by estimated physical lives of network assets;[154] and

D28.2 The risk of future stranding was material and was not compensated for elsewhere in our BBM framework. If not addressed, the risk could threaten incentives for GPBs to continue investing in their networks to satisfy current and future consumer demand. Applying an adjustment factor to mitigate the risk therefore promoted the long-term benefit of consumers.

Our DPP3 decision was informed by a long-term stranding model

D29 To estimate the extent of the shortening required we developed a long-term stranding model which adopted some assumptions about long-term BBM costs and revenue recovery profiles over time under two plausible industry scenarios (ie, a winding down and eventual closure of gas networks in 2050 and 2060 respectively).

D29.1 The model calculated adjustment factors for each GPB that, when applied to average remaining regulatory asset lives at the commencement of the 4-year DPP3 period, altered depreciation in DPP3 to align each GPB with the revenues required for the initial (4-year) portion of a long-term trajectory of revenues.

D29.2 The long-term revenue trajectory was shaped to allow an expectation of full recovery of long-term projected building block costs (including the unrecovered value of past depreciable network investments, assumed future network capex and opex, tax and other BBM cost components) via pipeline charges by the wind-down dates, and to generate relatively stable prices in real terms per unit of gas conveyed;[155] and

D29.3 We assumed that the collective willingness and capacity to pay of consumers of gas pipeline services would stay above the profile of allowed revenues at all points in time, providing GPBs with an expectation of FCM.

D30 We considered that the wind-down timeframe, and associated long-term revenue trajectory, adopted by each of the two scenarios in the stranding model to be central in terms of the distribution of risk of network stranding at DPP3.[156] That is, the scenarios, weighted together, represented a plausible central estimate of the total period over which networks might be operated, with their associated revenue trajectories providing a reasonable expectation of achieving normal returns over successive resets.

D30.1 We weighted the 2060 scenario more heavily (67%) than the 2050 scenario (33%) to recognise the possibility of gas use continuing past New Zealand's 2050 CCRA target for net carbon zero emissions,[157] but also to acknowledge

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[154] These estimates were contained in "Schedule A – Standard Physical Asset Lives" in the GDB and GTB IMs, and ranged from 10 years to 80 years across different asset classes.
[155] Our assumption was that allowable revenues at the relevant wind-down date would decline to 20% of 2023 allowable revenues, in nominal terms.
[156] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para D45.
[157] Climate Change Response Act 2002, s 5Q.

that a longer wind-down scenario could be seen as a possible proxy for an earlier wind-down scenario with some residual value.[158]

D31 We included a transitional 6-year 'ramp-up' period at the start of the model's long-term revenue trajectories to strike a balance in the long-term interests of consumers between the benefits of moving relatively quickly to address network stranding risk, against the impact of short-term price increases.

D31.1 Conceptually, the ramp-up period deferred some part of the asset life shortening required in DPP3 to transition GPBs onto a new long-term revenue trajectory, for consideration in a future price reset when further adjustments to asset lives (and therefore the pace of depreciation) could be made. The ramp-up assumption resulted in four of the six years of increases in revenue for the six-year ramp-up period occurring in DPP3. As the increases are cumulative, approximately 50% of the total additional revenues occur in DPP3. This assumption implied that the remaining 50% occurs in the two years following (ie, in DPP4).[159]

D31.2 We also applied smoothing mechanisms to DPP3 for most GPBs to ensure constant real average annual price increases occurred, and a 10% cap (in real terms) for any annual revenue increases. The cap applied to limit Firstgas Distribution's increase in allowed revenues—and therefore the extent of its regulatory asset life adjustment and network stranding mitigation—in DPP3.[160]

D32 We emphasise that the objective of our stranding modelling was not to determine the likely future end-state of the gas industry, but to assess the extent of regulatory action at DPP3 that best promoted the long-term benefit of consumers of gas pipeline services under a range of plausible future outcomes.

Our approach to assessing risk and mitigation for DPP4

Assessing extent of asset life shortening for the DPP4 reset

D33 As mentioned above, our DPP3 decision assumed that the transition to shorter regulatory asset lives to better reflect economic asset lives and mitigate network stranding risk would occur over two regulatory periods (ie, DPP3 and DPP4).

[158] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para D46. The residual value may arise from the repurposing of existing pipelines to convey gases that are not natural gas (eg, full hydrogen conversion). Any such residual value should reduce the amount of capital (and depreciation) required to be recovered from consumers of regulated gas pipeline services over time.
[159] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022) , para D49.
[160] We also rounded the impact of the blended adjustment factor on the starting price adjustment or DPP4 X-factor to the nearest 0.5 percent: Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022) , para D51.

D34 In our DPP4 Issues Paper, we signalled that we intended to assess stranding risk at DPP4 by adopting the DPP3 stranding model and considering:

D34.1 if any changes to the long-term modelled wind-down scenarios were needed to reflect industry developments since the DPP3 reset affecting stranding risk; and

D34.2 updates required to building block cost variables and other technical parameters in our stranding model to ensure they remain fit for purpose at DPP4.[161]

D35 Our expectation was that re-applying our DPP3 stranding model to DPP4 would produce a new set of adjustment factors to apply at DPP4, further adjusting regulatory asset lives and completing the transition to shorter asset lives (and higher revenue levels) that we had started in DPP3.

D35.1 As we describe above, the model calculates adjustment factors necessary to generate sufficient regulatory depreciation in DPP4 to align DPP4 allowable revenues with the 5-year (ie, DPP4) portion of the long-term modelled trajectory of revenues for each GPB. This contributes to a reasonable expectation of a normal return being achieved by GPBs over the timeframe that networks are assumed to operate under the modelled scenarios.

D35.2 Any changes made to the DPP3 modelling which we apply to DPP4 would alter the adjustment factors for each GPB to be implemented at DPP4 (relative to those we had expected to apply to DPP4 at the DPP3 reset).

D36 The shortening of regulatory asset lives in DPP4 completes the change to regulatory asset lives that better reflect economic asset lives that we started in DPP3.

We reviewed the appropriateness of our modelled scenarios

D37 In our Issues Paper we stated that the two scenarios employed in the DPP3 network stranding model appeared to be reasonable starting points for the DPP4 reset, as they:

D37.1 align with expectations that a progressive wind-down of natural gas, or any eventual cessation of gas pipeline services, will occur at a future date beyond DPP4 (ie, future network closure may occur, but does not seem imminent);

D37.2 recognise that the use of piped natural gas could conceivably end either by New Zealand's current legislative climate policy target for net accounting carbon zero of greenhouse gases (other than biogenic methane) of 2050,[162] or extend beyond 2050, for example, for some hard-to-abate industrial uses; and

D37.3 represent a range of assumptions, for instance, the 2060 wind down scenario assumes a moderately concave decline in consumer willingness to pay,

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[161] Commerce Commission "Gas DPP4 - Issues paper" (26 June 2025), paras 4.30 – 4.36; 4.46 – 4.48.
[162] Climate Change Response Act 2002, s 5Q.

reflecting a possible greater ability of some future consumers to absorb price increases than under the straight-line profile adopted for the 2050 scenario.[163]

D38 In reviewing the appropriateness of these modelled scenarios at DPP4 we have sought to establish an overview of the main developments in factors affecting stranding risk that have occurred since the DPP3 reset, having regard to information contained in:

D38.1 GIC's Gas Supply and Demand Study 2024;[164]

D38.2 GPBs' 2025 Asset Management Plans;[165]

D38.3 Concept Consulting's Gas DPP4 draft demand forecasts report;[166]

D38.4 RFI asset life data supplied by GPBs;[167]

D38.5 New Zealand's Second Emissions Reduction Plan (2026-30);[168] and

D38.6 Government policy announcements and publicly available media reports.

D39 We have then considered stakeholder views, including those on the impact of relevant industry developments and possible need for mitigation measures in DPP4.

D40 As discussed below, our review of the scenarios we modelled for DPP3 included a workshop session with industry stakeholders, covering both general context and technical modelling elements.[169]

What developments have occurred since the DPP3 reset?

D41 Our DPP3 reset final decision—published on 31 May 2022—noted that New Zealand had embarked on a long-term transition to a decarbonised economy with a legislated target for net zero carbon emissions by 2050 (and for each year after that).[170]

D42 In the absence of any definitive information about the likely speed and extent of the expected decline in natural gas (and gas pipeline) usage at DPP3, we concluded that a number of variables could influence industry outcomes and risk of network stranding.

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[163] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 6.21.
[164] Gas Industry Co. (GIC) "Gas Supply and Demand 2024" (2024).
[165] See Chapter 3 of the Gas DPP4 Draft decision reasons paper (27 November 2025).
[166] Concept Consulting "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (prepared for the Commerce Commission, 22 August 2025)
[167] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), Attachment D.
[168] Ministry for the Environment "Our journey towards net zero: New Zealand's second emissions reduction plan 2026-30" (11 December 2024).
[169] Commerce Commission "Gas DPP4 2026 – Scenario modelling workshop" (15 July 2025); Commerce Commission "Gas DPP4 – Scenarios modelling workshop slides" (15 July 2025).
[170] Climate Change Response Act 2002, s 5Q. Natural gas contributes to New Zealand's greenhouse gas emissions so natural gas usage is expected to decline.

D43 These included policy measures introduced by the current or future governments in response to climate change, possible uncertainty over gas supply and potentially rising costs of wholesale gas due to higher costs of production, viability of alternative energy sources for consumers, whether pipelines can be repurposed to carry alternative gases, economic interdependencies with other sectors such as electricity, and consumer preferences.

D44 We outlined the current 'state of play' for these factors at the date of our DPP3 decision (including interdependencies between various factors) and described some of the key expected developments (in energy policy particularly) ahead of DPP4.[171]

Long-term direction of travel

D45 The Climate Change Commission (**CCC**) which monitors progress with the first three emissions budgets published by the Government (covering the period 2022 to 2035) in relation to New Zealand's net zero carbon emissions target concluded in its July 2025 report that greenhouse gas emissions reductions are on track for the first emissions budget, with total net emissions continuing to fall.[172]

D46 The second Emission Reduction Plan (**ERP2**) for the period 2026 to 2030 was released on 11 December 2024 and builds on ERP1.[173] It confirms demand for natural gas is expected to reduce in the long-term (but notes a role for gas in electricity generation out to 2050). It discusses enabling carbon capture, utilisation and storage (**CCUS**) technologies, and policy measures to facilitate the uptake of renewable gases such as biomethane. It also mentions the potential role of hydrogen for future emissions budgets.

D47 ERP2 places less of a focus on the phasing out of natural gas (ie, no long-term target date or transition pathway is signalled) than in ERP1, and more on options for securing the economic use of gas (and renewables) for New Zealand during the energy transition.

D48 The energy policies signalled by the previous Government in ERP1 released in May 2022 (ie, the Gas Transition Plan and Energy Strategy) were not completed.[174]

D49 Since the change in Government in late 2023 there has been an increasing focus on energy security and addressing short- to medium-term supply challenges (see below) affecting gas markets and wholesale prices.

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[171] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022) , Chapter 3.
[172] Climate Change Commission "Monitoring report: Emissions reduction" (July 2025).
[173] Ministry for the Environment "Our journey towards net zero: New Zealand's second emissions reduction plan 2026-30" (11 December 2024). The first Emissions Reduction Plan (ERP1) released on 16 May 2022, prior to the DPP3 reset, set out the government's policies and strategies for meeting the first emissions budget for 2022 to 2025.
[174] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras X31; 3.32-3.33.

D49.1 The ban on new offshore oil and natural gas exploration permits introduced in 2018 was reversed in July 2025.

D49.2 An energy package was announced in October 2025, including invitations to tender for an LNG import facility to be used for energy firming.[175]

D49.3 An announcement in November 2025 that the up to $200 million of Crown co-investment in the development of new gas fields previously announced is to be extended to cover additional drilling in existing gas fields.[176]

D50 The Government's Statement on Biogas announced on 22 October 2025 signalled its support for industry-led investment in a renewable gas market in New Zealand.[177]

D51 ERP3 for the period 2031 to 2035 is due by the end of 2029 (ie, during DPP4), and the government is currently required to set the fourth emissions budget (for the period 2036 to 2040) during 2025. In November 2024, the CCC recommended annual average emissions in the fourth budget be set at levels 56% lower than they were in 2022.[178]

Short-term supply challenges and demand plateau

D52 The GIC's Gas Supply and Demand Study 2024 indicated that New Zealand may face supply shortfalls in the 2030s without sufficient domestic gas discoveries (or imports). The study identified declining production from existing fields and the impact of past policies on new exploration as primary reasons for this.[179]

D53 Domestic gas reserves are now declining more rapidly than expected (including at the time of our DPP3 decision) and forecasts of demand for gas pipeline services have been revised downwards.

D53.1 At the DPP3 reset, stable or moderately growing demand had been projected through DPP3 (2022 to 2026) and into the initial years of DPP4.

D53.2 In 2025 AMPs, GPBs revised 10-year demand projections downwards. While there is some variation in extent of revision among GPBs, all GPBs are now projecting accelerated declines in throughput and net connections (**ICPs**).

D53.3 Concept Consulting's gas pipeline demand projections produced in August 2025 are broadly in line with GDBs' AMPs, although Concept projected greater decline in ICPs over DPP4.[180]

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[175] See Beehive website.
[176] See Beehive website.
[177] See Beehive website.
[178] Climate Change Commission "Advice on Aotearoa New Zealand's fourth emissions budget" (November 2024).
[179] Gas Industry Co. (GIC) "Gas Supply and Demand 2024" (2024). The 2024 winter was a 'dry' one: low hydro lake levels created an acute need for gas for energy firming, and wholesale gas prices peaked to very high levels.
[180] Concept Consulting "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (prepared for the Commerce Commission, 22 August 2025).

D54 While some GDBs continue to advertise reticulated gas as a fuel for the future,[181] and all offer new customer connections provided a gas retailer is willing to offer a customer plan, it seems that overall demand for gas pipeline services has plateaued and a decline will commence earlier than expected at the DPP3 reset.

Changes in consumer preferences

D55 In our DPP3 decision we discussed how changes in consumer sentiment towards gas use over time, and the price competitiveness of alternative energy sources, would likely be factors which prompt a change in consumer energy choices resulting in decreasing demand for natural gas.[182] Key aspects included:

D55.1 Rising awareness of climate change among mass market consumers, and pressures on business gas users to operate in environmentally sustainable ways; and

D55.2 Commercial and technological progress in other energy sectors which affects the relative costs of alternative energies (for example, electricity potentially becoming more price competitive compared with piped natural gas).

D56 At the DPP3 reset we noted there was limited knowledge of consumer preferences toward natural gas, or what future sentiment will be.[183] As we discuss below, we are not aware of information that points to a material development since then.

D57 As part of reviewing GDB's demand forecasts, Concept Consulting considered the economics of switching from gas to electricity for residential and industrial customers.

D58 Concept concluded that for some uses (eg, residential new builds) electricity is already a more economic option than gas. However, Concept suggested that in practice, in a supply-constrained environment, industrial consumption would generally fall the fastest, eg, due to the lower costs for network owners in curtailing industrial demand.

D59 As discussed in Chapter 2, a scaling back or closure of some gas-dependent industrial operations due to input cost pressure and energy supply issues has occurred, and some medium and large users have been assessing options for switching.

GPBs are taking some action to address stranding risk

D60 Shortening regulatory asset lives supports a reasonable expectation of recovering the cost of past and future network investments. But it is not intended (or able) to guarantee full capital recovery for GPBs over the lifetimes of pipeline networks.

[181] See for instance: GasHub website.
[182] Actual switching will depend on the availability and attractiveness of alternative energy sources.
[183] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 3.51.

D61 If, for instance, demand drops quickly or a future government enforces restrictions on natural gas use, GPBs may be exposed to unmitigated stranding risk to the extent that the price increases required to recover their costs exceed consumers' willingness or ability to pay.[184]

D62 In DPP3 we considered this position to be consistent with promoting the long-term benefit of consumers, as it encourages GPBs to make prudent investments and take other actions to manage their exposure, which will likely benefit consumers.[185]

D63 Most GPBs are now considering network stranding risk as a factor to be considered in asset management planning, and the 2025 AMPs for most GPBs indicate that GPBs' understanding of network stranding risk is being applied to forecasting and decision-making processes over the AMP investment horizon.

D63.1 Our analysis of GPBs' forecasts of capex and opex for DPP4 is included in Attachments B and C. Some GPBs have reduced their capex forecasts, particularly in respect of system growth and gross connection spend, are more actively considering options for capex/opex substitution, and are reviewing their policies with respect to recovery of consumer connection costs.

D63.2 Powerco and Firstgas Distribution, as discussed in our Issues Paper, are considering, or are in the early stages of trialling, 'network rightsizing' practices which seek to withdraw unprofitable parts of existing pipeline networks from service – ie, where costs of maintaining and renewing part of the network are forecast to be greater than the revenues expected from connected customers (and are unlikely to be recovered from remaining customers, all else equal).[186]

D64 These actions are likely to have benefits for consumers in terms of lowering GPBs' net future whole-of-life costs to be recovered through pipeline charges and bolstering expectations—via improving the likelihood of cost recovery over time—of continuing the supplying gas pipeline services to satisfy consumer demand.

D65 Lastly, in our Issues Paper, we examined how GPBs translated the average asset life shortening specified at the DPP3 reset to the shortening of asset lives for particular assets in their 2023 ID RABs.[187] This had the potential to provide insights into how GPBs view the risk of stranding across various asset classes of subnetworks, which may lead to more targeted assessment and mitigation of stranding risk at upcoming resets.

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[184] We also noted in our DPP3 decision that the asset life adjustments we specified for DPP3 effectively deferred a portion of mitigation assessed at that time for consideration at DPP4: Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 6.57.

[185] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 6.58.

[186] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), paras E4-E19.

[187] The IMs for ID allow GPBs the flexibility to apply a greater or less extent of asset life shortening to particular assets in their RAB than the average adjustment specified in the DPP, so long as the total effect on depreciation under ID is equivalent to that in the DPP forecasts: GDB and GTB IMs, clause 2.2.8(5).

D65.1 We concluded that GPBs had generally targeted assets with longer remaining regulatory asset lives for asset life adjustments for ID purposes, and had generally not adjusted lives of non-network assets. In other respects, a largely undifferentiated approach was taken to adjusting individual asset lives.

D65.2 This may indicate that GPBs are still developing their understanding of how stranding risk relates to their business assets, including to asset (or subnetwork) characteristics such as location, function, nature of services supported, type of consumers supplied, or relationship with future costs.

D65.3 Alternatively, as we noted, it may be that GPBs have taken the view that stranding risk is not related to these characteristics, or that choices made over individual asset life adjustments for ID purposes do not impact on how risks can be managed or on stranding risk eventuating.[188]

What we heard from stakeholders

D66 We obtained views from interested persons in several ways, through submissions and feedback on our:

D66.1 Open Letter – where we outlined the context and process for the DPP4 reset;[189]

D66.2 Issues Paper – where we discussed the issues we considered relevant to, and the ways we proposed to set, the DPP4 price-quality path;[190] and

D66.3 Scenario modelling workshop – where we explored stakeholder views on updates to scenario modelling for changing industry circumstances since DPP3.[191]

D67 We also engaged with medium and large users, and held a korero with residential consumers and advocates.[192, 193]

[188] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), paras D19 – D26.
[189] Commerce Commission "Open letter on Gas DPP4 price-quality path reset" (13 February 2025).
[190] Commerce Commission "Gas DPP4 - Issues paper" (26 June 2025); Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025).
[191] Commerce Commission "Gas DPP4 2026 – Scenario modelling workshop" (15 July 2025); Commerce Commission "Gas DPP4 – Scenarios modelling workshop slides" (15 July 2025).
[192] Commerce Commission "What rising gas prices mean for NZ businesses: Insights from our discussions with medium to large gas users, as part of the reset of gas pipeline charges (Gas DPP4 2026)" (7 August 2025).
[193] Commerce Commission "Gas DPP4 Summary of Consumer kōrero - 22 Sept 2025" (20 November 2025).

Views on stranding risk at DPP4

D68 Many submitters on our Open Letter and Issues Paper stated that, in their view, the risk of network stranding had either increased relative to, or is less than, our DPP3 assessment due to factors affecting the commercial prospects for the gas industry.[194]

D69 The key factors cited by submitters were:

D69.1 Gas supply constraints – recent declines in domestic gas production and lower estimated future gas reserves;

D69.2 Continued uncertainty over government policy response to climate change and emissions; and

D69.3 Increasing availability and customer acceptance of renewable 'green' gases able to be conveyed in regulated pipelines.

Changes to our scenario modelling

D70 In our scenario modelling workshop held on 15 July 2025 we encouraged participants to articulate how the modelling assumptions, scenarios or scenario weightings in our long-term stranding scenario modelling could be changed to reflect new information.

D71 We invited participants and other interested persons to include specific suggestions in their Issues Paper submissions.

D72 Some submitters suggested that we consider an alternative set of industry scenarios, and/or a change in the weighting applied to the existing scenarios from DPP3. For example:

D72.1 Firstgas suggested we include a 2040 wind-down scenario driven by tight supply-side conditions and assign equal weight to that and the 2050 and 2060 scenarios.[195] Vector suggested we recognise a scenario with an early 2040s wind-down date, to acknowledge that GPBs could reach a cash flow negative position before 2050 and cease operations.[196]

D72.2 Methanex suggested including a longer-term wind-down scenario (eg, 2070) with some material weighting assigned to it due to possible availability of low

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[194] For example: Vector submitted that stranding risk has "heightened significantly" since the assessment undertaken at DPP3: Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 2; Powerco submitted that "[t]he risk of asset stranding continues to grow, hastened by the security of supply issue in 2024 and industrial customers looking to electrify more quickly as a result.": Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 14; Entrust submitted that a much higher rate of accelerated depreciation for DPP4 needed to prioritising early cost recovery of GPBs' prudent and efficient investment costs: Entrust "Submission on Gas DPP4 Issues paper, draft decision regulatory period paper; Fibre IM Review issues paper" (24 July 2025). MGUG submitted that stranding risk is overstated: MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), para 6; Methanex submitted that stranding risk is overestimated: Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 1.
[195] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 8; Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 6.
[196] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 7, para 77.

emission 'green' gases, and lower conveyed volumes being able to support long-term network operation for smaller users.[197]

D73 Some submitters on the Issues Paper also suggested changes be made to the technical parameters of the scenario modelling, such as altering the modelled profile of each scenario's long-term revenue trajectory. These submissions are discussed in later sections of this Attachment.

Concerns over affordability

D74 Lastly, we received a number of submissions suggesting we exercise caution if we were to further shorten regulatory asset lives for GPBs.[198]

D74.1 These submitters were concerned that recent cost pressures (including rising prices of delivered gas) may result in sub-optimal decisions by gas consumers to reduce consumption or exit the gas market in response to further material increases in pipeline charges for DPP4.

D74.2 Methanex submitted:

> Rapid escalation of pipeline fees threatens to exacerbate stranding risks, forestall opportunities for the development of renewable gases and potentially inadvertently engineer the 'death spiral' that the Commission is attempting to avoid.[199]

D74.3 MGUG submitted that further increases in pipeline charges in DPP4 are not sustainable.[200]

Our assessment taking into account stakeholder views

High levels of uncertainty remain and some sources of network stranding risk have evolved

D75 Considerable long-term uncertainty still exists at DPP4 over the pace at which gas usage will decline and/or the date at which gas pipeline networks may close:

D75.1 A significant long-term decline in natural gas usage, and a consequent material decline in the utilisation of regulated gas pipelines, is still expected to occur over the coming years/decades; and

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[197] Methanex submitted that adding an early wind-down scenario if a later one was also included is warranted, and assumed that an earlier wind-down scenario was assigned a low weighting: Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 5 – 8.

[198] Aluminium Extruders Association of New Zealand (ALENZ) "Submission on Gas DPP4 Open Letter" (12 March 2025); Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 1; Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 5; MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), paras 63 - 99; Nova Energy "Submission on Gas DPP4 Issues paper" (23 July 2025), p. 2.

[199] Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 3.

[200] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), paras 12, 99.

D75.2 There is currently no information that definitively narrows the wide range of possible profiles of decline in long-term demand, or provides clarity over whether some or all regulated networks may cease to convey natural gas.

D76 Despite overall uncertainty existing, the available information (including that received in stakeholder submissions) indicates that there has been some development in sources of risk since DPP3.

D77 We can assess the impact of these developments through reviewing the simplified long-term stranding modelling we used for DPP3. The modelling contains a number of scenarios, weightings and assumptions to estimate the extent of asset life shortening required at a price reset to maintain expectations of a credible long-term revenue trajectory and maintain investment incentives for the long-term benefit of consumers.

D78 As discussed above, in deciding to re-apply our stranding model at DPP4, the two modelled scenarios employed in the DPP3 reset (an industry wind-down at 2050 and 2060 respectively) appear to be reasonable starting points for reviewing current information and assessing the overall distribution of risk at DPP4.

Should our stranding model place more emphasis on an earlier wind-down scenario?

What we heard in submissions

D79 A key submission made by GPBs was that we should recognise an earlier industry wind-down scenario in our modelling to reflect the emergence of tight gas supply conditions.

D80 The impacts of tight supply-side conditions observed to date have been higher delivered gas prices (passing through higher wholesale gas prices to end-users) and increased spot price volatility,[201] which is likely contributing to the decline in short- and medium-term forecasts of demand relative to expectations at DPP3.

D80.1 Powerco submitted that "[g]as supply shocks and price increases have changed how some our largest customers view gas as a fuel and in some cases, these large customers are planning to reduce or end their use of gas earlier than they had previously planned."[202]

D80.2 The Joint submission from Firstgas, Powerco and Vector stated that security of supply is a growing concern for some users and "that some gas consumers have been unable to secure gas or only at high prices or only on short term contracts".[203]

[201] Particularly in respect of last year's 'dry winters' when gas is needed intermittently by electricity generators to meet demand for electricity.
[202] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 1.
[203] Firstgas, Powerco & Vector "Letter to the Commerce Commission – Response to Gas DPP4 Issues paper" (24 July 2025), p. 3.

D81 Firstgas submitted that the present tightening in gas supply due to a decline in known exploitable reserves was not forecast at the time of the DPP3 reset.[204]

D82 Entrust (a Vector shareholder) submitted that supply-side constraints mark a trajectory that will undermine demand for gas pipeline services, which will fall quicker than modelled and make it more difficult for GPBs to obtain financing and recover costs.[205]

D83 A counter view was provided by Methanex and MGUG which submitted that supply-side initiatives and/or government interventions could ensure continued long-term gas availability (for both large users and/or mass market consumers), and/or that future scarcity of gas was financially tolerable for GPBs.

D83.1 Methanex submitted that gas production constraints may prove to be temporary, or that future production may settle at a sustainable plateau to maintain sufficient pipeline revenues.[206]

D83.2 MGUG submitted that reduced consumption from tight gas supply conditions would not necessarily lead to increased stranding risk for GPBs, as "gas volume is a poor proxy for GPB revenue, and a poor proxy for stranding risk."[207]

D84 In addition, Vector submitted that a continuation of government policy uncertainty about the future of gas in the energy transition (and the impact on consumer behaviours) is a reason for recognising increased stranding risk at DPP4.[208]

Our assessment based on available information

D85 New Zealand relies solely on gas supply from domestic gas fields. Demand for gas pipeline services is derived from the demand for natural gas. It is possible that a supply-side shock could threaten GPBs' financial viability.

[204] See Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 4.
[205] Entrust "Submission on Gas DPP4 Issues paper, draft decision regulatory period paper; Fibre IM Review issues paper" (24 July 2025).
[206] Methanex also submitted that supply-side risks are not new and ought to already have been factored into GPBs' business models. Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 2-5.
[207] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), para 45. See also MGUG: "revenue is not driven by volume, so much as it is driven by consumer type and connections", MGUG "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 1.
[208] Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 3.

D86 At the time of our DPP3 decision we discussed the risk that future gas supply conditions could tighten, and that "potentially rising costs of developing new or additional natural gas reservoirs, and increasing difficulty of securing long-term contracts, may discourage the development of gas fields that is required to maintain production at current levels."[209] We noted that "possible uncertainty over gas supply, and potentially rising costs of wholesale gas due to higher costs of production, may discourage consumers from committing to the future use of gas."[210] Lastly, we highlighted the interdependencies between user groups (eg, industrial demand may underpin supply that also serves household and business customers) and that the sequencing of demand decline amongst those groups could bring about different consequences.[211]

D87 Latest projections of reserves in GIC's 2024 supply and demand study differ to those in GIC's 2022 study that we discussed at the DPP3 reset (and also differ to projections from other agencies at various points since the DPP3 reset).

D88 While the decline in reserves may not have been forecast at the DPP3 reset, we consider the source of the risk is the same as that we discussed at DPP3 – ie, discovering and producing sufficient reserves to meet current and future demand.

D88.1 In our DPP3 decision we discussed GIC's 2020 estimate of $300 to $500 million of investment needed every three to five years to bring existing reserves to market and maintain production levels. We noted the inherent uncertainties that surround future discoveries and production, the prospect of higher future production costs, and the risk that insufficient investment will be committed to discovering and producing reserves to ensure demand is met. The amounts involved now to secure sufficient gas to meet current demand may be considerably larger.

D88.2 To address supply-side needs, the current government has signalled various solutions including co-investment in offshore and onshore field development, and a potential LNG import terminal, each of which would help ease supply constraints and would be expected to stabilise gas wholesale prices (although average wholesale costs would likely be higher if the costs of sourcing gas were to be higher than today).

D89 In terms of the effect from the risk materialising, we assume that demand for bulk gas from industrial and large users would be most affected initially from supply-side constraints (due to a general inability to absorb large increases in cost inputs and/or scale back consumption) together with demand from 'marginal' mass-market customers whose consumption is most influenced by price.

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[209] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 3.3.4. See also, paras 3.53-3.55.
[210] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 3.3.5.
[211] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras 3.41-3.49.

D89.1 This seems to accord with reports of recent closures of the GTB's industrial customers[212] and the exit of some large users serviced by GDBs, and discussions with medium and large gas users – who report being price-sensitive as a result of their production processes, are facing significant cost pressures and operational challenges due to energy prices and limited energy supply options.[213]

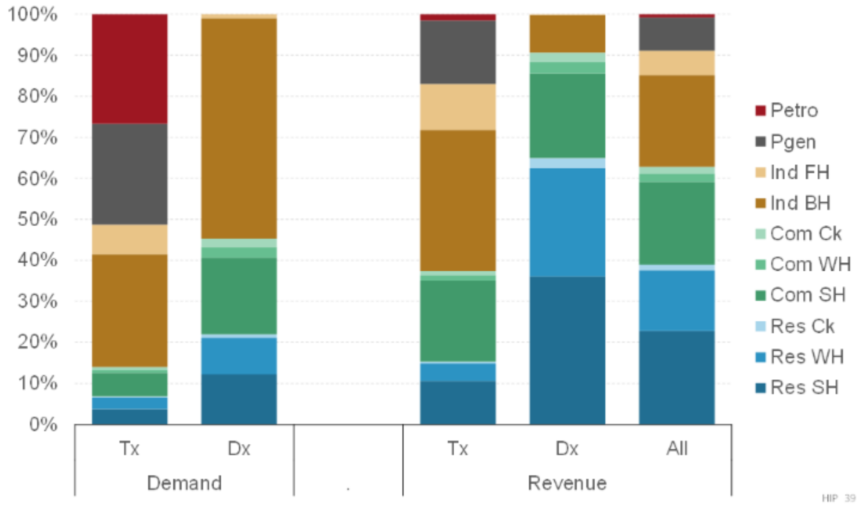
D89.2 As mentioned above, demand for mass market users served by GDBs now appears to have peaked (or will likely do so in the near-term) rather than continuing stable grow through DPP3 and into DPP4 as previously forecast by GPBs at the DPP3 reset.[214] This is consistent with our discussion in the DPP3 final decision, where we noted that any rise in forecast demand in DPP3 was likely to be short-lived, with an overall decline commencing thereafter.

D90 In light of revised short-term demand forecasts we have changed the MAR profile in the long-term stranding modelling for each of our modelled scenarios to align with short-term CPRG forecasts, commencing a downwards trajectory from 2027. We discuss this change in the section below on technical modelling parameters.

D91 The risk around supply shortages is likely still evolving. [215] However, even if appreciable declines in connection numbers were to occur in the short- to medium-term,[216] sufficient collective willingness and ability to pay required pipeline charges (as modelled in our stranding model for our two stranding scenarios) may still exist in respect of remaining customers. This may be particularly so in the case of the large number of households and small business customers who consume only a small proportion of total gas supplied but contribute the bulk of GDB revenues (Figure D1) due to the relatively high capital intensity of supplying small customers relative to the volumes they consume.

[212] See Chapter 2 of the Gas DPP4 Draft decision reasons paper (27 November 2025).
[213] Commerce Commission "What rising gas prices mean for NZ businesses: Insights from our discussions with medium to large gas users, as part of the reset of gas pipeline charges (Gas DPP4 2026)" (7 August 2025). See also Aluminium Extruders Association of New Zealand (ALENZ) "Submission on Gas DPP4 Open Letter" (12 March 2025).
[214] Vector stated that "connections and demand are both tracking significantly below forecasts used to set DPP3": Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), para 33.
[215] Firstgas notes that "gas supply could be higher due to the conversion of 2C resources, the importation of LNG or the production of biomethane, or could be lower due to well failures or early gas field closures": Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 4.
[216] Falling throughput in response to higher gas prices seems somewhat less of a concern as reductions in consumption may be reversible if supply conditions improve and consumers retain a connection (eg, if gas wholesale costs fall and/or consumer concerns over security of supply are addressed).

Figure D1 Sectoral split of gas demand and contribution to pipeline revenue



Source: Concept analysis drawing upon MBIE, Commerce Commission, First Gas, and EECA data

D92 The near-term effects of declining connections on pipeline viability would not be expected to be significant. Most of GPBs' pipeline costs are fixed (and therefore invariant to demand), and the gas customers who exit first in response the impact of tightening supply can be assumed to contribute relatively little to aggregate willingness and capacity to pay (despite large users consuming relatively high gas volumes) – see discussion of Figure D2 below. We have therefore assumed that the net loss of 'headroom' in willingness to pay above required revenues would be small.

D93 Longer-term, assuming the most price-sensitive large users and mass-market consumers continue to be the first to exit, we have assumed that adequate headroom in the collective willingness and capacity of gas consumers to pay would continue to exist, that is, willingness to pay would stay above the modelled profile of allowable revenues at all points.

D93.1 We model a linear decline in pipeline revenues required to support expectations of FCM in our 2050 wind-down scenario. Pipeline revenues under the scenario reduce, within 3 regulatory periods, to approximately 64% of 2027 allowable revenues (48% in real terms), and a shut-down of reticulated gas networks is assumed to occur within a total of 5 regulatory periods (including DPP4).[217] In the current context those assumptions seem suitably aggressive for modelling an early industry wind-down.

D93.2 The extent of collective willingness and capacity to pay was not known at the time of the DPP3 reset, nor are we aware of any data available to support a quantitative estimate ahead of DPP4. MGUG and Methanex have expressed concerns that higher pipeline charges for DPP3 have contributed to the decline in demand that is now being observed, but as we discuss below, we do not consider that the information presented establishes that current or future

[217] Assuming each regulatory period will be 5 years in duration.

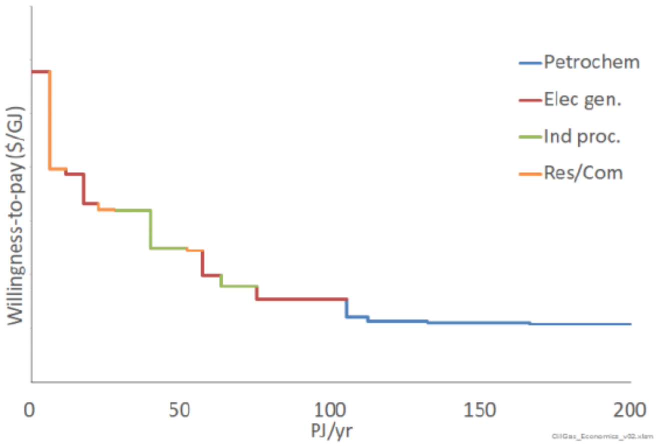
aggregate willingness to pay is likely being exhausted by the shortening of asset lives in DPP3.[218] In the absence of other information we continue to assume that the collective willingness to pay of consumers is sufficient to allow recovery of modelled pipeline charges in our modelled scenarios.

D94 On this basis we have concluded that supply-side constraints would need to be both major and sustained to adversely affect demand to an extent that threatens GPBs' financial viability under the assumptions used in modelling our wind-down scenarios.

D94.1 Considering customer composition and assumed willingness and ability to pay for the longer term we consider some portion of existing demand for residential space and water heating, and some small commercial customer use, could form a mainstay of future long-term viability for GPBs.

D94.2 An illustrative chart produced by Concept Consulting for GIC in 2019, and reproduced by Powerco in their Open Letter submission, depicted residential/commercial users as contributing some of the highest willingness to pay (Figure D2).[219]

Figure D2 Stylistic representation of the demand-curve for gas



D94.3 Additionally, some of these smaller customers may be suitable candidates for blended biomethane or other green gases that come online (albeit at a higher price reflecting higher production costs) to meet their future needs.[220]

D94.4 However, we note that Vector submitted that caution should be exercised in assuming that future mass-market demand would necessarily ensure future viability,[221] and the GIC has previously noted the concerns of industry

[218] At this point, we do not see significant value in attempting to quantify estimates of aggregate willingness to pay (and its likely trajectory over time in response to market conditions) given the extent of simplification in our modelling overall.
[219] Concept Consulting "Long-term gas supply and demand scenarios – 2019 update" (16 September 2019), p. 31; Powerco "Submission on Gas DPP4 Open Letter" (13 March 2025), p. 3.
[220] See GIC "Gas Supply and Demand Study 2024" (28 November 2024); Concept Consulting "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (prepared for the Commerce Commission, 22 August 2025).
[221] Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 5-8. See also Entrust "Cross-submission on Gas DPP4 Issues paper" (13 August 2025) , p. 3.

participants about the long- term viability of a domestic natural gas market at reduced scale.[222]

D95 As noted in our DPP3 decision there are likely to be differences and interdependencies between the customer group served by GPBs.

D95.1 As Figure D1 demonstrates, the composition of revenue sources differs between the GTB and GDBs, with the GTB currently heavily dependent on revenues from large industrial and power generation users. Declining revenues from industrial demand, or from electricity generators, would result in a greater future reliance of the GTB upon revenues from conveying gas to distribution networks. In this sense, the future composition and attributes of GDB customers are of importance to the GTB.

D95.2 We also note that GDBs differ with respect to proportions of customer segments served, and this may produce differences between GDBs in respect of exposure to stranding risk. For instance, Powerco has twice the proportion of energy delivered to residential connections than the other GDBs.[223] Significant regional variations may also exist, for example, in terms of the motivations for particular customer groups to connect to gas and stay connected.

D95.3 Sequencing of demand decline amongst customer groups could also produce different effects with respect to stranding risk. For instance, there is a possibility of a near-term retirement of the Maui gas field and a corresponding exit from New Zealand by Methanex, who is served by that field.[224] Depending on the timing and sequencing, we have assumed that this removal of a source of supply/demand from the gas market could:

D95.3.1 result in near-term excess supply from Maui (or other gas fields such as Pohokura or Kupe) being available via the GTB to other users, easing short- to medium-term wholesale gas prices; but

D95.3.2 have negative implications for long-term supply, affecting both GDBs and the GTB, as Methanex's departure would remove a major (and flexible) gas user who has previously underpinned gas field development.

[222] Gas Industry Company Limited "Gas Market industry Settings Investigation Consultation Paper (24 June 2021), p.36-37.
[223] See Concept Consulting "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (prepared for the Commerce Commission, 22 August 2025), p. 4.
[224] See, for example, The Post article.

D96 We have only limited information about the impact of differences and interdependencies between customer and have not attempted to incorporate them into our scenario modelling for DPP4.[225] However, these factors may become more relevant considerations if modelling were to be more tailored to a particular GPB (for instance as part of a CPP). At this stage, we have not attached a large degree of significance to a Maui/Methanex exit in our assessment of stranding risk at DPP4 but would be interested in receiving further information and views from stakeholders.

D97 We also note that, in response to revised demand forecasts and uncertainty, GPBs' AMP forecasts for capex and opex have changed relative to those existing at DPP3, and this has altered the long-term assumed trends of opex and capex in our stranding model. To the extent that future DPP expenditure allowances reflect these revised trends, then the present value of total future costs to be recovered through pipeline charges over time will reduce. GPBs are also considering initiatives (such as developing pro-active network rightsizing strategies) to optimise future costs and recoveries. This reduces the exposure of both networks and consumers to long-term stranding risks (all else equal).

D98 Lastly, with respect to other issues raised in submissions:

D98.1 MGUG submitted that connection data, gas price and consumption statistics indicate that higher DPP3 pipeline charges due to accelerated depreciation are contributing to the decline in gas demand that is now being observed.[226] GPB submitters responded by submitting that factors such as rising wholesale gas prices are affecting demand more significantly than accelerated depreciation in DPP3.[227] After reviewing the information submitted, we acknowledge that any increase in prices in the short term will affect demand and may lead to some consumer disconnections, particularly among those already considering switching away from gas. However, doing nothing would also likely have led to premature disconnections—if not during DPP3, then sometime after—as underinvestment would likely degrade service quality or make serving some or all customers uneconomic. Overall, we consider that taking action in DPP3 and continuing to address stranding risk in DPP4 should result in a higher level of continued connections over the long term than would have occurred under that counterfactual. Our view is that the risk of premature network closure is a more significant concern than short-term price responses when it comes to consumers continuing to access services they demand over the long term (s52(1)(b)). Consumers cannot benefit from a service if it no longer exists due to early closure. In our view, asset life shortening is not likely to lead to

[225] We note that the GIC Gas Supply and Demand Study 2024 modelled a 'Methanex exits immediately' scenario, although the objective of the study was not to assess risks to the financial viability of pipeline owners: GIC "Gas Supply and Demand Study 2024" (28 November 2024).
[226] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), pp. 2, 17-28.
[227] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 6; Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 9-11; Firstgas, Powerco & Vector "Letter to the Commerce Commission -Cross-submission on Gas DPP4 Issues paper" (14 August 2025); Firstgas, Powerco & Vector "Attachment A: Impact of AD on bills" (prepared by GIFWG)" (14 August 2025); Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), pp. 8-10.

"significant premature consumer disconnections during DPP3 or beyond".[228] Rather, it is intended to achieve the opposite outcome—maintaining network viability and ensuring continued access to gas services for consumers who remain willing to pay; and

D98.2 With respect to Vector's submission to place a greater emphasis on an earlier wind-down scenario due to continued uncertainty in government policy,[229] we explain in the next section that we do not see the long-term risks for the industry from that factor to be materially different at DPP4 to those faced at DPP3.

D99 In summary, based on the information available at this time, we consider that rolling-over our 2050 wind-down scenario from DPP3 (with a 33% weighting) as a central scenario in terms of the distribution of risks at DPP4 sufficiently recognises the risk of an industry wind-down by, or before, 2050, including earlier-than-forecast declines in demand due to supply-side factors and uncertainty over effects of government policy.

D100 As we noted above, we have responded to downwards revisions by GPBs to forecasts of consumer demand in our scenario modelling parameters by:

D100.1 Changing the MAR profile in the long-term stranding modelling to align with short-term CPRG forecasts, commencing a downwards trajectory from 2027; and

D100.2 Reflecting GPBs' revised opex/capex forecasts from 2025 AMPs in the opex/capex assumptions and long-term trends in our modelling.

D101 We accept that the risk of stranding associated with tight supply conditions could evolve further.[230] We can factor new information into our DPP4 final decisions in May 2026 (if information is available before then) or at the next DPP reset (ie, DPP5). If major developments occur during DPP4 then a GPB has the option of applying for a CPP (within the CPP application window) to tailor the price path to their particular circumstances and better meet the needs of the GPB and its consumers.[231]

[228] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), para D14.1.
[229] Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 3.
[230] For instance, an easing of supply conditions could lower wholesale prices and stem demand decline, and a near-term decision to close Methanex's methanol producing plant might be reversible in the future given the right conditions.
[231] A CPP also provides further flexibility for how assets can be depreciated, and for the provisions of the GDB or GTB IMs to be varied by agreement.

Should our stranding model place more emphasis on a later wind-down scenario?

What we heard in submissions

D102 MGUG and Methanex submitted that our modelling overstates the risk of gas use winding down by 2050 and/or the pace at which pipeline revenues are likely to decline,[232] and that significant pipeline revenues could be attainable by GPBs beyond 2060.

D102.1 MGUG and Methanex submitted that a strong future demand for natural gas (and thus for regulated gas pipeline services) could exist for energy consumers and that sufficient natural gas could be available to meet that demand.

D102.2 MGUG submitted that even on much lower volumes demanded or supplied, GPBs can still remain financially viable, including without accelerated depreciation.[233]

D103 Fonterra submitted that "continued regulation plus capacity to carry renewable gases implies a longer economic life for core pipeline assets, not shorter."[234]

Our assessment based on available information

D104 We consider it possible, as MGUG and Methanex have submitted, that natural gas could remain part of New Zealand's energy system beyond 2050 or 2060, consistent with the 2050 CCRA target for net zero carbon emissions – eg, if carbon offsets were available to support continued use.

D105 Longer-term reticulation of natural gas may provide net economic benefits to the New Zealand economy or to individual consumers, for instance, if utilised:

D105.1 as a long-term enabler for a national transition to alternative energies – avoiding inefficient/costly outcomes from a disorderly transition; or

D105.2 to satisfy ongoing energy demand by some users who are not yet ready or are not able to transition to low-emissions energy sources.

D106 In addition, some submitters—while not necessarily suggesting that natural gas would likely be used after 2050 or 2060—noted that significant value appears to be placed on gas by many existing users, including residential and small business consumers with respect to non-price features (such as speed, control and experience).

D106.1 Vector stated that its consumer research suggests that "many businesses do not have a viable alternative energy supply" and that for some users there is currently no alternative energy source that can accomplish the same thing as

[232] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), para 6; Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 1.
[233] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), para 41.
[234] Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 1.

gas does.[235] The Joint submission by Firstgas, Powerco and Vector states that their qualitative customer research findings point to gas being well regarded by households and small business users, even in the face of rising cost pressures (for gas and other costs of living).[236]

D106.2 Vector cited a number of studies suggesting that it is currently economic for some consumers to transition to electricity,[237] however the GIFWG noted that many consumers continue to use gas even although it would appear to make sense, economically, to switch to another energy source. The GIFWG notes that desirable non-price factors such as convenience (eg, instantaneous hot water) may play a role in this apparent consumer 'stickiness'.[238, 239]

D107 That significant value is placed on gas (as either an essential or desirable energy source) by many smaller users is consistent with the assumption, in general, of this customer segment having a high willingness and capacity to pay. As discussed in the previous section, it is conceivable that GPBs might remain financially viable for a long period of time on reduced volumes of gas conveyed to subsets of existing customers.

D108 Longer-term use beyond 2050 however, necessarily depends on there being sufficient gas supply available to support recovery of required pipeline charges, and a variety of views were provided by submitters in relation to possibilities for enabling imported or renewable gases to be conveyed within gas distribution networks to fulfil at least some future demand.

D108.1 MGUG noted that future gas demand could be satisfied by additional supply from additional domestic drilling, government support for further investment in exploration, LNG imports and availability of biogas;[240]

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[235] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 3.

[236] Firstgas, Powerco & Vector "Letter to the Commerce Commission – Response to Gas DPP4 Issues paper" (24 July 2025), p. 11- 12. See also Vector who states that its consumer research suggests "that residential gas consumers highly value their gas supply" Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 3.

[237] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), para 21.

[238] Firstgas, Powerco & Vector "Attachment B: Gas transition analysis paper" (prepared by GIFWG) (16 June 2023), p. 47. See also Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 2, who discussed the Pinstripe Leopard research where residential and business customers were "generally extremely positive about gas" although they expressed concerns about the cost of gas and its continued availability.

[239] Concept Consulting also observed that "... consumer behaviour appears to indicate significant non-price factors driving fuel choice decisions, including: perceptions of perceived quality variations between fuels; the 'hassle factor' associated with fuel switching; and environmental sentiments", Concept consulting "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (prepared for the Commerce Commission, August 2025), p. 13.

[240] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), para 41. MGUG noted additional possibilities of "regulatory evolution" and "network reconfiguration" would lower the risk. See also Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 5.

D108.2 Methanex noted that the "emergence of renewable gases and imported LNG could support pipeline revenues well beyond 2050".[241]

D108.3 Although some technical and commercial developments have occurred in processes for producing and blending biogas for distribution in New Zealand, Firstgas cautioned that larger production potential (or government support for large scale investment) has not been demonstrated.[242]

D108.4 Biomethane (or hydrogen) may not be likely to suit or be available to supply all mass-market customers,[243] and the higher cost of biomethane (compared to domestically sourced natural gas) may mean that other energy alternatives become more economic for some mass-market consumers.[244]

D108.5 Nova Energy noted that imported LNG, LPG and renewable natural gas (**RNG**) could offset declining domestic gas production.[245]

D108.6 The joint submission from Firstgas, Powerco and Vector indicated that a range of biomethane initiatives are being considered by industry, although the use of hydrogen is appearing less viable than at the DPP3 reset.[246]

D109 The GIC in its 2024 supply and demand study assumes some natural gas use past 2050.[247] In addition, the focus in ERP2 on enabling CCUS technologies (eg, enabling gas field operators to sequester carbon dioxide from their own production), and policy measures to facilitate the uptake of renewable gases such as biomethane, could also be expected to make it more likely that natural gas or blends could be conveyed by pipelines for longer. Lastly, we note that the Government's has signalled its support for industry-led investment in a renewable gas market in New Zealand in its Statement on Biogas announced on 22 October 2025.[248]

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[241] Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 6. See Ministry for the Environment "Our journey towards net zero: New Zealand's second emissions reduction plan 2026-30" (11 December 2024), p. 37.
[242] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 8.
[243] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 7.
[244] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 8.
[245] Nova Energy "Submission on Gas DPP4 Issues paper" (23 July 2025), p. 1.
[246] Firstgas, Powerco & Vector "Letter to the Commerce Commission – Response to Gas DPP4 Issues paper" (24 July 2025), pp. 3, 11, 13. We note that hydrogen scenarios do not feature in the later modelling of scenarios in the GIFWG stocktake of scenario modelling – Joint submission, Attachment A. No submitter commented on the relationship between potential future hydrogen use and the increased weighting of the 2060 wind-down scenario to reflect possible future residual value of pipelines.
[247] GIC "Gas Supply and Demand Study 2024" (28 November 2024).
[248] MBIE "Government Statement on Biogas" (October 2025).

D110 Whether longer-term gas use can be sustained, will also turn on the economics affecting consumers decisions (over time) to switch to alternative energy sources and changes in consumer preferences (eg, willingness to pay in light of environmental or health concerns)[249] A range of views was provided by submitters, but our conclusion is that the developments in these areas have not yet altered materially relative to DPP3.

D111 Lastly, longer-term use of reticulated gas will also depend on future government policy measures.

D111.1 As mentioned above, in DPP3 we had expected some specific developments in government policy which may have increased certainty around the overall transition timeframes for gas in New Zealand, but these were not completed. Current government policy is more supportive toward gas exploration and investigating options for supply-side security.

D111.2 There has been no cross-party agreement on long-term decarbonisation pathways for fossil energies or network closures, including if, and to what extent natural gas use would be retained in use past 2050. Methanex submitted that there is a "likelihood that policy interpretations and preferences will continue to fluctuate back and forth with each election cycle."

D112 At the DPP3 reset, we recognised that natural gas:[250]

D112.1 may have an important role as a transitional energy source and/or as a potential supplement to renewable but intermittent energy sources;

D112.2 is an essential energy source for many homes and businesses and switching to lower-emissions alternatives for residential, commercial, and agricultural users is unlikely to be sudden (as it involves thousands of consumers making decisions around capital expenditure for appliances and installation);

D112.3 seems capable of being blended with renewable gases such as biomethane and hydrogen (to help meet demand from some users) and industry participants had signalled moves to undertake trials; and

D112.4 may still be needed as part of the energy mix in 2050, and that a number of industry forecasts at the time assumed gas use continues to or beyond 2050.

D113 These factors seem as relevant to our risk assessment today as they did at the DPP3 reset. We also note that a primary reason for introducing the 2060 wind down scenario as part of our DPP3 final decisions was to recognise the possibility of some level of reticulated gas use past the 2050 CCRA net zero target, and was heavily weighted (67%) as part of the distribution of risk.

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[249] For health implications see, for instance: EECA "Indoor Combustion in New Zealand Homes: Health Effects and Costs"(September 2024)

[250] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), chapter 3.

D114 In the absence of evidence or information showing any significant change in factors affecting the likelihood of reticulated gas use beyond the 2050 CCRA target for net zero carbon emissions, we consider that rolling-over a 2060 wind-down scenario (with a 67% weighting) appropriately recognises the present possibility of some material level of gas use beyond 2050 or 2060.

We consider DPP3 scenarios remain fit-for-purpose at DPP4

D115 After considering the information available (including that contained in stakeholder submissions), our draft decision is not to include a wind-down scenario earlier than 2050, or later than 2060, in our long-term network stranding model, nor adjust the existing scenario weightings to place greater or less emphasis on either of the two scenarios rolled-over from DPP3.

D116 We consider this approach remains compatible with the evolving risk profile at this time and is appropriate for setting DPP4. Specifically, despite risk from different sources having changed to some extent since the DPP3 reset, we consider the two modelled scenarios we used in DPP3 remain central in the distribution of risks and are plausible and reasonable ones for the DPP4 context.

D117 Re-applying the DPP3 network stranding model to DPP4 effectively completes the transition to shorter asset lives that we started in DPP3 to mitigate stranding risk.

Updates to technical parameters of stranding model

D118 As signalled in our Issues paper, we have updated building block cost variables and considered changes to other technical parameters in our network stranding model we first used in DPP3. Key changes from the DPP3 model are described below.

We have updated long-term building block cost inputs

D119 In rolling over the two wind-down scenarios from the DPP3 stranding model to inform our assessment of stranding risk and mitigation at DPP4, we have updated our long-term building blocks cost inputs to reflect the most up-to-date information.

D119.1 The WACC estimate we use for DPP4 and associated estimation parameters are applied as the long-term stranding model cost of capital inputs.

D119.2 Opening RAB values and regulatory remaining asset lives used to depreciate existing assets in the stranding model are sourced from 2024 ID data and RFI responses from GPBs.[251]

D120 In addition, we have adjusted the profiles of assumed long-term opex and capex:

D120.1 Values for DPP4 (2027 – 2031) align with our draft opex/capex allowances;

[251] These reflect the adjustment of regulatory asset lives by GPBs for the 2023 disclosure year for ID purposes as a result of our DPP3 decision to shorten average asset lives for all GPBs. See clause 2.2.8(5) of the GDB and GTB IMs.

D120.2 Values for the following 4 years (2032 – 2035) are sourced from GPB's 2025 AMPs with adjustments;

D120.3 Values then decline, linearly, to an endpoint:

D120.3.1 For opex, we specify the end point as 30% of 2027 opex, occurring at the relevant scenario wind-down date.[252]

D120.3.2 For capex, we specify the end point as 20% of the average values (actual or forecast) in DPP3 (2023 – 2026), occurring at the earlier of 15 years after the last AMP forecast value or the relevant scenario wind-down date, whichever arises first, with flat projections adopted after that if required by the scenario.

D121 This approach for opex and capex is consistent with that we adopted at DPP3, including the removal of costs attributable to asset relocation, system growth and consumer connection (net of capital contributions) from capex for all GPBs.

D122 Some submitters suggested that potential costs of future long-term eventual network decommissioning were material and should be allowed for as part of the DPP4 price path (eg, as a specific allowance). This issue is discussed in Attachment F.

We have revised the near-term profile of the long-term revenue trajectory

D123 For both of the modelled scenarios, we have altered the profile of the first 5 years of the long-term revenue trajectory for GDBs to reflect declining demand (**CPRG**) forecasts for GDBs in DPP4 (and removed the 2-year ramp-up that had previously been modelled for DPP4). This replaces the assumptions we had made at DPP3 for 2027 – 2031 with information that we have used to set DPP4 allowable revenues.[253]

D124 For the 2060 scenario we have retained the moderate (2%) concave revenue profile assumption, and applied it with effect from the first year of DPP4 (2027).[254] Applying the concave profile recognises a possible greater ability of future remaining consumers to absorb price increases than those existing in the near-term (including during DPP4).

[252] Since the long-term trend for opex is essentially determined by the forecast value for a single year (2027), and movements in that year can have a large effect on future projected BBM costs to recover, we may consider changing that method ahead of the final decision, eg, aligning it with the method for capex to reduce sensitivities.

[253] We have therefore accepted Vector's submission to remove the ramp-up period (Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 26), and not accepted Firstgas' submission to extend the revenue increases from the ramp up period in DPP3 to the end of DPP4 (Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 8.

[254] The 2% concave revenue profile is overlaid on the declining demand (CPRG) forecasts for the five-year DPP4 period (ie, the modelled revenue profile for a 2060 wind-down is affected by both the concave revenue profile and CPRG in DPP4).

D125 Methanex suggested that we more comprehensively analyse customer characteristics to establish a revenue profile (such as an S-shaped revenue curve) that might better reflect aggregate willingness to pay (rather than a wholly linear or simple concave curve).[255] We consider this may be more important refinement at future resets (provided suitable data or estimates were available) but have not treated it as a priority for the DPP4 reset. We note that a more accurate depiction of consumer willingness to pay such as this could form part of a CPP application.

D126 We have retained the assumption under both scenarios that allowable revenues at the wind-down date equals 20% of 2023 MAR.[256] This recognises that if network operations were to cease, some aggregate willingness to pay would likely still exist at that point. In other words, networks would likely become uneconomic to operate even if some material level of customer demand for continued service existed.

Our weighted scenarios form the central distribution of risk

D127 We emphasise that the objective of our stranding modelling was not to determine the likely future end-state of the gas industry, but to assess the extent of regulatory action at DPP4 that best promotes the long-term benefit of consumers of gas pipeline services under a range of plausible future outcomes.

D128 The 2050 and 2060 wind-down scenarios represent our estimate of the central distribution of risk, but they do not imply that we expect gas networks to necessarily cease by either of those dates. In particular, the inclusion of our 2060 scenario as the longest modelled wind-down scenario does not imply a 100% likelihood of network closure by that date.[257] A risk also remains of full or partial closure of networks before the date modelled by our 2050 wind-down scenario.

D129 The scenario modelling is a tool that estimates depreciation adjustments required in a particular DPP period to align GPBs with an overall long-term revenue trajectory consistent with FCM. If our stranding model is re-applied at future DPP resets (or as part of a CPP), the long-term revenue trajectory will be subject to re-estimation to take account of the most relevant information, including the latest view of any possible industry wind-down dates.

[255] Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), pp. 7-8.
[256] Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 26.
[257] See Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025) , pp. 1, 8.

Attachment E Quality standards

Purpose of this attachment

E1 This chapter sets out our draft decisions on quality standards, and outlines what we have considered in coming to these decisions for GDBs and the GTB.

The Act requires us to set quality standards for regulated gas pipeline businesses

E2 We set quality standards for GPBs while setting a default price-quality path as required by the Act. The provisions of the Act that are directly relevant to gas quality standards are:

E2.1 Section 52A(1)(b) – sets out incentives to improve efficiency and provide services at a quality that reflects consumer demand. It is the most relevant subsection of the Part 4 purpose when it comes to quality standards.

E2.2 Section 53K – sets out the purpose of default/customised price-quality regulation. It states that default price-quality paths should be set in a relatively low-cost way.

E2.3 Section 53M(1)(b) – requires us to set quality standards when setting a DPP. At the same time, we have wide flexibility, with s 53M(3) allowing us to set quality standards in any way we consider appropriate.

E2.4 Section 53M(2) – price-quality paths may provide incentives for suppliers to maintain or improve quality of supply. Incentives may include, but are not limited to: penalties, rewards, consumer compensation, and reporting requirements.

Our draft decision is to retain the current quality standards

E3 Our draft decision is to retain the current quality standards that apply to the GPBs. To meet the quality standards:

E3.1 for the GTB and GDBs, the time taken to respond to any emergency must be less than 180 minutes;

E3.2 for the GTB and GDBs, the percentage of emergency responses taking longer than 60 minutes must not be greater than 20%;

E3.3 the number of major interruptions for the GTB must not exceed zero; and

E3.4 if there is a major interruption, that the GTB must provide a detailed publicly available report.

E4 Our draft decision is not to introduce new quality standards for the GTB and GDBs for DPP4.

Our reasons for this draft decision

E5 In reaching our draft decision our reasons for not making a change to the present gas quality settings include that:

E5.1 GPB reliability and quality outcomes have not significantly worsened over time. The total number of outages, emergencies experienced by customers, and the resulting number of complaints have either remained stable or decreased;

E5.2 There are other regulations and incentives that ensure that GPBs maintain quality of service such as the Gas Act 1992, the Gas (Safety and Measurement) Regulations 2010, and the Gas Governance (Critical Contingency Management) Regulations 2008. GPBs also have commercial incentives to maintain their quality of service such as:

E5.2.1 the reputational impact of quality problems;

E5.2.2 the costs involved in responding to and repairing any damage; and

E5.2.3 the revenue lost from undelivered services during an interruption.

E5.3 we are not satisfied we need to change the quality standards because the current quality standards are fit for purpose.

E6 In addition, stakeholder feedback to our Issues Paper did not identify that a change was necessary.

E7 Based on our analysis, we consider that the current quality standards are promoting the long-term benefit of consumers and the provision of services at a quality they demand. We consider the standards do not need to be changed, although we will continue monitoring gas quality and metrics using ID data over DPP4.

Gas sector quality outcomes are relatively stable

E8 In the Gas DPP4 Issues Paper we noted that our recently published report on GPB performance, concluded that, in general, gas sector quality performance has either been stable or improving.[258]

E9 Since the Gas DPP3 commenced on 31 May 2022, all GDBs and the GTB have met the DPP3 quality standards.

E10 In our Issues Paper we presented some analysis and noted that while none of the observed individual GPB quality trends appear to justify additional quality measures at this point, some GPB quality performance metrics may need to be monitored more closely in the future.[259]

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[258] Commerce Commission, Trends in gas pipeline businesses' performance, 18 Feb 2025, available here.

[259] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), para A74-A106.

E11 For example, we noted that:

E11.1 Powerco's CAIDI has been steadily worsening since 2013. CAIDI is the average time it takes to restore service to customers following an outage. An increasing CAIDI trend indicates customers subject to outages are on average without supply for longer; and

E11.2 Firstgas Transmission detected gas leaks, emergencies and incidents relating to gas specification, all appear to be trending upwards although incidents are not numerous over the period analysed and due to the limited data set its not clear this is a trend.

E12 Additionally, as a threshold for change, we would need to be convinced that imposing any new quality measure promotes the long-term benefit of consumers. One relevant consideration is whether the value a new quality measure provides exceeds the cost including the complexity of implementing and administering it.

There are other regulatory measures and commercial incentives driving gas sector reliability

E13 Gas pipelines are subject to a wide range of regulation, in addition to Part 4 of the Commerce Act 1986 that we administer.

E14 Other regulatory agencies also have responsibilities for the natural gas industry. The Gas Industry Company (**GIC**) is the natural gas industry's co-regulator, established under the Gas Act 1992.[260] It is responsible for administering governance arrangements for the downstream natural gas industry from processing through to retail.

E15 MBIE has a central role in governing, monitoring, and advising on the wider natural gas market, and assessing recommendations made by the GIC.

E16 WorkSafe New Zealand is responsible for the Health and Safety in Employment (Pipelines) Regulations 1999.[261] It is also responsible for monitoring and enforcement of safety standards set out in the Gas Act (or within regulations made under the Gas Act).

E17 GPBs are also incentivised to avoid problems with the quality of the regulated service because of commercial incentives like:

E17.1 the reputational impact of quality problems;

E17.2 the costs involved in responding to and repairing any damage; and

E17.3 the revenue lost from undelivered services during an interruption for GDBs.

[260] The Gas Act 1992, available here.
[261] Health and Safety in Employment (Pipelines) Regulations 1999, available here.

We are not satisfied we need to change the quality standards because the current quality standards are fit for purpose

Our analysis shows that the current quality standards are fit for purpose.

E18 In general, GPB reliability and quality outcomes have not significantly worsened over time. The total number of outages, emergencies experienced by customers, and the resulting number of complaints have either remained stable or decreased.

E19 There are other regulations and incentives that ensure that GPBs maintain quality of service such as the Gas Act 1992, the Gas (Safety and Measurement) Regulations 2010, and the Gas Governance (Critical Contingency Management) Regulations 2008. GPBs also have commercial incentives to maintain their quality of service such as:

E19.1 the reputational impact of quality problems;

E19.2 the costs involved in responding to and repairing any damage; and

E19.3 the revenue lost from undelivered services during an interruption.

E20 Based on our analysis, we consider that the current quality standards are promoting the long-term benefit of consumers and the provision of services at a quality they demand. We consider the standards do not need to be changed, although we will continue monitoring gas quality and metrics using ID data over DPP4.

GTB Major interruptions quality standard

E21 In response to our Issues Paper, Firstgas proposed a change to the major interruptions quality standard to amend the definition of major interruptions to exclude small events or localised contingencies. It submitted that the current drafting inadvertently risks capturing events that are not major interruptions.[262]

E22 Firstgas' view is that these circumstances can occur in very localised events, highlighting an event where gas supply was lost to a small number of gas users at the Mount Maunganui delivery point. In that event, Firstgas submitted that a major interruption was only avoided as local gas users voluntarily reduced demand.

E23 Firstgas states that it does not consider that we intended the standard to apply to localised events. It proposed addressing this by introducing a minimum number of customers or gas volume that need to be affected by a major interruption.

E24 We introduced the major interruptions standard in DPP2 as we were concerned that there was inadequate accountability for suppliers following major interruptions. We noted that:[263]

[262] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.38.
[263] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 7.17, p.76.

While interruptions in gas transmission are rare, they can have a large impact when they do occur. In our view, introducing an interruptions standard is an appropriate measure to incentivise GTBs to maintain reliable gas transmission.

E25 The quality standard we set captures any significant interruption in the supply of services on the transmission network. More specifically, the quality standard is linked to critical contingencies that result in curtailments.

E26 In the Firstgas example, a gas curtailment directive was not made because there was a voluntary reduction in demand In the absence of more information, we do not know what impact this event would have had without the voluntary load curtailment. Accordingly, we are not satisfied that this example shows that the standard is not fit for purpose.

E27 In our view there is insufficient information to make a change, and there is no evidence about what constitutes a reasonable minimum threshold of a 'small number of customers' or gas volumes.

E28 In the absence of this information, and where a threshold would appear to be an arbitrary setting, our draft decision is that the GTB major interruption quality standard remain unchanged

E29 Our view is that this quality standard should remain guided by the Gas Governance (Critical Contingency Management) Regulations 2008, that set out how and when gas curtailment directives are issued, regardless of gas volumes or customer numbers.

Other quality matters raised in stakeholder submissions

E30 Other quality matters were raised in submissions on our Issues Paper. We outline these below and how have addressed these.

Disconnections

E31 The Major Gas Users Group (**MGUG**) submitted that a new standard is required to provide for affordable and timely exit off the gas network.[264]

E32 Rewiring Aotearoa (**RA**) submitted recommending that we introduce regulations to protect consumers and guarantee the quality of disconnections.[265]

E33 Firstgas in its cross-submission support ongoing monitoring of GDB disconnection pricing and policies, while retaining the flexibility of existing arrangements.[266]

E34 Consumer NZ expressed concern with the high costs for customers of disconnecting. Households face significant costs, often between $1,000 and $2,000, to have gas meters permanently removed.[267]

[264] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), p.5.
[265] Rewiring Aotearoa "Submission on Gas DPP4 Issues paper" (24 July 2025), p.8.
[266] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), pp.15-17
[267] ConsumerNZ "Submission on Gas DPP4 Issues paper" (24 July 2025), p.2.

E35 We have reviewed submitter concerns over disconnection quality outcomes. This may become an increasingly important area as consumers switch to alternative sustainable sources of energy in larger numbers and parts of networks become uneconomic to maintain.

E36 Stakeholder submissions on disconnections have revealed that there is some confusion about the types of disconnection and who is responsible for disconnection costs.[268] Disconnections are likely to become an increasing area of focus for gas pipeline users as they consider leaving the network.

E37 Given the expected increase in customers disconnecting from the gas networks, we expect disconnections to become an emerging focus over DPP4. We have not specifically considered disconnection issues in the past. As the gas networks have been growing, we have not seen large numbers of disconnections and there has been limited focus on the costs and activities related to disconnections.

E38 We consider that the first step is to collect information on disconnections and monitor outcomes. We will consult on any information disclosure requirements in due course. This will increase transparency on how disconnections are being carried out and help inform us and stakeholders on whether quality standards should be set in future.

Customer Average Interruption Duration Index (CAIDI)

E39 In our issues paper we considered if certain metrics such as Customer Average Interruption Duration Index (**CAIDI**) should be monitored more closely. We require CAIDI to be disclosed by GDBs under information disclosure regulation.

E40 Our preliminary analysis showed that there has been a moderate decline in CAIDI performance for Powerco from 2013 to 2023.[269]

E41 Powerco submitted that CAIDI is not a good measure to indicate whether quality deterioration is occurring across the customer base. They further submit that there aren't sufficient outages in gas to accurately capture an overall quality deterioration and that it includes interruptions such as slips in Wellington due to weather events.[270]

E42 Powerco also submitted that we did not include data for 2024 in our Issues Paper analysis which showed a decrease in CAIDI.[271]

E43 CAIDI is a key measure to understand how quickly a supplier restores service after an interruption. It helps them identify areas where restoration processes need improvement and allows them to prioritise investments in infrastructure or procedures to reduce interruption durations.

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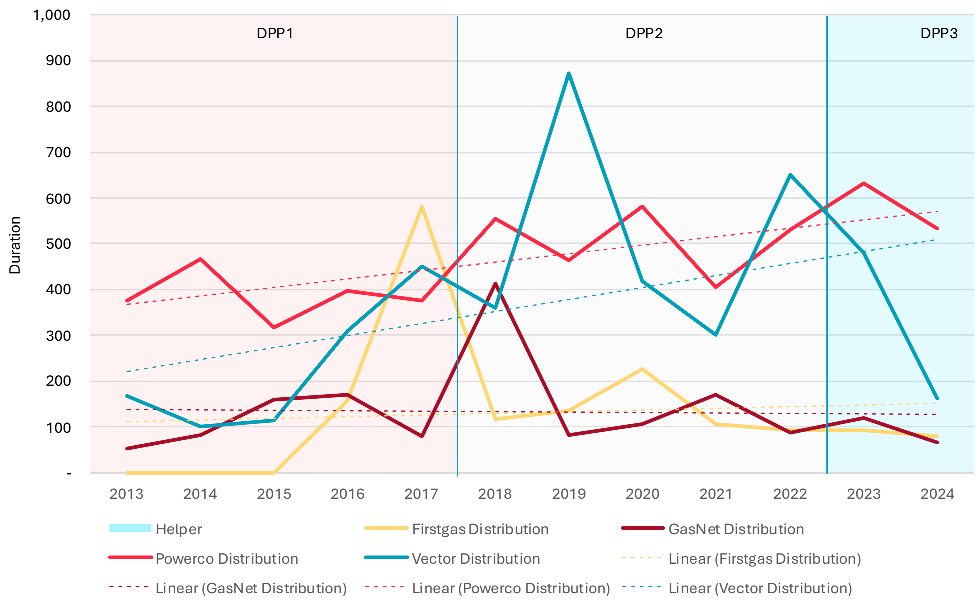
[268] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p.15.
[269] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), Figure A4, p.22.
[270] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), para 2.3.
[271] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), Figure 3, p.9.

E44 CAIDI is defined as;

$$CAIDI = \frac{sum\ of\ all\ consumer\ interruption\ durations}{number\ of\ all\ consumer\ interruptions} = \frac{SAIDI}{SAIFI}$$

Figure E1 CAIDI Class C interruptions by year



E45 We updated the CAIDI analysis since our Issues paper was published and included 2024 ID data. Figure E1 now includes data for 2024 and shows consistent performance from 2013 to 2024 for each of Firstgas Distribution, GasNet, and Vector.

E46 Despite Powerco's performance, which suggests that the time taken to restore supply, following outages on its network, appears to be increasing over time, we are of the view that a new CAIDI quality standard is not presently supported.

E47 The simple trend line analysis depends on a small data set and a limited number of outages. We also note that the CAIDI outcome fluctuates significantly year on year which may be due to the limited number of outages across Powerco's wider network and the differing outage response times that the CAIDI metric is revealing.

E48 However, we will continue to monitor CAIDI performance through ID when more data becomes available, as it may provide more insight into potential unreliability in uneconomic parts of networks, or a conclusion that outage response times are increasing.

Gas leaks

E49 In our Issues paper we presented preliminary analysis of GTB reliability metrics using ID data and observed that since 2017, the number of gas leaks detected was trending upwards.[272] We raised the possibility of a gas leak quality standard.

E50 In its Issues paper submission Firstgas noted that it did not believe that the benefit of a gas leak quality standard would outweigh the costs. Firstgas also stated that it already has strong incentives to minimise leaks including through:[273]

E50.1 "the existing quality standard requiring a timely response to gas emergencies"; and

E50.2 "emissions reduction target to 2030, and gas leaks run counter to that target."

E51 Firstgas further noted that since 2018, while there has been a slight upwards trend in the number of gas leaks detected, "the overall count remains low with an average of 1.5 events per month and the 2018 year is the highest in this period" noting that the 2020 and 2021 gas leak were lower "because of reduced opportunities to detect leaks during periods of pandemic lockdowns when staff movements were restricted or minimised."

E52 Firstgas also noted in its submission that gas leaks rarely result in loss of supply and that 'gas leaks leading to loss of supply' would be a better measure of gas network reliability:[274]

> The difference between the overall number of gas leaks, less the number of gas leaks which did not result in disruption to supply, would indicate how many leaks have resulted in disruption to supply. Arguably, this is the measure that is most relevant. Since 2018, there have been no events of this nature for Firstgas transmission.

E53 Our draft decision is that there is insufficient evidence to justify a quality standard at this time. However, we will continue to monitor gas leaks over DPP4 to see if these stabilise or continue to increase.

E54 In its Issues Paper submission, Firstgas observe that the Input Methodologies do not define exactly what a gas leak is, but that it has its own definition of gas leak:[275]

> A reported uncontrolled release of gas from the Firstgas Transmission System. Firstgas does not consider minor leaks found and remedied as part of normal operation, as reportable. Firstgas will only report gas leaks that based on the experience and training of the maintenance technician or operator, have the potential to cause an Emergency or Interruption or Incident

[272] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), Figure A5, p.22.
[273] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.21.
[274] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.22.
[275] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.38.

E55 Our view is that the Firstgas definition of gas leak is reasonable as it ties the impact of the leak (that it has the potential to cause an Emergency or Interruption) to our existing quality standards for the GTB (response time to emergencies and no major interruptions on the transmission network).

E56 Firstgas is governed by other regulations and incentives that ensure that GPBs maintain quality of service and to ensure safety. While Firstgas does not consider a gas leak quality standard is warranted, as it has strong incentives to reduce leaks through the existing standards, we feel that it necessary to clarify the definition of gas leak and not leave this definition to supplier discretion.

E57 Having considered the Firstgas submission, and to enable consistent monitoring of gas leaks over DPP4 and beyond, we consider that the following is a reasonable definition of a transmission network gas leak:

> a gas leak is defined as an escape of natural gas from gas infrastructure assets, which has the potential to cause an emergency, interruption or incident.

E58 We will consider making an ID amendment to define gas leak in line with the Firstgas definition and seek stakeholder views on this change.

Attachment F Future issues not affecting our DPP4 draft decisions

Purpose of this attachment

F1 The purpose of this attachment is to describe issues raised by submitters during our DPP4 consultation process which we have considered, but which have not affected our draft decisions for DPP4. We recognise that these issues could play a role in the development of regulatory policy for future price-quality paths or other Part 4 regulation.

F2 The four issues are:

F2.1 the treatment of future network rightsizing practices;

F2.2 the treatment of potential large-scale future network decommissioning costs;

F2.3 the treatment of non-depreciable easements; and

F2.4 a proposed cross-sector solution for addressing the impact of declining demand for gas pipeline services.

Structure of this attachment

F3 In Table F1 we describe the structure of this attachment.

Table F1 Structure of this attachment

Title	Description of content
Purpose of this attachment	Sets out the purpose of this attachment, what it covers, and how it is structured.
Regulatory treatment of network rightsizing	Why Part 4 (and other consumer-related) issues for network rightsizing will be considered in a process separate to the DPP4 reset.
Potential large-scale future network decommissioning costs	Why we are not making a specific allowance for potential future large-scale network decommissioning costs (or changing any other existing regulatory setting) in DPP4.
Non-depreciable easements	Why we are deferring consideration of the depreciation treatment of easements until after the DPP4 reset.
Cross-sector solution for addressing the impact of declining demand	Why a proposed conceptual solution identified by Greymouth Gas is out of scope for the DPP4 reset.

Regulatory treatment of network rightsizing

F4 Consistent with our Issues paper, we will consider network rightsizing as part of a regulatory process separate to the DPP4 reset process. We noted in the Issues paper that any regulatory response to network rightsizing might require amendments to the GDB and GTB IMs. For this reason, all or part of our consideration of the Part 4 issues might be best co-ordinated as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest).[276]

F5 Powerco supported deferring consideration of network rightsizing issues, noting:[277]

> For Powerco, these are not material or urgent enough at this time, but should we see evidence of this changing over DPP4, we encourage the Commission to be open to addressing this in DPP5. As proposed in the Issues paper, we support a separate regulatory project to look at network rightsizing in advance of DPP5.

F6 MGUG submitted that GPBs are not prevented from pursuing network rightsizing strategies. However, MGUG suggested we consider requiring approval for a GPB to remove service:[278]

> We do however consider that the Commission should follow AER practice to require approval from the Commission if GPBs seeks to remove or disable any part of its pipeline system that supplies gas to one or more customers for any reason.

F7 As we noted in our Issues paper, regulatory policy issues may arise in relation to future network rightsizing practices undertaken by GPBs. However, we understand rightsizing practices have not yet been implemented by any GPB, and that plans to do so are still in their formative stages. As such, we consider network rightsizing unlikely to be a material consideration for the DPP4 reset.

F8 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 consumers 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).

F9 We do not currently have the ability to develop a withdrawal code for GPBs. We will engage with policy agencies to highlight this emerging issue and consider whether appropriate protections are needed for consumers.

Potential large-scale future network decommissioning costs

F10 We are not making a specific allowance for large-scale future decommissioning costs or changing any existing regulatory setting for DPP4 in respect of this issue.

[276] Commerce Commission "Gas DPP4 - Issues paper" (26 June 2025), paras 2.31 – 2.33; Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), paras E4 – E19.
[277] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 11.
[278] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 7.

F11 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.

F12 We may consider the treatment as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest) or as part of DPP5, when further information and greater clarity for the gas sector may have emerged.

Considering future network decommissioning costs

F13 The treatment of costs involved with the potential large-scale future decommissioning of gas networks under our BBM framework has not been raised substantively at any previous gas DPP reset, nor considered for any other sector that we regulate.

F14 In our Issues paper, we considered that a main challenge we faced in considering the implications of eventual network decommissioning under Part 4 regulation was the high degree of uncertainty over the nature of decommissioning liabilities, and the type/scale of costs involved for GPBs.

F14.1 Requirements and processes around decommissioning are not yet well defined or understood. Further, the legal or other basis on which GPBs would incur costs (and the possible contribution to those costs by other parties) is unclear.

F14.2 There is no reliable estimate of the costs involved or when they would likely be incurred. The costs may vary across GPBs, depend on the state of their networks at the time of retirement, and decommissioning may be progressive.

F15 In addition, we noted the novel nature of some of the solutions discussed by submitters on our Open Letter (eg, establishment of a ringfenced industry decommissioning fund) and that further consideration would be required about how, if these ideas were implemented, they would interface, legally and practically, with our regulatory regime.

Views of stakeholders

F16 Firstgas and Vector submitted that acting now to address this issue is important while the overall customer base is at its broadest, even in the face of uncertainties.[279]

[279] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), pp. 17-20; Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), pp. 2, 22-23; Vector "Submission on Gas DPP4 Issues paper" (24 July 2025), pp. 6-8; 36-39; Vector "Attachment A: Key issues for Gas DPP4 reset report" (prepared by Frontier Economics) (24 July 2025), pp. 34-37; Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), pp. 17-19. See also: Entrust "Submission on Gas DPP4 Issues paper, draft decision regulatory period paper; Fibre IM Review issues paper" (24 July 2025); Entrust "Cross-submission on Gas DPP4 Issues paper" (13 August 2025).

F17 The Joint submission from Firstgas, Powerco and Vector noted that early exploration of this issue and possible options during DPP4 is desirable.[280] Powerco encouraged the Commission to explore the issue more broadly during DPP4.[281]

F18 Methanex queried whether the risks/costs of decommissioning have already been internalised by GPBs as part of decisions to purchase businesses or install new assets.[282]

F19 MGUG queried whether providing for these costs in the BBM framework undermines incentives to defer abandonment which is not optimal for gas consumers.[283]

F20 No GPB submitter indicated that it had undertaken an assessment of potential decommissioning liabilities for Generally Accepted Accounting Practices (GAAP) purposes or has plans to do so.

Our assessment

F21 Due to the uncertainty over GPBs' future decommissioning liabilities, and the nature of the potential regulatory issues to be addressed, we do not consider it to be consumers' interests to progress a specific solution for DPP4.

F22 As noted in our Issues paper, it is not clear what the basis for future decommissioning liabilities is, what types of costs might need to be incurred by GPBs, their likely magnitude, or when they are likely to be incurred.

F23 The wider context is also unclear, including the relevance of decommissioning costs to providing the regulated service, which parties' economic interests will be directly or indirectly affected by the eventual retirement/repurposing of networks, how GPBs propose to manage decommissioning (and the associated risks) commercially, and the relevance of other regulatory/reporting regimes and the public policy environment.

F24 While there is benefit in considering this issue in advance of actual decommissioning costs being incurred, at this stage we consider that we lack critical information needed to understand and assess the problem and possible regulatory responses. We did not receive any material new information about the nature of the problem or regulatory implications in submissions on our Issues paper (including GPBs' GAAP treatment).

[280] Firstgas, Powerco & Vector "Letter to the Commerce Commission – Response to Gas DPP4 Issues paper" (24 July 2025), pp. 2, 5-6.
[281] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 16.
[282] Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 9.
[283] MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 36. See also: Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 1.

F25 GPB submitters have indicated that the Gas Infrastructure Future Working Group is working on a desktop study to cost future decommissioning liabilities for GPBs.[284] We understand this is the first study of what future decommissioning for gas networks may involve. The study could be a useful basis for future discussion and engagement with stakeholders, especially if it were to clarify the basis for potential costs and the relevant industry circumstances relating to decommissioning.

F26 We may consider the treatment as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest) or as part of DPP5, when further information and greater clarity for the gas sector may have emerged

Regulatory treatment of non-depreciable easements

F27 Firstgas requested that we review the status of non-fixed life easements as non-depreciable assets in the GDB and GTB IMs as part of the DPP4 reset, and that changing the IM treatment for DPPs is necessary to better reflect easements' economic life.[285]

F28 Our view is that the information provided does not establish an urgent or compelling reason to undertake an out-of-cycle review of the GDB and GTB IMs treatment of easements (or other non-depreciable land assets) ahead of DPP4.

F28.1 In our Issues paper we acknowledged that expectations may have changed about the duration of benefits provided by land assets such as easements (and therefore their depreciation status) due to the wind-down of gas networks.[286]

F28.2 Data we obtained from GPBs for DY 2023 and 2024 indicated that Firstgas Transmission has the largest value of non-depreciable land assets, but information about the nature and value of easements was not available.

F28.3 Our preliminary view in the Issues paper, based on some simple assumptions and calculations, was that a change in regulatory treatment would not be material for allowable revenues, or to incentives faced by GPBs, for DPP4.[287]

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[284] Firstgas, Powerco & Vector "Letter to the Commerce Commission – Response to Gas DPP4 Issues paper" (24 July 2025), p. 2.
[285] Firstgas "Submission on the Gas DPP4 Open Letter" (13 March 2025), p. 3. See also Firstgas, Powerco & Vector "Joint submission on Gas DPP4 Open Letter" (13 March 2025), p. 4. The existing treatment is specified in *Gas Transmission Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 36* and *Gas Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 37*, clause 1.1.4, definition of "fixed life easement"; clause 2.2.5(3); clause 5.3.7(3).
[286] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), para E37.
[287] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), para E39-E40. We also considered that deferring the review until after the DPP4 reset would not likely have a material effect on future building block revenues.

F28.4 In submissions on our Issues paper, Fonterra, Methanex and MGUG supported not progressing this issue for DPP4.[288] Powerco supported no further action being taken in respect of gas distribution networks for DPP4.[289]

F28.5 In its cross-submission, Firstgas stated that easements for its transmission business "represent a significant value" and that delaying depreciation of easements shifts capital costs to future consumers which is not desirable.[290]

F28.6 No other information about the nature or value of easements in GPBs' RABs was provided by Firstgas or any other submitter.

F29 In the absence of information establishing the likely materiality of this issue for DPP4, or any other urgent or compelling reason to initiate an IM amendment consultation process ahead of the DPP4 reset, we are deferring the review of the treatment of non-depreciable easements to the next Part 4 IM review.

F30 We note that any change to the IM treatment of easements for DPP purposes would also likely require consideration of changes to the IMs for ID and CPPs. There may also be implications for the other sectors we regulate. Considering the matter as part of the next Part 4 IM review would allow us to comprehensively address these matters.

Cross-sector solution for addressing the impact of declining demand for gas pipeline services

F31 Greymouth Gas submitted that it had identified a conceptual solution for dealing with the impact of declining supply and demand for GPBs and gas consumers. Broadly, the concept involves revaluing GPB RABs and shifting the cost recovery of the revalued portion to consumers of electricity lines services. Greymouth Gas suggested that we evaluate the proposal and engage with stakeholders as part of the DPP4 reset.[291]

F32 In relation to Greymouth Gas's proposal, MGUG submitted that we should pause our current approach to setting DPP4 and "revise [our] views on workable solutions that might productively address all stakeholder concerns."[292]

F33 Vector submitted that the "proposal would be outside the remit of the Commission to implement, however, it provides an example of the need for continued engagement between the Commission and wider government".[293]

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[288] Fonterra "Submission on Gas DPP4 Issues paper" (24 July 2025), pp. 1-2; Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), pp. 4, 9; MGUG "Submission on Gas DPP4 Issues paper" (28 July 2025), p. 7.
[289] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), p. 11.
[290] Firstgas "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), pp. 29-31.
[291] Greymouth Gas "Submission on Gas DPP4 Issues paper" (27 July 2025); Greymouth Gas "Cross-submission on Gas DPP4 Issues paper" (13 August 2025).
[292] MGUG "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 6. See also pp. 2, 6-7.
[293] Vector "Cross-submission on Gas DPP4 Issues paper" (14 August 2025), p. 19.

F34 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 its cross-submission, it is best considered as part of wider government policy processes.

Attachment G Other inputs into the Financial model

Purpose of this attachment

G1 The purpose of this attachment is to describe the inputs to the financial model we must include in addition to our forecasts of opex and capex discussed in other attachments, including WACC, CPI, and forecasts of disposals and other regulated income.

High level approach

G2 Our approach has been to largely repeat the forecasting methods used in DPP3 with adjustments to shorten the time frame used to calculate historical averages to better capture changes in the gas industry. We also checked that inputs remain consistent with the current IMs. We explain below where we have taken an approach that differs from or is not explicitly set out in the IMs.

G3 Submissions on the DPP4 Issues paper did not include any submissions directly relevant to the forecasting methods discussed in this attachment.

Cost of capital estimate

G4 We set the WACC separate to our DPP reset decisions. The final WACC that will apply for DPP4 will be published in a separate determination no later than 1 April 2026.

G5 For the purposes of our draft decision, we have used the parameters for estimate of WACC from the latest GPB ID WACC determination (calculated as at 1 October 2025) and adjusted the term to reflect our draft decision on the length of the regulatory period (being 5 years).[294]

G6 We set out the parameters we used to calculate the estimate of the WACC for the purposes of our draft decisions below.

[294] Commerce Commission "Gas DPP4 Reset 2026 – Five-year regulatory period – Draft decision reasons paper" (26 June 2025).

Table G1 Parameters for estimate of WACC

Parameter	Estimate of WACC
Risk-free rate	3.79%
Average debt premium	1.21%
Leverage	41%
Asset beta	0.41
Equity beta	0.69
Tax adjusted market risk premium	7.0%
Average corporate tax rate	28%
Average investor tax rate	28%
Debt issuance costs	0.20%
Cost of debt	5.20%
Cost of equity	7.56%
Standard error of midpoint WACC estimate	0.0112
Mid-point vanilla WACC	6.59%
Mid-point post-tax WACC	5.99%

Consumer Price Index forecasts

G7 The revenue path is determined on a nominal basis (consistent with the CPI-X DPP/CPP regime outlined in Subpart 6 of the Act). When using a BBAR/MAR model to determine starting prices, we require a forecast of CPI to project annual revenues for each year of the DPP3 period. Because the asset valuation IM requires the RAB to be revalued at the rate change of CPI, we also require a forecast of CPI to determine BBAR.

G8 The approach we must use is determined by the IMs. For both the rate of change of forecast CPI for RAB revaluations and the rate of change for the price path calculation, the IMs require us to base our CPI forecasts on the RBNZ forecasts of inflation issued as part of its Monetary Policy Statement immediately prior to the determination of the WACC for the DPP.

G9 This information will not be available until after the draft decision has been issued. The results of our approach for the draft decision, which is based on the latest available information, are set out in the table below.

Table G2 Forecasts of CPI

Pricing year ending in calendar year	2027	2028	2029	2030	2031
Revaluation rate, June year-end	2.00%	2.00%	2.00%	2.00%	2.00%
Revaluation rate, September year-end	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation rate, lagged, September year-end	2.67%	2.17%	2.00%	2.00%	2.00%
Inflation rate, not lagged, September year-end	2.07%	2.00%	2.00%	2.00%	2.00%

Forecasts of disposed assets

G10 A disposed asset is an asset that is or is forecast to be sold or transferred, but is not a lost asset.[295, 296] We are required to forecast disposed assets because disposed assets are removed from the RAB when rolling forward the RAB value.

G11 To reach our draft decision, the forecast value of disposed assets in each year of the regulatory period has been forecast in real terms as equal to the historical average real value of disposals (derived from ID actuals). The real forecast time series has then been converted to a nominal time series by adjusting for forecast CPI changes. These results are set out in the table below.

Table G3 Forecasts of disposed assets ($000)

Supplier	2027	2028	2029	2030	2031
Firstgas Transmission	398.4	406.3	414.5	422.8	431.2
Firstgas Distribution	0.9	1.0	1.0	1.0	1.0
GasNet	-	-	-	-	-
Powerco	288.2	293.9	299.8	305.8	311.9
Vector	490.2	500.0	510.0	520.2	530.6

G12 The treatment of gains or losses on disposals as other regulated income is noted in the next section.

[295] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, clause 1.1.4(2).
[296] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 1.1.4(2).

Forecasts of other regulated income for GDBs

G13 Other regulated income is defined in the IMs, and is income associated with the supply of gas, including gains or losses on disposed assets but excluding:[297, 298]

G13.1 income through prices;

G13.2 investment related income;

G13.3 capital contributions; and

G13.4 vested assets.

G14 To forecast the value of other regulated income for our draft decision, we first calculate the historical average real values of gain or loss on disposal as a ratio, subject to a maximum loss cap of 100%. The forecast for other regulated income is then derived by summing the calculated gain or loss with GDB's forecast regulated income. The resulting values are set out in the table below.

Table G4 Forecasts of other regulated income ($000)

Supplier	2027	2028	2029	2030	2031
Firstgas Distribution	471.4	480.8	490.4	500.2	510.2
GasNet	61.9	63.1	64.4	65.7	67.0
Powerco	1,809.4	1,845.6	1,882.5	1,920.1	1,958.5
Vector	-76.6	-78.2	-79.7	-81.3	-82.9

Forecasts of other building blocks cost inputs

G15 In our calculations of the building blocks, there are some building blocks where we have relied on actual ID data as the base for our calculations before making necessary adjustments to reflect GPBs' forecasts, our policy decisions and timing considerations. Some of these base values include the RAB, depreciation, other regulated income and other related components.

G16 Where we have used actual ID data, our draft decision is to use 2024 actual ID values (either as the basis for our own calculations or directly as an input) as this represents the most up-to-date representation of expected profitability.

G17 For our final decision, we are intending to update these values to use 2025 actual ID values.

[297] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, clause 1.1.4(2).
[298] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 1.1.4(2).

Attachment H Framework for setting the default price-quality path

Purpose of this framework

H1 This attachment describes the decision-making framework we will apply in resetting the default price-quality paths (**DPPs**) for gas pipeline services.

H2 This is a conceptual framework to guide and explain our decision-making, without mechanically determining our decision-making. We consider this strikes the right balance between prescription and flexibility in light of potential unforeseeable circumstances that may arise over time.

H3 This framework was adapted from the decision-making framework chapter in our gas DPP3 decisions published in May 2021.299 This attachment is substantively similar to that framework, with minor adjustments. Accordingly, many interested parties will already be familiar with the substance of this framework.

H4 To explain this framework, we discuss:

H4.1 the requirements for setting DPPs under Part 4 of the Commerce Act 1986 (**the Act**);

H4.2 the overarching objectives in the Act that are relevant when setting a DPP;

H4.3 the relevant Gas Input Methodologies (**IMs**); and

H4.4 our framework for making DPP reset decisions, which includes the key economic principles of Part 4 regulation.

H5 This framework is a draft. After considering stakeholder views, the final version of this framework is intended to apply for the gas DPP4 reset.

Requirements for setting Default Price-Quality Paths under Part 4 of the Commerce Act 1986

H6 Under Part 4, gas pipeline businesses (**GPBs**) are subject to two forms of regulation in respect of their supply of gas pipeline services:

H6.1 our information disclosure (**ID**) regulation, under which GPBs are required to publicly disclose information relevant to their performance;[300] and

H6.2 default/customised price-quality regulation, under which price-quality paths set the maximum prices or revenues that GPBs can charge. They also set standards for the quality of the services that each GPB must meet.[301] This

[299] Commerce Commission *Default price-quality paths for gas pipeline businesses from 1 October 2022: Final Reasons Paper* (31 May 2022), ch 2. Available on our website.

[300] Commerce Act, ss 52B and 55C.

[301] Commerce Act, ss 52B, 53M and 55D.

ensures that GPBs do not have incentives to reduce quality to maximise profits under their price-quality paths.

H7 When we reset a DPP, Part 4 specifies several requirements we must follow:

H7.1 the regulatory rules and processes, referred to as Input Methodologies, which we are required to apply when determining the prices and quality standards applying to the supply of gas pipeline services;[302]

H7.2 what must be specified in the DPP determinations;[303]

H7.3 the content and timing of DPPs;[304] and

H7.4 requirements when resetting DPPs.[305]

H8 We must consider the Part 4 purpose and what DPP regulation is intended to achieve when making our decisions. We discuss these objectives and how we are required to use them to set DPPs in the next section of this attachment.

How we apply Part 4 of the Commerce Act when setting a Default Price-Quality Path

Purpose of Part 4

H9 Part 4 provides for the regulation of the price and quality of goods or services in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[306]

H10 Section 52A of the Act sets out the purpose of Part 4 regulation in respect of the regulated goods or services:

> 52A Purpose of Part
>
> (1) The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in s 52A by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—
>
> (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>
> (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
>
> (c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
>
> (d) are limited in their ability to extract excessive profits.

302 Commerce Act, s 52S(b)(ii).
303 Commerce Act, s 53O.
304 Commerce Act, s 53M.
305 Commerce Act, s 53P.
306 Commerce Act, s 52.

H11 Our decisions must therefore promote the long-term benefit of consumers of gas pipeline services. Section 52A guides us that this is to be achieved by promoting four outcomes that are considered consistent with those of competitive markets.

H12 As defined in the Act, a consumer means “a person that consumes or acquires regulated goods or services”.[307] This includes both the direct acquirers of the gas pipelines services and those persons that indirectly consume those services via the purchase of natural gas.

H13 In practice, when setting a DPP, it is important to note:

H13.1 we do not focus on replicating all the potential outcomes or mechanisms of workably competitive markets, but on promoting the s 52A outcomes;

H13.2 none of the objectives listed in s 52A(1)(a) to (d) are paramount, and they are neither separate nor distinct from each other or s 52A(1) as a whole. Rather, we must exercise judgement in balancing the outcomes in s 52A(1)(a) to (d);[308] and

H13.3 when exercising our judgement, we are guided by what best promotes the long-term benefit of consumers of gas pipeline services.[309]

H14 In certain instances, our ability to exercise judgement will be constrained, because we must make our decisions according to specific legal requirements. For example, we must apply:

H14.1 the Gas IMs, which promote the outcomes in s 52A and certainty for suppliers and consumers in relation to the rules, requirements, and processes that apply to the regulation of gas pipeline services; and

H14.2 the mandatory requirements in the Act. For example, s 53M(4) provides that a regulatory period must be five years, while s 53M(5) provides that we may set a shorter period if we consider that it would better meet the purposes of Part 4, but the term may not be less than four years.

Purpose of default/customised price-quality regulation

H15 Section 53K of the Act sets out the purpose of default/customised price-quality regulation:

> The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

H16 We have taken this purpose to mean that:

[307] Commerce Act, s 52C.

[308] *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289 at [684].

[309] *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289 at [165], [222], [684], [686] and [761].

H16.1 DPPs are to be set in a relatively low-cost way, and are not intended to meet all the circumstances that a GPB may face; and

H16.2 customised price-quality paths (**CPPs**) are intended to be tailored to meet the particular circumstances of an individual GPB.

H17 To meet the relatively low-cost purpose of DPP regulation, we must take into account the efficiency, complexity, and costs of the DPP regime as a whole when resetting the DPP. What this means in practice will vary over time and between sectors.

H18 We have developed a combination of low-cost principles, including applying the same or substantially similar treatment to all suppliers on a DPP where this is workable. These principles include:

H18.1 if we are satisfied that using historical information provides a useful proxy for forecast conditions, setting starting prices and quality standards or incentives with reference to historical levels of expenditure and performance;[310]

H18.2 where possible, using existing information disclosed under ID regulation, including suppliers' own asset management plan (**AMP**) forecasts; and

H18.3 limiting the circumstances in which we will reopen or amend a DPP during the regulatory period.

H19 Our application of the low-cost principles is subject to our specific obligations under the IMs and the Act.

Input methodologies

H20 To make the Gas DPP decisions, we must apply the following key Gas IMs:[311]

H20.1 Specification of Price;

H20.2 Cost Allocation;

H20.3 Asset Valuation;

H20.4 Treatment of Taxation.

H21 We must also apply the Cost of Capital IM when we estimate the weighted average cost of capital (**WACC**) that will apply to the DPP regulatory period. We are required to estimate the WACC no later than six months before the start of a regulatory period. We do this as part of a separate process to the DPP reset.

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[310] In periods of significant uncertainty, we recognise that historical information could be an unreliable source of information for the purpose of forecasting certain inputs.

[311] These IMs are set out in the Gas Distribution Services Input Methodologies Determination 2012 (as amended) and the Gas Transmission Services Input Methodologies Determination 2012 (as amended). The IMs can be accessed on our website.

Interaction of climate change policy with the Section 52A purpose

H22 New Zealand is targeting zero greenhouse gases (excluding biogenic methane for which there are separate provisions)[312] on a net accounting emissions basis by 2050 (**2050 target**), as set out in s 5Q of the Climate Change Response Act 2002 (**CCRA**).

H23 Section 5ZN of the CCRA provides:

> If they think fit, a person or body may, in exercising or performing a public function, power, or duty conferred on that person or body by or under law, take into account—
>
> (a) the 2050 target; or
>
> (b) an emissions budget; or
>
> (c) an emissions reduction plan.

H24 The purpose of s 5ZN is to allow the 2050 target and emissions budgets to influence broader government decision making where they are relevant. Parliament left it to decision-makers (acting reasonably) to determine whether and how to take climate change mitigation into account.

H25 We are required to exercise our powers within the scope of our legislative framework, and to make decisions to promote the Part 4 purpose contained in s 52A of the Act. Section 5ZN allows us to take those considerations—the 2050 target, emissions budget, and emissions reduction plan (**ERP**)[313]—into account in the context of fulfilling our statutory purpose, which is to promote the long-term benefit of consumers of gas pipeline services by promoting outcomes consistent with those in workably competitive markets.

H26 However, we cannot have regard to the factors in s 5ZN where doing so would detract from the Part 4 purpose.

H27 Matters that arise from climate change policy might also be relevant to our Gas DPP decisions in the ordinary course outside of the ambit of s 5ZN. If climate change legislation imposed obligations on regulated businesses, and we considered this to be relevant to our decisions or part of the relevant factual context, then we would take this into account in setting the DPP based on ordinary administrative law principles.

Our role to consider or support a transition to alternative gases is limited

H28 Under Part 4 of the Commerce Act, we regulate gas pipeline services. That is, the conveyance of natural gas by pipeline.

[312] In October 2025, the government announced that it will target biogenic methane levels of 14-24 per cent below 2017 levels by 2050. This announcement is subject to Cabinet approval. See website.
[313] Ministry for the Environment *Our journey towards net zero: New Zealand's second emissions reduction plan 2026-2030* (2024).

H29 The term natural gas is not defined in the Commerce Act, which may give rise to uncertainty about whether the conveyance of alternative gases or gas blends falls within the regulated service, for the purpose of regulation under Part 4.

H30 Having considered this issue, we remain consistent in our view that blends of biogas or hydrogen with natural gas could be considered 'natural gas' and can be included in the definition of gas pipeline services where:

H30.1 natural gas is the most significant component of the gas or blend; and

H30.2 conveying the gas or blend does not require a pipeline or appliance conversion.

H31 Unless the above criteria are met, our view is that conveying alternative gases by pipeline cannot be considered a gas pipeline service for the purpose of Part 4.

H32 In line with our statutory purpose, our regulation remains focused on promoting the long-term benefit of consumers of gas pipeline services. That is, consumers in the market for the conveyance of natural gas. Accordingly, our regulatory role does not extend to promoting or facilitating the conveyance of alternative gases or a transition away from natural gas, except where doing so does not detract from the long-term benefit of consumers of gas pipeline services.

H33 Where changing circumstances suggest that regulation should be extended to new goods or services, the Commerce Act contemplates that this should be considered and implemented through the legislation.

H34 At the date of this draft decision, we note that the Minister for Energy has signalled potential amendments to the Commerce Act to clarify the definition of natural gas and, therefore, the scope of the regulated service.[314]

Our framework for making decisions on Gas DPP resets

H35 We intend to apply a consistent decision-making framework to Gas DPP resets, except where we consider making changes would:

H35.1 better promote the purpose of Part 4;[315]

H35.2 better promote the purpose of DPP regulation;[316] or

H35.3 reduce unnecessary complexity and compliance costs.

H36 We consider the Part 4 purpose to be the most important consideration for our decisions. Therefore, we will not make a change on the basis of the other criteria in paragraph H35 where we consider that doing so would detract from that purpose.

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314 Hon Simon Watts, Minister for Energy "Speech to the Biogas Bridge Forum" (Wellington, 23 July 2025).

315 Commerce Act, s 52A.

316 Commerce Act, s 53K.

H37 We have adapted this framework from previous regulatory projects, including IM Reviews and Electricity and Gas Reset decisions.[317] We consider maintaining our approach helps ensure regulatory certainty and consistency with the low-cost purpose of the DPP.

A "building blocks" approach to price-quality regulation

H38 Our price-quality (**PQ**) regulation under Part 4 is based on a building blocks method (**BBM**).

H39 BBM creates financial incentives which align regulated suppliers' interests with those of their customers in reducing costs and becoming more efficient. This alignment of incentives is achieved over regulatory control periods, where the maximum revenues (or prices) for delivering the regulated services over the regulatory control period are specified up front.

H40 Setting the maximum revenues (or prices) in this way provides an ex ante opportunity for the regulated provider to earn its allowed return. The allowed return under a BBM approach is the best estimate of the return that an efficient firm has an ex ante opportunity to earn in a workably competitive market (sometimes referred to as a 'normal return'). Where regulated suppliers outperform their allowed returns by becoming more efficient they enjoy the benefit of these efficiencies (in the form of higher profits) with the efficiencies shared with consumers at the next reset in the form of reduced revenues (or prices).

H41 BBM is also used as part of ID regulation to underpin the assessment of returns which helps us and other interested parties in assessing whether the outcomes in s 52A are being met.

H42 We have developed a decision-making framework and set of economic principles over time to support our decision-making under Part 4 when we determine the values of the specific building blocks under the IMs.

H43 These have been consulted on and used as part of prior processes and help provide consistency and transparency in our decisions.

H44 However, we recognise that issues may arise over time and that we need to be open to modifying or changing our approaches where this would better promote the purpose of Part 4.

H45 While we recognise the uncertainty in the gas sector and that demand for piped natural gas in New Zealand is likely to decline over time, we still consider that our existing approaches to PQ regulation described above would likely best give effect to the purpose of Part 4 in the current context.

[317] For example, see Commerce Commission *Default price-quality paths for gas pipeline businesses from 1 October 2022: Final Reasons Paper* (31 May 2022), ch 2. Available on our website.

Economic principles

H46 We have three key and longstanding economic principles that we have regard to in setting DPPs under Part 4. We consider that these are useful analytical principles that can help us reach decisions that promote the Part 4 purpose. They can also help promote regulatory predictability by signalling to stakeholders how we are likely to approach relevant decisions. However, if the principles cease to be consistent with the Part 4 purpose in a specific situation, we will not continue to apply them.

H47 The three principles are:

H47.1 *Real financial capital maintenance (**FCM**)*: we provide regulated suppliers with the ex ante expectation of earning their risk-adjusted cost of capital (a 'normal return'). This provides regulated suppliers with the opportunity to maintain their financial capital in real terms over timeframes longer than a single regulatory period. However, price-quality regulation does not guarantee a normal return over the lifetime of a regulated supplier's assets.

H47.2 *Allocation of risk*: ideally, we allocate particular risks to regulated suppliers or consumers depending on who is best placed to manage the risk. In order to determine the regulatory settings in price-quality regulation that will give effect to the FCM principle, we consider the allocation of risk. We aim to allocate risks to the party best placed to manage them. Managing risks includes:

H47.2.1 actions to influence the probability of occurrence where possible;

H47.2.2 actions to mitigate the costs of occurrence; and

H47.2.3 the ability to absorb the impact where it cannot be mitigated.

H47.3 Regulated suppliers have various risk management tools at their disposal, including insurance, investment in network strengthening/resilience, hedging, contracting arrangements and delaying certain decisions eg, when to make large investments. Once the risks are allocated between regulated suppliers and consumers, we compensate regulated suppliers and consumers accordingly through the price-quality path we set.

H47.4 *Asymmetric consequences of over- and under- investment*: we apply FCM recognising that usually there are asymmetric consequences to consumers of regulated energy services, over the long-term, of under-investment.

H48 We elaborated on each of these principles and how they should be applied in the context of price-quality regulation in our 2023 IM Review framework paper.[318]

[318] Commerce Commission *Part 4 Input Methodologies Review 2023* Framework paper (13 October 2022) available on our website.

Glossary

Term or abbreviation	Description
2023 IM review	Second statutory input methodologies review completed in December 2023
2050 target	New Zealand's target to achieve net zero emissions of greenhouse gases by 2050
AER	Australian Energy Regulator
ALENZ	Aluminium Extruders of New Zealand
AMP	Asset management plan
ARR	Asset replacement and renewal
BBM	Building blocks model
BBAR	Building blocks allowable revenue
BST modelling	Base-step-trend opex modelling
CAGR	Compounded annual growth rate
CAIDI	Customer average interruption duration index
Capex	Capital expenditure
CC	Consumer connection
CCC	Climate Change Commission
CCUS	Carbon capture, utilisation and storage
CGPI	Capital goods price index
Commerce Act	Commerce Act 1986
Commission	The Commerce Commission/*Te Komihana Tauhokohoko*
CPI	Consumer price index
CPP	Customised price-quality path
CPRG	Constant price revenue growth
DPP	Default price-quality path
DPP1	Default price-quality path for the first regulatory period (1 October 2013 – 30 September 2017)
DPP2	Default price-quality path for the second regulatory period (1 October 2017 – 30 September 2022)
DPP3	Default price-quality path for the third regulatory period (1 October 2022 to 30 September 2026)
DPP4	Default price-quality path for the fourth regulatory period (the regulatory period commencing 1 October 2026)
DY20xx	Disclosure year 20xx
EDB	Non-exempt regulated electricity distribution business
EDB DPP4	EDB default price-quality path for the fourth regulatory period (1 April 2025 to 31 March 2030)
EECA	Energy Efficiency and Conservation Authority
EGWW	Electricity, gas, water and waste sector
ERP	New Zealand's first emissions reduction plan 2022-25
ERP2	New Zealand's second emissions reduction plan 2026-30
FCM	Financial capital maintenance
Firstgas	First Gas Limited, a natural gas transmission and distribution business
Fonterra	Fonterra Co-operative Group Limited
GAAP	Generally accepted accounting practice
Gas Act	Gas Act 1992
Gas IMs	Input Methodologies for gas pipeline services: Gas Distribution Services Input Methodologies Determination 2012 (as amended) and the Gas Transmission Services Input Methodologies Determination 2012 (as amended).
GasNet	GasNet Limited, a regulated natural gas distribution business
GDB	Regulated natural gas distribution business
GIC	Gas Industry Company Limited

GIFWG	Gas Infrastructure Future Working Group
Government	New Zealand Government/ *Te Kāwanatanga o Aotearoa*
GPB	Gas pipeline business, being either a GDB or GTB
Greymouth Gas	Greymouth Gas New Zealand Limited
GTAC	Gas transmission access code
GTB	Regulated natural gas transmission business
GTP	Gas transition plan
ICP	Installation control point
ICT	Information and communication technology
ID	Information Disclosure
IMs	Input Methodologies
IM Review	Statutory Input Methodologies Review
IRIS	Incremental rolling incentive scheme
LCI	Labour cost index
MAR	Maximum allowable revenue
MBIE	The Ministry of Business, Innovation and Employment/*Hīkina Whakatutuki*
MGUG	Major Gas Users' Group
NN	Non-network
NPV	Net present value
NZIER	New Zealand Institute of Economic Research
OCR	Official cash rate
Ofgem	The Office of Gas and Electricity Markets
Opex	Operating expenditure
Part 4	Part 4 of the Commerce Act 1986
Powerco	Powerco Limited, a regulated natural gas distribution business
PPI	Producer price index
PQ	Price Quality
RAB	Regulatory asset base
RBNZ	Reserve Bank of New Zealand/*Te Pūtea Matua*
RFI	Request for information between the Commission and regulated GPBs, which may contain confidential information
RNG	Renewable natural gas
RSE	Reliability, safety and environment
RTE	Response time to emergencies
SaaS	Software as a service
the Act	Commerce Act 1986
TAMRP	Tax-adjusted market risk premium
UDL	Utilities Disputes Limited/*Tautohetohe Whaipainga*
Vector	Vector limited, a regulated natural gas distribution business
WACC	Weighted average cost of capital
WAPC	Weighted average price cap
WIP	Work in progress
WorkSafe	WorkSafe New Zealand/*Mahi Haumaru Aotearoa*
x-factor	The rate of change in prices. If prices are increasing, then the value of x will be negative when applying a CPI-X approach