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Dear Matthew,

Gas DPP4 2026: Firstgas views in response to draft decision

Thank you for the opportunity to provide our views on the Commerce Commission's (Commission) draft decision on the fourth Default Price-Quality Path (DPP4) reset for natural gas pipeline services. This Firstgas submission is made on behalf of our gas transmission business (GTB) and gas distribution business (GDB).

As a member of the Gas Infrastructure Futures Working Group (GIFWG), we have reviewed its submission and support the key messages it presents.

This document contains some confidential information. We have provided two copies to the Commission, with the public version redacting the information that is commercially sensitive. Please consult us if the Commission receives a request under the Official Information Act (OIA) for information that is marked confidential. We consider that the Commission has grounds to withhold this information pursuant to section 9 of the OIA.

Executive Summary

This submission provides Firstgas' views on the draft Default Price-quality Path reset decision for the period 1 October 2026 – 30 September 2031 (DPP4). Overall, we agree with the focus that the draft decision places on regulatory predictability and stability, particularly in continuing to accelerate depreciation to reflect uncertain future demand for gas pipeline services.

This submission identifies improvements to the draft decision that we consider better reflect ongoing changes in New Zealand's gas industry.

Overarching themes discussed in this submission

The points made in this submission fall into three broad themes that we believe the Commission should apply to ensure that the DPP4 reset provides a coherent, consistent basis for regulating gas networks over the coming five-year period. These are set out in the following table.

Theme and main points in this submission	Section
The energy transition is changing what consumers need from gas networks:	
• The range of future scenarios facing gas networks is wide but all scenarios see continued reductions in gas use	2
• Networks need to build capability in asset planning and forecasting to inform future decisions under uncertainty	3
• Quality standards (like the major interruption standard) should consider consumer impacts to avoid incentivising networks to provide levels of reliability and resilience that are no longer appropriate	6
Adapting to these changes early will avoid future price shocks for consumers:	
• Continued accelerated depreciation reduces the fixed costs that need to be recovered from future users	2
• Demand for gas pipeline services is expected to decline over the regulatory period (and beyond), limiting future revenue recovery opportunities, increasing the burden on a smaller group of customers	2
• Regulatory depreciation should apply to transmission easements since these assets now have a fixed life	2
• Balancing and fuel gas costs should be incorporated into the calculation of smoothing limits to mitigate price shock	4
• Providing for future network decommissioning costs now is prudent, to ensure the future costs are borne by consumers benefitting from the network	5
Spending now can save money later:	
• Decommissioning uneconomic assets (such as redundant compressors and stations) increases near-term opex but reduces lifetime opex through avoided maintenance	3
• Substituting capex for opex makes sense to avoid investing in solutions that add to the fixed cost base	3
• Selected growth can still provide consumer value and support energy choice but costs should be weighted towards direct beneficiaries to avoid adding to the risk of future price shocks	5

Specific recommendations made in this submission

This submission recommends that the Commission makes the following changes for the final DPP4 reset decision:

Commission's Draft Decision	Our recommendation	Our rationale
The Commission decided to retain its 2050 and 2060 long-term industry wind-down scenarios and their relative one-third and two-thirds respective weightings	The Commission adds an earlier wind-down scenario in 2040. If that is impractical, flipping the weighting of the existing scenarios towards the 2050 scenario would better reflect the balance of plausible outcomes	The Commission undertook to refresh its scenarios for accelerated depreciation at each DPP reset. Industry changes since 2022 (particularly steep reductions in gas production and the gas supply outlook) have been adverse and have increased the risk of gas pipeline asset stranding. Recovering capital faster benefits the consumer through maintaining network viability and ensuring access for consumers who want to use gas
The Commission considers there is no compelling reason for an out-of-cycle review of the treatment of non-fixed life easements	The Commission applies regulatory depreciation to transmission easements since these assets now have a finite life	In line with standard accounting practice and the reality of their economic lives, our transmission easements should be depreciated. It is financially significant for us and future customers will appreciate those charges being spread over a larger customer base that includes DPP4
The Commission's application of accelerated depreciation is unchanged from DPP3	The Commission reduces the life of new assets by both DPP3 and DPP4 accelerated depreciation factors	This would correct the discrepancy between the accelerated depreciation factors applied to new and existing assets, reflecting the cumulative effect of decisions to accelerate depreciation on the assumed life of new assets
	The Commission changes the approach to compliance with accelerated depreciation allowances to remove the impact of inflation on acceleration factors	Any mismatch between actual and forecast CPI will lead to inaccurate revaluation of assets and write-downs not achieving the Commission's intent

Commission's Draft Decision	Our recommendation	Our rationale
The Commission's draft decision does not provide adequate expenditures in DPP4	The Commission increases expenditure allowances to reflect additional step change evidence provided on: • Cyber security • Software-as-a-service (SaaS) • Transmission station and compressor decommissioning • Transmission legal costs for urbanisation	The reasons vary by topic and are provided in Section 3 and various appendices. Broadly: • Higher expenditure is required on cyber security to lower operational risks and improve our capabilities to operate in line with acceptable industry standards for a nationally significant utility. If an allowance is not afforded to be invested in, consumers are being placed at significant risk of facing the material cost associated with a cyber security breach. • For SaaS: An accounting change during DPP3 has shifted capex to opex, Industry best practice requires increased SaaS spend, and technology costs are rising faster than inflation. Our requests are to accommodate for this technical accounting change, and are not a 'double-dip'. • Decommissioning represents prudent, near term expenditure that prevents ongoing and unnecessary lifecycle costs, which would be inefficient costs for consumers to bear. • Higher legal costs to reduce urbanisation encroaching on pipeline corridors is good for gas consumers because it avoids even higher capex.
In a change from previous, the Commission plans to "Set a 'revenue smoothing limit' at 10% above the CPI-X rate of change for the GTB and specify the revenue smoothing limit	The Commission includes the current year's recoverable costs forecast in the calculation of revenue smoothing limit	This will help to avoid the recovery of balancing costs and fuel gas costs being deferred and placed on future consumers

Commission's Draft Decision	Our recommendation	Our rationale
with reference to the sum of forecast net allowable revenue for the current year and forecast recoverable costs for the previous year"[1]		
The Commission considers disconnections, right-sizing (especially service withdrawal) and large-scale decommissioning out of scope from DPP4	The Commission includes a provision in DPP4 for future network decommissioning costs arising in future DPPs (while still progressing disconnection monitoring and right-sizing investigation outside of DPP4)	This is the Commission's last opportunity to have gas consumers in DPP4 make some sort of contribution toward large future costs of decommissioning. Failing to act will ensure the future liability grows and is even more unfairly shared
The Commission considers the current definition of a 'major interruption' to be adequate	The Commission acknowledges the potential for the definition of a 'major interruption' to inadvertently capture minor events and commits to consulting separately on appropriate changes	The definition encompasses potential events much smaller than the Commission intended when it introduced this quality standard. So long as the Commission applies the intended proportionality in its enforcement, then the current situation is manageable. A replacement definition would need careful consideration to not apply the wrong investment incentives for gas transmission.

[1] Gas-DPP4-Draft-decision-reasons-paper-27-November-2025.pdf

1) Introduction

The draft decision to reset the DPP for gas pipeline businesses is the most recent step in a process that began in early 2025 with an open letter to establish key issues. Stakeholder views on those issues were provided in response to a detailed issues paper released in the middle of 2025. This section provides some reflections on the DPP4 reset process and presents the structure of this submission.

General observations on DPP process that has informed draft decision

In our view this DPP4 reset process sets the benchmark for consumer engagement in a DPP reset. Specifically, the decision draws on three initiatives outside of usual written stakeholder submissions:

- Gas Infrastructure Futures Working Group (GIFWG) qualitative research on the views of residential natural gas consumers[2]
- Commerce Commission engagement with 12 large gas users[3]
- Commerce Commission engagement with residential gas consumer advocates.[4]

We believe that this level of consumer engagement should be the norm for resetting DPPs. The benefits from this engagement in informing regulatory decisions, supplier plans, and building consumer understanding and support for the Commission's decisions clearly outweigh the costs involved. While we appreciate that DPPs are designed to be a low-cost regulatory tool and that more consumer engagement is incorporated into the Customised Price-quality Path (CPP) process, we still believe that this form of direct engagement fits with the DPP regime.

We also appreciated the opportunity to discuss scenario modelling in a workshop forum, where participants heard from a range of stakeholders on their perspectives on the possible futures facing the New Zealand gas industry and gas pipelines specifically.[5] In our view, this forum allowed for deeper engagement on the issues and trade-offs involved, and adds

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[2] *What's fair? Qualitative Research Topline Findings Of The Views Of Residential And Business Natural Gas Customers* available from https://www.comcom.govt.nz/assets/pdf_file/0038/367778/Firstgas2C-PowerCo-26-Vector-Attachment-C-Qualitative-Research-Report-Summary-prepared-by-Pinstriped-Leopard-24-July-2025.pdf
[3] *What Rising Gas Prices Mean For NZ Businesses* available from https://www.comcom.govt.nz/assets/pdf_file/0024/368124/Gas-DPP4-Summary-of-large-gas-user-engagements-August-2025.pdf
[4] *Summary Of Our Kōrero With Residential Gas Consumer Advocates* available from https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Gas-DPP4-Consumer-korero-summary-22-September-2025.pdf
[5] Gas-DPP4-Scenarios-modelling-workshop-slides-15-July-2025.pdf

legitimacy to the Commission's decisions. We encourage the Commission to incorporate workshops into major regulatory decisions on the Input Methodologies and DPP/CPP resets.

Structure of this submission

The remainder of this submission is structured as follows:

- Section 2 discusses the Commission's approach to setting accelerated depreciation allowances and the scenario modelling that informs those allowances
- Section 3 focuses on expenditure allowances and appendices provide further evidence for the step changes requested for our gas transmission and gas distribution businesses
- Section 4 addresses network revenue and pricing issues, including changes to the gas transmission revenue cap and the Commission's approach to setting constant price revenue growth for gas distribution
- Section 5 provides our views on disconnections, network right-sizing and decommissioning – all topics that have been raised throughout the DPP4 reset process
- Section 6 discusses quality standards and information disclosure on quality-related metrics
- Section 7 makes some concluding remarks
- Appendices provide supplementary information on topics discussed in the body of the paper.

2) Asset stranding risk, accelerated depreciation and scenario modelling

The approach to accelerated depreciation for DPP4 in the draft decision builds on the Commission's DPP3 reset decision in 2022, which was tested through the High Court merits review decision in 2024. In this section we highlight some of the issues with this approach and recommend changes to ensure that depreciation allowances reflect the changes that have occurred since 2022.

Changes since 2022 have increased asset stranding risks

The Commission has broadly retained its approach to accelerated depreciation in the draft decision, emphasising the value of regulatory stability. We support this decision and agree that regulatory stability and predictability is valuable for gas consumers and gas pipeline businesses.

That said, we consider that more work could have been completed in the DPP4 reset process to test the plausibility of the two scenarios used to calculate accelerated depreciation. A lot has changed since May 2022 when the Commission decided on the scenarios for DPP3, and yet the continued use of 2050 and 2060 winddown scenarios has not captured these changes.

In our view, the weight of changes since 2022 has clearly increased the risk of asset stranding. The changes include:

- **Sharp declines in gas production and reserves:** production declined for 8 straight quarters through to September 2025 and is predicted to fall below 100 PJ in 2026. At paragraph D86 of the draft decision, the Commission points to supply-side factors that were considered at the DPP3 reset. However, the rate and extent of the decline in gas production has been much faster and deeper than anyone expected back in 2022 – a time when producer forecasts expected supply to increase to more than 200 PJ per year.[6]
- **Significant increases in delivered gas prices, driven by constrained supply and higher retail gas margins (as well as passing through higher network charges):** our submission on the DPP4 issues paper identified that increasing retail gas margins have been reported throughout DPP3, especially for residential consumers. We infer from the evidence that a shortage of gas supply is driving these price increases.

[6] See BCG (2025) "Energy to Grow", Exhibit 32 on page 50: energy-to-grow-full-report.pdf

- **Changes in gas distributor policies and procedures:** including decreases in long-lived asset capital expenditure, initial steps towards network right-sizing, and increasing capital contributions for new connections.
- **Vocal consumer advocates pushing for households to disconnect from gas networks:** based on claims that we have reached a "tipping point" where electricity can replace gas for household uses and both save money and reduce emissions.[7]
- **Promised subsidies for electrification:** Political parties campaigning in the 2023 general election on providing households with financial incentives to replace gas appliances.[8]

The Commission has specifically asked for stakeholder views on the prospect that the closure of the Maui gas field results in Methanex ceasing operations in New Zealand. In our view, this is a plausible scenario because the Maui field is approaching its minimum production rate of 30 TJ/day and Methanex has demonstrated in recent years that it is the main source of flexibility for accommodating gas market changes of this size.

We see the prospect of a Maui/Methanex exit as increasing the need for an earlier return of capital for gas pipelines. Methanex has played an important role in funding gas supply development efforts in New Zealand, and without Methanex underwriting new development it will be more difficult for gas producers to invest. While Methanex is not a major contributor to pipeline revenue (due to its proximity to gas fields), its activities have underpinned gas production in New Zealand and its absence would change the make-up and trajectory of the gas sector.

While we acknowledge that some changes since 2022 weigh against the risk of asset stranding these do not balance out the negative factors described above.

Given recent government announcements on LNG, we have specifically considered how LNG should factor into the Commission's decision-making in Box 1. In our view, the impact of LNG is minor and the balance of changes since 2022 is dominated by low production and reserves. The potential introduction of LNG is akin to an insurance policy: it adds costs but helps ensure gas demand can be met under a wider range of supply-side circumstances.

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[7] See for example Rewiring Aotearoa "Electric Homes" March 2024 Electric Homes Report | Rewiring Aotearoa (page 3).
[8] For example, the Labour Party 2023 manifesto commits to "Establish a new $3,000 rebate for households who electrify and move off gas". See labour_manifesto_2023.pdf (page 10).

Box 1: Impact of LNG on accelerated depreciation and scenario modelling

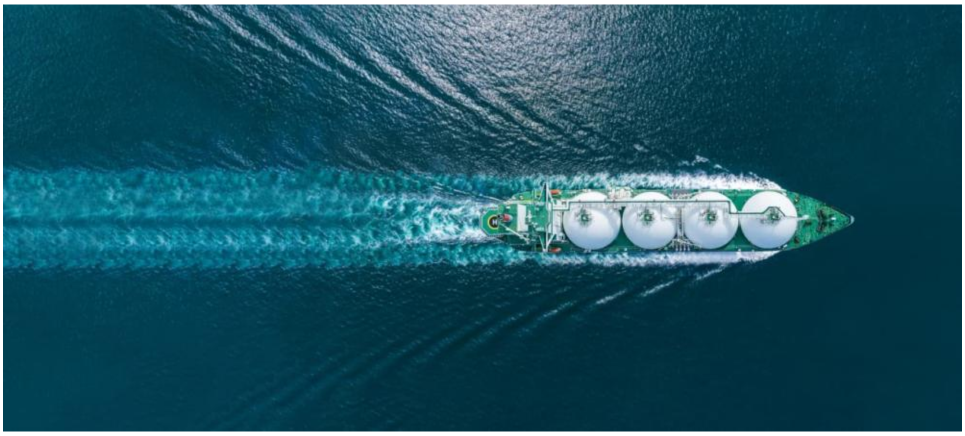
In November 2025, the government began a process to procure an LNG import facility for New Zealand. At the date of this submission, no further government announcements have been made on the procurement process, although we understand the government has indicated a willingness to progress further.

While any government decisions on LNG are uncertain, we believe that even a firm commitment to establish an LNG facility in New Zealand should not impact on the Commission's proposed approach to accelerated depreciation for gas pipelines:

- The LNG import facility considered by the government is explicitly stated to run for a term of 15 years (i.e. to around 2042). While facility extensions are possible, this is much earlier than the Commission's most pessimistic scenario of a 2050 winddown
- Accelerated depreciation addresses the risk of reductions in demand. Concerns about a shortfall in gas supply did not feature at the DPP3 reset, yet the Commission introduced accelerated depreciation based on future demand risks (including those arising from New Zealand's legislated net zero 2050 emissions target).

We consider that the best way to incorporate the prospect of LNG in scenario modelling is to incorporate a much smaller network footprint (due to the higher price of LNG). This has been factored into one of the GIFWG scenarios described below.

Further information on the feasibility of LNG imports to New Zealand is available here: [Gas Strategies - NZ LNG Import Feasibility Assessment]



Reflecting a wider range of plausible outcomes in scenario modelling

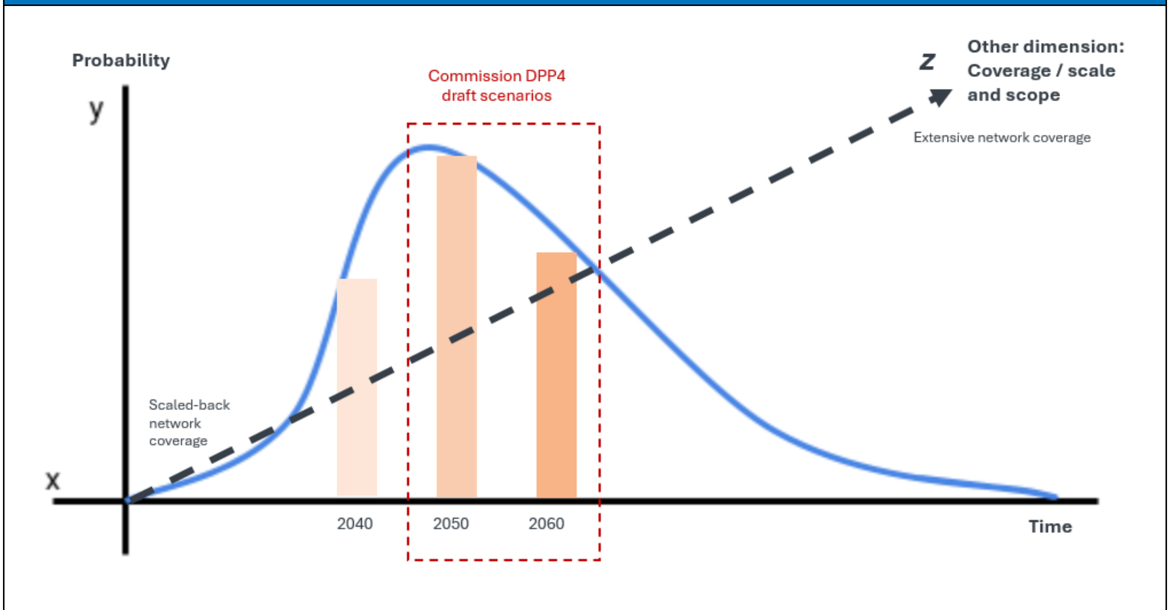
The Gas Infrastructure Futures Working Group (GIFWG) has modelled the outcomes of a broader range of scenarios than considered in the Commission's DPP4 reset modelling. This analysis considers timeframes that are wider than the Commission's 2050/2060 scenarios by incorporating:

- A 2040 supply driven winddown scenario
- A smaller network scenario where pipeline services continue for the foreseeable future across a much smaller footprint (with fewer customers contributing revenue)
- Substitution of domestic natural gas with a combination of higher priced renewable gas and imported LNG.

The GIFWG scenarios make a valuable contribution to the DPP4 reset by testing a wider range of possible outcomes and adding an additional variable to the scenarios: network scale and scope. While the Commission's modelling implies that networks are gradually wound-down before an eventual closure in 2050 or 2060, the GIFWG work explicitly considers how network closures might be sequenced and what impact this has on the viability of providing services to remaining customers.

This is illustrated conceptually in the following graph, showing that while the Commission's DPP4 draft scenarios may represent the most likely outcomes, a shorter 2040 outcome is also plausible – and that there is another dimension on which outcomes will vary (the coverage / scope and scale of networks):

Stylised illustration of GIFWG scenarios



The results of the GIFWG scenario modelling work confirm the direction and broad magnitude of the Commission's draft DPP reset decision. Additional accelerated depreciation is required to provide investors in the gas pipelines with a reasonable expectation of having their capital returned before these scenarios eventuate.

The most relevant findings of the work include:

- Each of the scenarios modelled identifies a shortfall in capital returned to suppliers – ranging between $690 million to $1.1 billion in present value terms. This arises from a combination of unrecovered revenue (insufficient demand given the alternative energy sources available to consumers) and unrecovered RAB at the end of the modelling period.[9]
- Plausible scenarios reduce, but do not eliminate, capital recovery risks. Sensitivity analysis shows that if alternative energy options are more expensive than anticipated then the capital recovery shortfall is between $327 million and $541 million in present value terms.[10]
- Consumer gas bills are expected to rise under all scenarios as network prices rise (with demand reductions) and wholesale gas prices rise (with supply constraints). This may cause future retail gas margins to contract and may encourage consumers to switch to other energy options.

This analysis confirms that the accelerated depreciation factors proposed in the draft decision help to mitigate this stranding risk but do not eliminate the risk. To some extent this can be seen as consistent with the Commission's definition of the principle of Financial Capital Maintenance (FCM), providing an expectation but not a guarantee of normal returns. However, the GIFWG scenarios also suggest that changing modelling parameters to accelerate recovery is warranted. The recommendations made below aim to reduce asset stranding risk arising from these broader scenarios.

Asset stranding risk and depreciation of gas transmission easements

The Input Methodologies define easements as a "right to use but not possess land belonging to another person or a right to prevent certain uses of another person's land". On acquisition, easements either have a fixed life or are considered 'perpetual'. The Input

[9] Firstgas analysis of GIFWG modelling. We sourced from the sum of cells D236 and D241 on 'ROI and cash flow' tab of GIFWG's model (which is not yet public).
[10] Ibid, but instead applying a consumer cost of capital of 10% (rather than 5%) and assuming alternative energy charges are 10% higher.

Methodologies define a fixed-life easement as “an easement that: (a) is of fixed duration; or (b) whilst of indefinite duration, is to be held for a fixed period.”

Our gas transmission business holds easements that allow access to our pipeline and other network assets that sit within private or council land. Most Firstgas easements are currently categorised as ‘other than a fixed life easement’ (non-fixed life or perpetual) under the input methodologies as they do not meet the definition of a fixed life easement. This means there is no contractual or legal ‘end of life’ of the easement and the easements are therefore not depreciated for regulatory purposes.

Theoretically a business can have perpetual easements. However, in practical terms, easements, where tied to assets, only have value while the underlying assets are in service and the business is in operation. Once the underlying assets are decommissioned or the business ceases operation, easements generally have no further use or economic value. For Firstgas transmission, the terms of our easements are limited to the provision of gas transmission services and therefore could not be used for any other purpose.

The current Input Methodologies allow depreciation of fixed-life easements and the DPP determinations allow accelerated depreciation reflecting that the benefits from those easements are limited to the end of their economic life. In contrast, the Input Methodologies treat non-fixed-life, perpetual easements as assets that will benefit the business indefinitely. We noted in our response to the open letter[11] and in our cross-submission on gas DPP4 issues paper[12] that not allowing depreciation of non-fixed-life, perpetual easements implies that the gas network itself is a perpetual asset benefiting from the easements indefinitely. This assumption of a perpetual asset and business is no longer tenable, given supply constraints and declining demand that may lead to significant parts of the network being eventually decommissioned. In their winddown scenarios, the Commission themselves view the network assets being eventually decommissioned.

Non-depreciable easements with no resale value or alternative use means capital invested in these easements is stranded forever and never returned to investors which is an absolute failure of Financial Capital Maintenance (FCM). In Wellington International Airport’s decision[13], the High Court recognised FCM as “central to the Commission’s approach” and endorsed its approach as “non-controversial. The link between asset stranding and

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[11] https://www.comcom.govt.nz/__data/assets/pdf_file/0025/365038/Firstgas-Submission-on-Gas-DPP4-Open-Letter-13-March-2025.pdf P3

[12] https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Firstgas-Cross-submission-on-Gas-DPP4-Issues-paper-14-August-2025.pdf P29

[13] Wellington International Airport Ltd v Commerce Commission [2013] NZHC 3289 [Wellington International Airport] at [256]

maintaining FCM was further reinforced in Major Gas User Group (MGUG)'s decision[14], where the High Court noted:

> *"Financial capital maintenance cannot be sustained if assets are stranded; that is to say, if assets are no longer able to earn enough revenue to enable investors to recoup the balance of their investment."*

While a WACC return is provided, WACC components do not cover asset stranding risk[15]. Depreciation is the mechanism through which capital recovery occurs and excluding these easements from depreciation shifts costs to future consumers. As the likelihood of network decommissioning increases, depreciating easements associated with assets expected to be retired would better align depreciation and cost recovery with the remaining economic life of the network. This approach would provide a more accurate reflection of network economics and ensure a fairer allocation of costs between current and future consumers, particularly for businesses such as Firstgas Transmission where these easements represent a material value.

Accounting treatment

NZ IAS 38 Intangible Assets (paragraph 88) and the PwC Manual of Accounting (paragraph 21.102) set out that management should assess whether an intangible asset's useful life is finite or indefinite. An intangible asset should be regarded as having an indefinitely useful life if, based on all the relevant factors, there is no foreseeable limit to the period over which the assets is expected to generate net cash inflows for the entity.

Furthermore, paragraph 21.106 of the PwC Manual of Accounting states that the useful lives of certain intangible assets are restricted by the period for which contractual or other legal rights are held. The useful life of such assets is the shorter of the periods determined by economic factors and contractual or other legal factors. A supporting example provided in PwC's manual illustrating this concept confirms that if the legal life of a copyright was 50 years, but the economic life is only 30 years (that is, it will only generate economic benefits for 30 years), the entity must amortise the copyright over 30 years. It must then derecognise the copyright after 30 years at the point when no future economic benefits are expected from its use.

Furthermore, the PwC manual confirms that indefinite life is not the same as infinite. For an asset to be considered 'indefinite' in life, management must be committed to continued investment for the long-term to extend the period over which the intangible asset is expected to continue to provide economic benefits.

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[14] Major Gas Users' Group Inc v Commerce Commission [2024] NZHC 959 [Major Gas Users' Group] at [33]
[15] Ibid at [34]

Consistent with accounting standards, in 2023 Firstgas easements were given a fixed life for accounting purposes to reflect the fact that there is a foreseeable limit to the period over which they are expected to generate cash-flows. The easements are only expected to earn cash-flows whilst the network remains operational and given the gas network is now considered to have a finite life, the useful lives of easements have been adjusted and is being amortised accordingly.

Expert opinion

We engaged Deloitte to provide advice on the current regulatory treatment of non-fixed duration easements under the Gas Input Methodologies, and whether this treatment remains appropriate in light of recent developments affecting GPBs.

Deloitte's assessment is that the assumption underpinning the current treatment 'that non-fixed duration easements provide benefits in perpetuity' has been materially weakened. Forecast demand reductions, increased policy uncertainty, and the Commission's own scenario analysis now point to gas networks having a finite economic life, with a heightened risk of partial or full network wind-down over the medium to long term. In these circumstances, easements that are operationally and economically inseparable from the gas network cannot reasonably be expected to retain indefinite economic value where the underlying network no longer operates.

The Deloitte report further notes that the Commission's decisions in DPP3 recognised these risks by shortening regulatory asset lives to better reflect expected economic lives and mitigate stranding risk. Hence, the continued treatment of non-fixed duration easements as non-depreciable is increasingly difficult to reconcile with this approach. Where the Commission has accepted that core transmission assets have finite economic lives, treating associated easements as having indefinite lives creates an internal inconsistency and risks leaving unrecovered asset values.

Accounting standards provide a relevant and well-established analogue. Intangible assets assessed as having indefinite lives must be reassessed each reporting period, and reclassified as finite-lived where circumstances no longer support an indefinite life assessment. The evolving risk profile of gas networks suggests that the prior indefinite-life assessment for these easements is no longer robust, supporting regulatory consideration of a finite-life treatment.

From a regulatory perspective, maintaining the current treatment raises concerns in relation to ex-ante Financial Capital Maintenance (FCM). Deferring consideration of this issue until a future IM review increases the expectation of under-recovery as the customer base declines, potentially undermining investment incentives in a manner inconsistent with Part 4 objectives.

The report further notes that the consumer price impacts of allowing depreciation of non-fixed duration easements are expected to be modest. Deloitte's illustrative analysis indicates that enabling depreciation would result in relatively small increases in transmission charges, particularly if implemented earlier, while reducing the risk of larger price shocks in later periods when demand is lower. Earlier recognition therefore aligns with the Commission's stated preference for smoothing recovery and managing intergenerational impacts on consumers.

In summary, the report notes that:

- Non-fixed duration easements now have a finite economic life in the context of a declining gas sector.
- Allowing depreciation would improve consistency with DPP3 decisions and the Commission's own treatment of stranding risk.
- Earlier action would better support ex-ante FCM, mitigate under-recovery risk, and smooth consumer impacts.
- The scale of consumer impacts does not appear to provide a compelling reason to defer consideration to a future IM review.

We, therefore, consider it is timely for the Commission to actively consider the treatment of non-fixed duration easements in the context of the DPP4 reset, rather than deferring the issue on the basis of materiality.

The report is provided in Appendix E.

Recommendations on fixed life easement definition

We recommend that an expanded definition of fixed life easements is adopted that explicitly recognises the finite life (period) over which these easements are economically useable. We propose the definition is changed to, "an easement that: (a) is of fixed duration; or (b) whilst of indefinite duration; (i) is to be held for a fixed period, *(ii) is useable for a fixed period*."

Practically, non-fixed life easements are not infinitely usable. Once the business ceases operations or underlying asset reaches the end of life and is no longer in use, the associated easements may have no economic value. The proposed definition would allow such easements to be depreciated consistently with the asset/s located on the land and business operations.

Modelling and implementation issues

The modelling of the accelerated depreciation factor for DPP4 creates a divergence between the lives for existing and new assets that was not present in DPP3 because it was the first regulatory period in which accelerated depreciation was applied.

The modelling of accelerated depreciation in DPP3 saw an acceleration factor applied to existing assets. Commissioned assets during DPP3 saw the same acceleration factor applied in the DPP3 modelling and also for information disclosure purposes during DPP3 as required under the Input Methodologies (Clause 2.8.2(5)(b)). This means the average life for new assets once the adjustment factor is applied is now less than the 45 years.

In the modelling of accelerated depreciation for DPP4, existing assets that have a reduced life during DPP3 receive a further reduction in life. However, the modelling of new assets still assumes a life of 45 years and is adjusted for the DPP4 accelerated depreciation factor only. This means the expected life for existing assets is lower than that for new assets. If we apply the Input Methodologies clause specified above (Clause 2.8.2(5)(b)), in practice the assets commissioned during DPP4 will be assigned a life with both the DPP3 and DPP4 accelerated depreciation factor and depreciate more rapidly than expected in the DPP4 asset stranding model and financial model.

We have identified another modelling issue concerning accelerated depreciation. The Draft Determination for DPP4 (the Determination) specifies the depreciation for existing assets that will apply for DPP4. It is difficult to exactly meet the Determination requirement. The depreciation specified in the Determination reflects the DPP financial model and includes assumptions around revaluation of assets and the corresponding depreciation of those revaluations. The Determination also specifies the average remaining life for existing assets at the beginning of DPP4.

In practice, the lives of existing assets are updated at the beginning of the DPP period in line with the relevant DPP determination. However, if the revaluations based on actual CPI are different from those modelled, the depreciation across the period will be different to that specified in the Determination.

Moreover, specified accelerated depreciation assumes a forecast Consumer Price Index (CPI) for asset revaluations and the corresponding depreciation. If the actual CPI exceeds the modelled CPI, the allowed depreciation will be lower than the true economic depreciation, as assets are revalued at a higher actual CPI in practice. Conversely, if the actual CPI is lower than assumed, the allowed depreciation will exceed the actual depreciation. This mismatch means the regulatory allowance may not accurately reflect the real-world revaluation of assets. In its submission on the issues paper[16] Vector noted that, "… in DPP3 the Commission assumed a forecasted revaluation rate of 2% in its asset stranding model, however outturn inflation was higher. This results in existing assets at the start of the DPP not achieving the

[16] https://blob-static.vector.co.nz/blob/vector/media/vector-2025/gpb-dpp4-issues-paper-vector-submission.pdf P30

expected written down value at the end of the period as the outturn revaluation rate has eroded the expected write down impact from the acceleration."

Recommendation to deal with modelling and implementation issues:

To address the discrepancy between the accelerated depreciation factors applied to new and existing assets, we recommend aligning the accelerated depreciation factor for new assets and existing assets thereby reducing the life of new assets using the DPP3 plus the DPP4 accelerated depreciation factor.

To achieve the Commission's intended accelerated depreciation write-down when actual CPI differs from the modelled CPI, the specified depreciation should be adjusted to reflect actual CPI. This will result in a depreciation amount that will differ from that specified in the Determination.

We believe that resolving this issue is consistent with regulatory intent of accelerated depreciation. This ensures total depreciation recovered over the asset life matches the intended accelerated path, regardless of inflation outcomes.

Recommendations on accelerated depreciation and scenario modelling

While a lot has changed since 2022, the Commission has continued to apply the same scenarios to model depreciation allowances under the DPP. The GIFWG has modelled a broader range of scenarios which suggests that while the Commission's draft DPP4 acceleration factors help to mitigate stranding risk, a material risk of unrecovered capital remains.

We appreciate that making significant changes to scenario modelling at this stage in the process creates challenges since stakeholders do not have the opportunity to provide input into the new scenarios. We therefore recommend that the Commission uses the analysis carried out by GIFWG to inform how it can best reflect the current gas industry dynamics in its DPP4 reset decision. In our view the evidence clearly supports:

- **Adding an earlier wind-down scenario.** This could be done either by substituting the 2050 scenario for a 2040 scenario or adding a 2040 scenario alongside the existing two scenarios and applying an equal weighting. We have tested the consumer impacts of these changes, which we believe are consistent with other conclusions in the draft decision (for example on affordability). The first approach would result in a real increase in maximum allowable revenue for our gas transmission business of around 1% p.a. over DPP4, while the second approach would increase real transmission revenues by 2% p.a over DPP4. Of course, if the Commission's scenarios reflect the eventual reality of the economic lives of our assets then this makes no difference to the net present value of lifetime revenues.

- **Shifting the weighting towards earlier scenarios.** Rather than placing a two-thirds weighting on a later wind-down, the evidence suggests that more weight should be applied to the earlier scenario (whether 2040 or 2050). We estimate that shifting the weighting towards the 2050 scenario would increase real gas transmission revenues by 1% p.a. over the DPP4 period. This would reduce the cost burden on future gas customers, which will be a smaller pool of customers to allocate costs among.

3) Expenditure forecasting

The energy transition is driving significant shifts in consumer energy preferences and impacting existing asset management practices, network demand and operations. In response, we have developed capex and opex forecasts that will improve our capability to adapt to the changing environment, and we continue to refine these forecasts in our annual Asset Management Plans (AMPs).

This section of our submission focuses on the expenditure allowances in the draft decision. We provide more evidence on our expenditure forecasts in areas where the Commission has not allowed expenditure in the draft decision and explain why this expenditure is in the long-term interests of consumers. We believe our approach aligns with the Commission's view that network right sizing, which in our view includes the decommissioning of existing redundant assets, helps to manage the risk of asset stranding.

Opex forecasting: Base year non-recurring costs/savings adjustment and removing upward /downward bias

The Commission indicated in the draft decision the intention to use 2025 data for the base year for the final DPP decision. This will be applied unless the Commission is not satisfied that RY2025 opex appropriately reflects an efficient level, once non-recurring amounts have been taken into account.[17]

We recommend that the base year should also be adjusted for non-recurring savings, not just non-recurring costs so that it is free from both, upward and downward bias. The Commission excludes non-recurring expenses because they are not required to be incurred every year and including these would inflate future allowances.

Similarly, if in the base year a business achieved a one-off cost reduction or temporary underspends or deferrals resulting in lower levels of opex that are not sustainable, then those savings need to be adjusted for efficient opex levels otherwise:

- the base year will be artificially low
- future allowances will be systematically understated
- businesses will be penalised for a one-off saving (particularly given that there is no Incremental Rolling Incentive Scheme for gas pipelines)
- from an economic efficiency perspective, this is as distortive as including one-off costs.

In RY25 we experienced some temporary cost savings due to:

- Vacant senior management positions (i.e. CFO)

[17] https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Gas-DPP4-Draft-decision-reasons-paper-Attachments-AH-27-November-2025.pdf C40

- One-off SaaS cost savings due to project being capitalised
- Efficiency savings as corporate services costs shared amongst group businesses including Firstlight. We will not be able to make these efficiency savings going forward given the pending sale and break up of Clarus, which provides the current benefits that can be passed onto consumers.[18]

Because of commercial sensitivity of the cost savings, we have provided the dollar values in Appendix D. We recommend that the Commissions adjusts our opex levels for these savings to remove downward bias (alongside its removal of additional one-off costs).

Opex forecasting – step changes

The Commission's draft decision notes that historical opex may not fully reflect future operational requirements, and our experience strongly supports this view. As the energy transition accelerates, our networks are facing new operational demands and increasing complexity that cannot be met within historic spending levels.

We are proactively adopting improved asset management practices, enhancing operational capability, and shifting toward efficient, opex based solutions where these avoid long term capital investment and reduce overall cost to the consumer (i.e. pass-through only recovery as opposed to additional return on spend). These changes require targeted step change adjustments to opex allowances.

The primary objective of these step changes is to enable the decommissioning of redundant assets, enhance forecasting and planning capabilities, additional support for increased urbanisation around our rural pipelines, and keeping pace with advancements in cyber security and SaaS.

Substituting opex and capex

We support the Commission's position on substituting opex for capex. We appreciate that the draft decision recognises the value of this flexibility, as it enables gas pipeline businesses to respond to uncertainty and manage risk in a way that promotes the long-term interests of consumers. In particular, we consider the development of short-term interventions to defer or avoid significant long-term investments to be both appropriate and necessary. This approach minimises the risk of asset stranding, ensures continued safety and reliability of supply and helps maintain affordability for consumers during a period of declining demand.

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[18] Igneo Infrastructure Partners' announcement of the sale is available at https://www.igneoip.com/australia/en/institutional/news-and-insights/press/igneo-enters-into-agreements-to-sell-its-interests-in-clarus.html

We view this as an important step toward future DPP resets and for GPBs to remain adaptive to changing market conditions.

The costs in this section are confidential and commercially sensitive – not for public release.

Improved Forecasting and Planning

NZ$ (2027-2031)	Specified in AMP	Specified in Draft DPP decision	Funding Shortfall
Transmission	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Distribution	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

The Commission's draft decision emphasises the importance and complexity of planning for network rightsizing and adapting to declining demand. Improving our forecasting capability is essential to inform future decisions and avoid suboptimal investment outcomes.

The Commission noted in table C5:

> *"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."*

The activities related to the step change for improved forecasting and planning have no relationship to the existing blended gases allowance provided by the Commission, which are limited to adapting our current forecasting and planning practices.

We need to implement a deeper form of analysis to determine the appropriate asset renewal activity or whether using an opex based solution is the better option to prevent long term capital investment. The process will entail detailed network location-based analysis to understand the future viability of the network in that specific area. This will need to include an assessment of the consumer make-up on that area of the network and a development of a quantitative risk assessment to determine consequence and probability of failure.

This new approach requires additional resources to complete, both in terms of doing the analysis and optioneering and then developing and implementing the required asset information system and process changes.

We lay out our detailed assessment and analysis to support this position below.

We need to shift away from growth-based forecasting and planning to a risk-based approach

We need to transition from traditional growth-based planning to a risk-based approach, prioritising capital decisions based on an increased analysis of asset failure risks and developing opex-based solutions to address future investment needs. When completing this work, we must simulate a wider array of demand/supply scenarios and assess technical and commercial risks at a more granular level. This includes location-specific analysis of major customers and infrastructure, ensuring capital investment decisions align with the future operation of the network.

Within the draft decision it appears that a correlation was drawn between blended gases and improved forecasting and planning. This step is not related to blended gases but a change to our current forecasting and planning practices, as they are no longer sufficient for the current environment in which we operate.

The additional expenditure will be used to develop and embed a new planning methodology and process, conduct detailed location based optioneering studies and risk assessments to understand the likelihood of network viability, probability and consequence of failure, engage external vendors to modify asset information systems to accommodate additional data and risk assessment information, increase planning and engineering resource, and complete relevant training for the wider operations staff.

Consumers benefit through reduced capital investments

Improved forecasting and planning directly benefits consumers by ensuring that our investment decisions are aligned with future network operation and utilising opex based interventions to reduce capital investment. This means that consumers are less likely to bear the financial burden of stranded assets or inefficient capital deployment. Enhanced forecasting also allows us to better anticipate changes in demand, such as those driven by decarbonisation policies or industrial closures, enabling the network to adapt more effectively.

Breakdown of Costs

After initial implementation costs, annual costs associated with this step are primarily associated with the engagement of new staff to carry out this work and updating asset information systems to record the initial assessment and review the work on a regular basis.

One-off uplift to establish capability

Activity	Estimated Cost ($'000)	Description
External vendor engagement	[REDACTED]	Specialist support for forecasting methodology design, risk management changes, and process integration.
Training and change management	[REDACTED]	Upskilling internal teams on new forecasting tools and risk-based planning frameworks.
System development and integration	[REDACTED]	Enhancements to asset information systems to enable location-based viability analysis.
Process development and documentation	[REDACTED]	Creation of new planning workflows, optioneering templates, and governance structures.
Total Implementation	[REDACTED]	

Annual activities and costs

Activity	Transmission Estimated Annual Cost ($'000)	Distribution Estimated Annual Cost ($'000)	Description
Labour (Engineering and Planning FTE uplift)	[REDACTED]	[REDACTED]	Dedicated engineering and planning resources for detailed network location-based viability assessments, optioneering, and quantitative risk assessment.
Quantitative risk assessment updates	[REDACTED]	[REDACTED]	Regular refresh of risk models (probability and consequence of failure) and integration into planning cycles.
System maintenance and enhancements	[REDACTED]	[REDACTED]	Ongoing updates to asset information systems and forecasting tools to reflect new data and methodologies.
Training and continuous improvement	[REDACTED]	[REDACTED]	Annual training refresh for staff and process improvement initiatives to maintain capability.
Governance and reporting	[REDACTED]	[REDACTED]	Oversight, compliance reporting, and refinement of planning frameworks.

Activity	Transmission Estimated Annual Cost ($'000)	Distribution Estimated Annual Cost ($'000)	Description
Annual cost	**[REDACTED]**	**[REDACTED]**	

Progress will be slowed without adequate funding

Without the forecast expenditure, the necessary adaptation of our planning processes will still need to occur, but progress will be much slower and less effective in the near term. Resulting in near term investment decisions to be potentially made with suboptimal information, risking potential over investment in assets, poor utilisation or delayed decision-making on critical investments.

Station and Compressor Decommissioning

NZ$ (2027-2031)	Specified in AMP	Specified in Draft DPP decision	Funding Shortfall
Transmission	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Distribution	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

Proactive network rightsizing is an important response to preventing long term asset stranding and ongoing maintenance costs. In the draft response the Commission declined our step associated with Station and Compressor decommissioning, noting in Table C5:

> *"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."*

This reasoning does not reflect the nature of the work we are seeking to undertake. The assets we propose to decommission are *already redundant today* — they no longer support operational requirements, are not needed for N-1 redundancy, and in some cases (such as a **[REDACTED]**) relate to consumers who have exited the gas market entirely. Their decommissioning is not tied to the eventual, full end-of-life decommissioning of the transmission system (whenever that may occur). Rather, this work represents prudent, near-term expenditure that prevents ongoing and unnecessary lifecycle costs, which would be inefficient costs for consumers to bear.

The Commission itself acknowledges in paragraph D97 that:

> *"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)."*

Rightsizing the network includes the timely removal of assets that no longer serve a functional or economic purpose. Beginning this work in DPP4 ensures that redundant equipment is not retained indefinitely, incurring further maintenance, compliance, and safety-related costs.

Under the current DPP settings, opex allowances fund ongoing maintenance of these assets, but *no allowance exists to remove them*, creating a potentially perverse incentive: consumers continue paying for the upkeep of plant that has no purpose or benefit, because maintenance is funded but decommissioning is not. The result is higher long-term costs — consumers pay the ongoing opex today *and* will ultimately pay the decommissioning cost in the future, rather than sharing that cost fairly across current and past users.

By enabling modest decommissioning activity in DPP4, these evergreen maintenance costs can be avoided, and future consumers are not left solely bearing the financial burden of removing assets that have already ceased to deliver benefit. This approach aligns with the Commission's intent to reduce long-term stranding risk and ensure efficient cost recovery.

We lay out our detailed assessment and analysis to support this position below.

Our proposal is to decommission some redundant gas transmission assets

This work is not about legal decommissioning obligations but about removing redundant or poorly utilised assets that no longer serve a functional or economic purpose. For example, the Kawerau compressor station currently incurs approximately **[REDACTED]** per annum in opex to remain compliant and operational, despite having no fundamental role in the network. A one-off investment estimated at **[REDACTED]** would allow the site to be safely isolated and eliminate ongoing costs.

The Commission appears to agree this type of work is beneficial:

> "...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."[19]

Without specific allowances, the current DPP structure creates artificial barriers to decommissioning, as the cost to remove redundant assets often exceeds the available opex, particularly in the later years of the period when allowances decline. This programme ensures that assets which are a financial burden are removed promptly, avoiding unnecessary capex and opex and enabling long-term cost reductions.

Between FY2027 and FY2031, we plan to permanently decommission the following five redundant compressor units and three existing stations:

- **Kapuni (Unit 5)**: We improved the capacity of units 2 and 3 making Unit 5 redundant and no longer required for network operation or N-1 redundancy. In addition to its

[19] Paragraph D97 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)

age, Unit 5 requires substantial capital investment to improve reliability, operability and modernise safety systems.

- **Rotowaro (Unit 6)**: The closing of gas fired power stations in Auckland and the Marsden Point refinery has significantly reduced the gas throughput at Rotowaro. Due to this, the station no longer requires two turbine compressors to meet the redundancy requirements. Unit #6 failed a hot end inspection on several end-of-life parts, making it not economical to repair.
- **Mahoenui (Unit 3)**: Mahoenui Compressor Station lies on the 200Line and historically fed gas to Hamilton and supported the Pokuru Compressor Station. Due to pipeline condition, the 200Line is isolated. As Rotowaro CS has excess capacity now, the Hamilton and Pokuru demands can be fed from Rotowaro Compressor Station, leaving Mahoenui Compressor Station as a contingency station only for use with the 200Line. For this use case, three compressors are not required. The gas cooler on Mahoenui #3 has also failed and is not economical to repair for a machine which is not required to meet demand.
- **Kawerau (Unit 1 and Unit 2)**: The Kawerau Compressor Station has not been operated for a very long time and is not required to meet the gas demands of Gisborne.
- **Marsden Delivery Point**: A large user has exited the market leaving the existing station and assets oversized for the remaining consumer. A partial decommissioning is required to right size the gas equipment assets and reduce lifecycle maintenance costs.
- **Alfriston Delivery Point:** A direct connect consumer has exited the market leaving the station redundant. The station is required to be physically isolated from the pipeline, assets removed and station left in situ, reducing lifecycle costs.
- **Mangatainoka Delivery Point:** A direct connect consumer has exited the market leaving the station redundant. The station is required to be physically isolated from the pipeline, assets removed and station left in situ, reducing lifecycle costs.

Additionally, approximately 20 low-revenue delivery points (each earning under $10,000 annually) have been identified as potentially uneconomic. The average annual opex across the 10 lowest-margin stations combined is **[REDACTED]**, while the cost to remove and make a single station safe is estimated at **[REDACTED]**. Without specific allowances, the current DPP structure incentivises continued operation of uneconomic assets, as the cost to decommission exceeds the available opex. This programme aims to eliminate evergreen expenditure in non-viable assets and enable timely removal, reducing long-term opex and capex exposure.

Decommissioning of these redundant assets is inevitable and avoids expenditure in future DPPs

Decommissioning redundant compressor units and stations are required at some point in time, either during following DPP periods or at the completion of a full or partial network shutdown. If we begin this work in DPP4 we can begin to reduce lifecycle maintenance and operational costs now, which will eventually help to contain or lower transmission charges passed on to consumers in future periods. Any additional expenditure allocated to accommodate decommissioning now will prevent the inevitable future expense of completing this work.

Importantly, decommissioning during DPP4 mean costs to consumers are better spread out across the remaining life of the network. The alternative is these costs are pushed on to a smaller future pool of network consumers (at a higher per capita cost).

Breakdown of costs

This expenditure is related to labour costs associated with developing decommissioning procedures, physical site works, updating documentation and SCADA systems. There will be some minor material cost to purchase equipment for permanent isolation from all natural gas sources.

Cost Category	Work Activity	Estimated Cost ($'000)
Procedure development	Develop management of change (MoC), permit to work, isolation plans and decommissioning procedures.	**[REDACTED]**
Physical site works labour	Completing decommissioning works and isolations.	**[REDACTED]**
Documentation and records updates	Updating drawings, asset records and procedures.	**[REDACTED]**
Scada system updates	Control logic changes, setpoint removals, trending, alarm strategy changes.	**[REDACTED]**
Materials – isolation equipment	Material components — blinds, valves, signage, and purging equipment.	**[REDACTED]**
Total		**[REDACTED]**

Risks if not funded

Without an increase in operational expenditure, we will be unable to decommission existing redundant compressor units and stations, resulting in:

- Continued maintenance and operational costs for redundant assets.
- Increased risk of failure from ageing equipment with known safety and reliability issues.
- Artificial barriers to decommissioning due to lack of funding, leading to continued lifecycle costs

- Increased future burden on future gas consumers to remove from service assets which should have should have been shared with previous/current consumers of the system.

The case for removal is clear: the cost to decommission now is lower than the ongoing opex burden, and materially lower than deferring removal until full network closure.

Legal Resource for Urbanisation

NZ$ (2027-2031)	Specified in AMP	Specified in Draft DPP decision	Funding Shortfall
Transmission	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Distribution	n.a.	n.a.	n.a.

Over the previous three years in DPP3 we have seen a significant increase in work adjacent to our pipeline. This work is driven by the development of rural land being converted to urban subdivisions and the development of infrastructure by local and central government.

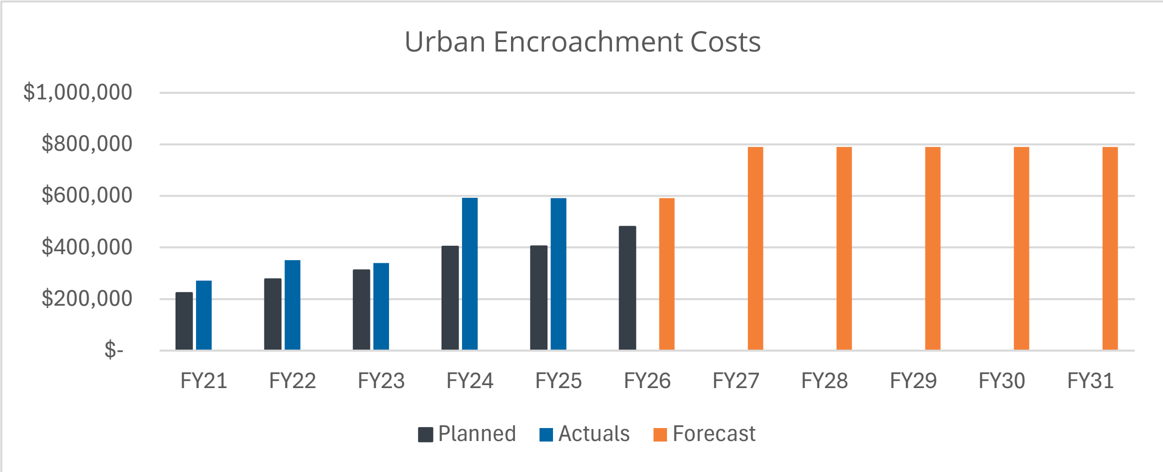
The Commission noted in table C5.

> *"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."*

The following graph shows an increase in expenditure from FY24 to FY26 above previous years expenditure, and we expect costs to increase in the next five years - as can be seen RY25 has already exceeded our planned budget. This increase in expenditure is largely out of our control as the government has begun large-scale development of State Highway One and as Auckland urban development expands further to the south.

This encroachment encompasses an additional nine kilometres of pipeline above the existing 16 kilometres which is in progress and requires additional resources to engage with developers, government and construction firms.

Urban Encroachment Costs



We require more support to manage urbanisation and infrastructure driven projects

We have forecast an annual increase of $200k between FY2027 and FY2031 for additional legal support to manage urbanisation pressures affecting our gas transmission network. This funding covers external legal expertise to address an increase in urban encroachment from residential developments and infrastructure projects led by councils and central government. We have issued legal notices to landowners encroaching on pipeline easements and engaged with councils on planning matters such as Auckland's Plan Change 120 and Tauranga's water main proposals.

Activities include:

- reviewing district plan changes,
- securing legal protections for pipeline corridors,
- negotiating infrastructure relocation agreements,
- enforcing easement rights,
- participation in hearings,
- preparation of technical evidence, and
- coordination with planning consultants.

A detailed list of all current developments adjacent to our pipeline that support the request for an increased allowance can be found in Appendix C.

Recovering costs is in the interest of the consumers

Allocating additional legal resource enables us to ensure that costs arising from urban development are appropriately recovered from third parties, such as land developers, rather than being borne by consumers. (i.e. avoiding an unfair wealth transfer, and ensuring the developer pays for their commercial interests and activities).

Risks if not funded

Urbanisation continues to increase around our network, a lack of additional resources could lead to missed plan changes, encroachment on our network without approval, not enforcing easement rights and legal precedent of us paying for the safety improvements to maintain compliance or relocation of network assets.

Capex forecasting – Non network capex

This Section should be read in conjunction with supporting detail in Appendix B

While we generally agree with reviewing AMP forecasts against historical expenditure averages, this at times clashes with an additional programme or project that arises through asset planning which requires an increase in a specific expenditure category.

The draft decision on non-network capex allowances for gas transmission has the effect of excluding work required on the Open Access Transmission Information System (OATIS) (see paragraph 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."*

Our historical expenditure for non-network capex does not include expenditure related to OATIS. The OATIS upgrade is a unique case where partial capex funding is required due to the bespoke nature of the system and the intellectual property we retain. While the re-platforming does not change core OATIS functionality, it requires replacing the end-of-life .NET codebase, custom webpage code, and bespoke integration components so we can operate securely on modern cloud infrastructure. These elements qualify as capital expenditure under accounting rules, whereas all other project activities such as discovery, planning, testing, operating system upgrades, database upgrades, infrastructure changes, data cleansing, data migration, cloud migration work, and cloud hosted configuration must be treated as opex. This work is mandatory because OATIS currently relies on several technologies that reach vendor end-of-support between 2028 and 2030.

The draft decision to cap non-network capex at historical averages inadvertently excludes OATIS, because historical spend does not contain any comparable re-platforming activity. This upgrade is an episodic, asset-driven requirement, not a discretionary system enhancement. Firstgas has prudently reprioritised its broader capex portfolio and substantially reduced total investment to minimise consumer impact; however, without the additional **[REDACTED]** in FY27–FY28, we cannot complete the capital components required to bring OATIS onto a supported platform. Failing to fund this work risks unplanned outages, reactive emergency spend, or price shocks if a failure forces an accelerated replacement.

Completing the re-platforming during DPP4 reduces long-term technology risk, stabilises future maintenance cycles, and enables a transition to a more predictable, cloud-based operating model that will be cheaper and safer to maintain over the coming regulatory periods.

Capex forecasting – distribution consumer connection and system growth capex

The Commission’s direction for capex spend across new connections and system growth aligns with Firstgas’ intended strategy over the course of the DPP4 period. The first stage of this strategy will be to implement a new Capital Contribution Policy from 1 April 2026 allowing a maximum cap of 40% Firstgas spend across all customer-initiated capital expenditure. This is higher than the 20% contribution assumed in the draft decision.

We believe that this initial 40% cap is an appropriate position entering DPP4. This policy will significantly increase capital contributions while continuing to recognise the benefits that new customers bring across the fixed-costs of the network. This more gradual approach to increasing customer contributions will also support consumers partway through projects who have made specification commitments based on existing policy. While a significant drop off in new connection activity is forecast because of higher contributions, a 40% capex spend will continue to support energy choice in the market and meet consumers desire for gas which continues to be demonstrated across market research and consumer feedback.

Higher contributions will naturally discourage low volume loads but still allow high volume and value customers to connect and support continued utilisation of the network. These high value new connections received during DPP4 will prove particularly beneficial by introducing new appliance lifecycles and spreading costs amongst a greater number of customers towards the end of the network's commercial life.

Ongoing contractual agreements based on existing and historical contribution policy may result in instances where actual capital spend in DPP4 goes beyond the 40% cap. The impact of this spend is considered minimal in context to the wider capital expenditure forecasts but should be acknowledged in the context of this response.

4) Network revenue and pricing

The draft decision is accompanied by a change to the input methodologies for gas transmission to adjust the revenue cap wash-up. This section provides our views on those changes, and also reviews the way that Constant Price Revenue Growth (CPRG) has been forecast for our gas distribution business.

Gas transmission revenue wash-up issues

Firstgas acknowledges the Commission's and MGUG's concerns regarding large in-period increases in transmission prices during DPP3. As highlighted in our submission on the Issues Paper, revenue wash-ups have been caused by a variety of factors in recent years. We agree that gas consumers can benefit from a pricing regime that limits volatility and promotes predictable outcomes to the extent practicable.

However, we have concerns with the way in which the Commission proposes to implement revenue smoothing, particularly in the treatment of recoverable costs. Under the Commission's draft decision, the amount of revenue that a gas transmission business can earn in a year is a function of the previous year's estimate of recoverable costs.

In our case, recoverable costs are overwhelmingly made up of balancing and fuel gas costs. These costs are very difficult to predict, as the quantity of gas required to balance the transmission system and the price of gas are both difficult to predict. Ideally, the costs of balancing and fuel gas will be borne by the shippers benefitting from that expenditure; that is, from the parties using the transmission system in that year.

The Commission's proposed change to the revenue wash-up has the potential to frustrate this outcome of beneficiaries paying for the balancing and fuel gas needed to service their demand. Consider the case where in Year N Firstgas sets prices using a particular gas price estimate to forecast recoverable costs. Shortly thereafter, the gas market experiences a disruption that leads to sustained high prices. In Year N, actual recoverable costs will be higher than forecast, potentially leading to a shortfall in revenue. In Year N+1, revenue will be constrained by the previous, now out-of-date, recoverable costs forecast, potentially leading to a second revenue shortfall. The wash-ups from both of these years will be borne by shippers in future years. Using an updated forecast in the second year could potentially have avoided a second revenue shortfall needing to be washed up.

As this example illustrates, the proposal to limit revenue as a function of the previous year's recoverable costs forecast may have unintended consequences for recoverable costs that are difficult to predict in imposing current costs unfairly onto future gas users, inconsistent with the economic principles underpinning this mechanism. We therefore recommend that the Commission includes the current year's recoverable costs forecast in the calculation of revenue smoothing limit.

Gas distribution constant price revenue growth analysis

In the 2023 input methodologies review the Commission decided to retain a weighted average price cap (WAPC) for gas distribution services. In that process, we submitted that a revenue cap is a more appropriate form of control for GDBs (in support of submissions on this point made by Vector and Powerco). We understand that the next opportunity to reconsider that decision will be the next input methodologies review, expected in 2030.

Ahead of the next IMs review, we support the GIFWG work on a hybrid form of control, which we see as a sensible middle ground. Under this model (which applies to Jemena's gas networks in Australia) the key features of a WAPC are retained but the extreme outcomes are mitigated through "caps" and "collars" on the level of risk that suppliers or consumers bear.

The draft decision does not implement a hybrid form of control, which means that our main interest is to ensure that the CPRG forecasts made in the draft decision are reasonable. We are particularly concerned with the risk that CPRG forecasts that are too high will overestimate the future revenues earned by our gas distribution business.

The Commission engaged Concept Consulting to review GDB forecasts of future customer numbers and gas volumes. Concept prepared its own forecasts and then compared them with GDB forecasts, ultimately concluding that GDB forecasts appeared reasonable.

We support the use of GDB growth forecasts for setting CPRG. This has the benefit of being consistent with other parameters in supplier AMPs that are a function of future ICP numbers or gas throughput. The most obvious example is customer connection capex forecasts, which are driven by new connection requests. However, there are other, more subtle linkages between future demand and forecast expenditures.

While we agree with the Commission's decision to use GDB demand forecasts, we do not agree with all of the analysis in the Concept report:

- Concept states (on p14) that "Consumers (and, ultimately, NZ Inc) can avoid gas network and retail costs from switching to electricity". While it is true that individual consumers can avoid gas network costs by removing their access to gas, overall network costs cannot be avoided and are simply shifted onto other gas consumers when disconnections occur. The reference to 'NZ Inc' is therefore clearly erroneous.
- Concept's report appears to understate the unique value proposition of gas, for example stating (on p14) that "large, exterior, mains pressure cylinders now offer an equivalent service for water heating" to instantaneous gas hot water heaters. This claim is arguable at best. Once cylinder hot water is depleted, users need to wait for recovery, whereas gas instantaneous continuously delivers hot water indefinitely.

This picks up a broader point from the Pinstriped Leopard customer research that "residential customers [are] far more emotive about the benefits of natural gas".[20]

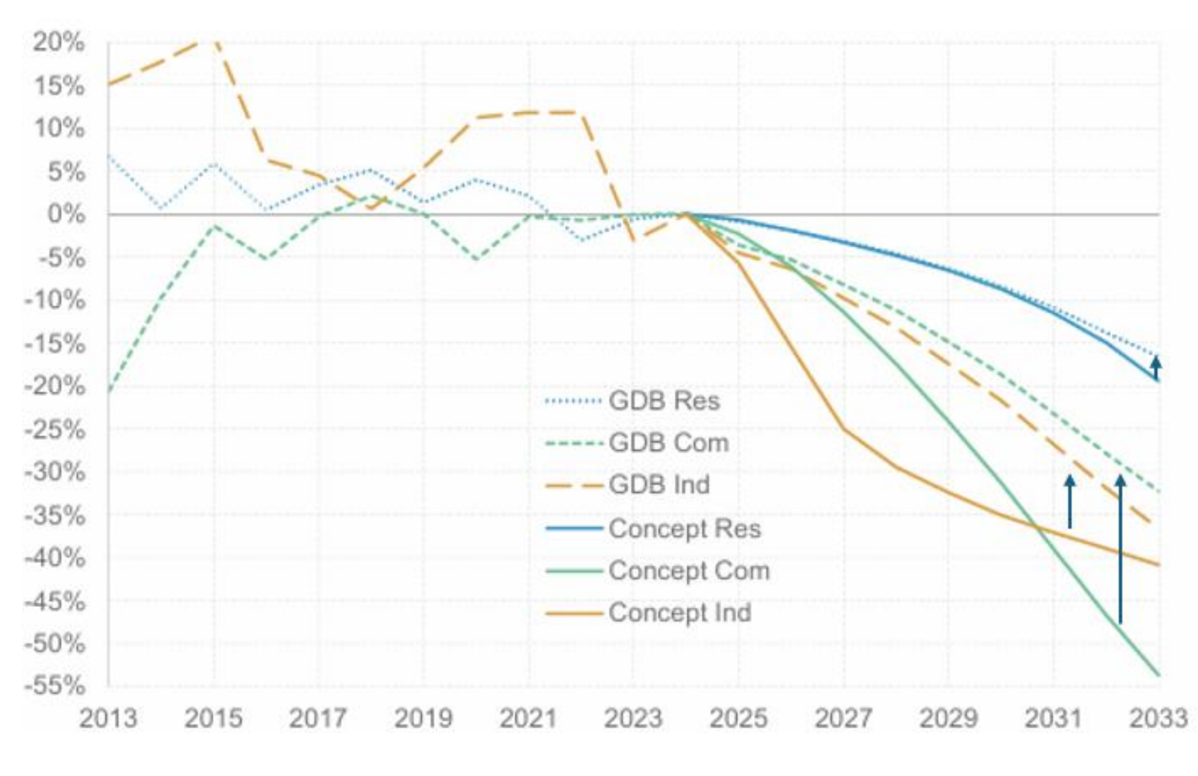
- Concept uses a discount rate of 5 percent to annualise the cost of new appliances (with different lifetimes applying to different appliances). We understand that this is based on interest rates applying to home loans (current fixed rates vary between 4.59% and 5.29% depending on term). Economic research suggests that there is no universal rate of time preference for investments in household appliances and that discount rates often exceed the market interest rate.[21] This is symptomatic of humanity's widespread 'present bias' that over weights present-day effects.[22] We suggest, at a minimum, using sensitivity analysis with a higher discount rate (such as 10 percent) to evaluate impacts on Concept's forecasts.

These observations on Concept's analysis tend to support the use of GDB forecasts, which are grounded in market trends rather than economic analysis. We expect that if Concept updated its analysis (particularly by using a range of higher discount rates to reflect actual New Zealand household decisions), then Concept's forecasts would better align with GDB forecasts. i.e. the gap between Concept forecasts and GDB forecasts can be partially explained by the use of a single, low discount rate.

As shown in the graph below, Concept's forecasts are lower for each customer type than Firstgas' AMP forecasts. While the gap appears smallest for residential customers, the impact on revenue is likely to be significant (due to the high proportion of distribution revenue from residential customers).

[20] See Firstgas2C-PowerCo-26-Vector-Attachment-C-Qualitative-Research-Report-Summary-prepared-by-Pinstriped-Leopard-24-July-2025.pdf, slide 8 "Attitudes towards gas"
[21] Haq and Wiess (2018) "Time preference and consumer discount rates – Insights for accelerating the adoption of efficient energy and transport technologies". Available here: Time preference and consumer discount rates - Insights for accelerating the adoption of efficient energy and transport technologies - CORE
[22] Peter Maxted: "There is widespread evidence that consumers exhibit "present bias" across a variety of decision-making contexts." in section 1 of Present Bias Unconstrained: Consumption, Welfare, and the Present-Bias Dilemma published in The Quarterly Journal of Economics, Volume 140, Issue 4, November 2025, Pages 2963–3013, https://doi.org/10.1093/qje/qjaf030

Demand movement for Firstgas relative to 2014 (Figure 11 Concept report)



5) Disconnections, rightsizing and decommissioning

We disagree with the Commission's draft decision to take no action, in relation to DPP4, to account for large-scale decommissioning in future DPPs. A ring-fenced decommissioning fund (perhaps a trust) should be established now because:

- eventual large-scale wind-down of gas networks is highly credible
- large-scale decommissioning is credibly a material future cost
- present-day gas users should be contributing toward those eventual costs.

We also agree that there appear to be no regulatory changes needed during DPP4 to account for network rightsizing, provided that sufficient expenditure allowances are in place to fund specific anticipated activities. If the Commission is unable to approve allowances for valid decommissioning costs, then there is a regulatory failure that must be addressed.

We agree with the Commission's plan to monitor disconnection costs.

Large-scale network decommissioning

On the topic of large-scale network decommissioning in future DPP periods, the Commission concluded:

> "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."[23]

The Commission's expanded on the reasons for its decision, saying:

> "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.
>
> 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.
>
> 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.

[23] Paragraph F21 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)

> 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)."[24]

We disagree with the Commission's rationale and conclusion.

As a member of the GIFWG, we have contributed to new information about the costs of decommissioning gas distribution pipelines and so refer the Commission to that submission as supplementary to our arguments below.

We agree with the Commission that there is a high level of uncertainty about all aspects of future decommissioning costs. Nobody knows how much decommissioning will be needed, by when, the costs at that time, which parties have exactly what decommissioning obligations (if any), or what the resulting accounting practice ought to be. However, the three facts set out in the following table are sufficient to justify establishing a ringfenced decommissioning fund during DPP4:

Facts that justify a ring-fenced decommissioning fund	Rationale to establish each fact
Eventual large-scale wind-down of gas networks is highly credible	• Many of the same factors that convinced the Commission to introduce accelerated depreciation are making it more likely that large-scale decommissioning will be needed (and needed sooner). • The only scenario that could prevent the eventual need for large-scale decommissioning of gas networks is large-scale repurposing. • Even in the unlikely event that gas pipelines are used for their full physical lives, decommissioning would still be needed at that time.
Large-scale decommissioning is credibly a material future cost	• Decommissioning of the ~19,000 km of gas distribution pipelines and associated above-ground assets was estimated by GPA as $193 million, though that was based on many idealised assumptions that won't hold in real-world application. • Decommissioning of the ~2,500 km of gas transmission pipelines and the substantial (and much more costly-to-decommission) above-ground assets will add a sizable contribution to those costs. For example, in DPP4 we have sought **[REDACTED]** to decommission various assets,

[24] Paragraphs F22-24 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)

	including five compressor units and three stations. While compressor stations are likely the most complicated and expensive stations to decommission, our GTB has over 150 stations (offtake, intake, scraper, metering) that could require decommissioning. • Accordingly, the eventual real-world costs of large-scale decommissioning is easily into the hundreds of millions.
Present-day gas users should be contributing toward those eventual costs	• When people are charged in proportion to how much they use infrastructure, they face prices that reflect the real costs they impose on the system, including congestion, wear and tear, and the need for future capacity. This price signal helps allocate scarce infrastructure more efficiently, more fairly and with fiscal sustainability. • The same economic arguments apply for decommissioning costs. In a workably competitive market, suppliers do not expect to recover decommissioning costs at end-of-life from the then-remaining customers.

If the Commission accepts the above facts, we see it as inevitable that the Commission must prioritise collecting *some* money from gas users in DPP4 rather than waiting and obtaining higher certainty about the possible costs. As we argued in our submission on the Commission's Issues Paper, declining gas production means gas DPP4 represents an outsized portion of all future gas use. This makes DPP4 the *most* important DPP for collecting some customer contribution toward future decommissioning.

The Commission's decision should also place greater weight on the fairness of cost allocation amongst gas consumers over time. If today's gas consumers make no contribution toward eventual decommissioning during DPP4, there will be many departing customers who have never made any contribution. The higher burden of that will fall to the then-remaining consumers, who will feel aggrieved at the unfairness of the situation.

While we agree that the Commission should be interested in improving the quality of information available to it, we believe that the clarity sought by the Commission is less important than the imperative to commence customer contributions during DPP4. In particular:

- Clarity about 'the nature of decommissioning liabilities' would help clarify both the amount of work required for those assets needing decommissioning and which party (or parties, if any) have what obligations. However:
    - clarity about how much it would cost to decommission a particular asset doesn't help resolve which assets will need to be decommissioned by when
    - a flexible, principles-based decommissioning fund would be agnostic about which party is responsible. For example, if the Crown takes on some

decommissioning liability it would be appropriate for it to be eligible to receive disbursements from the decommissioning fund.

- Clarity about the 'the type/scale of costs involved for GPBs' could be improved for the types of costs but the scale of costs is tied to fundamentally uncertain and hard-to-predict factors like future gas production, the cost of gas substitutes and Government energy policy. The cost to decommission a particular type of asset could be clarified during DPP4, but the most important factors will remain hard to predict (both in 2029 and beyond). The Commission correctly observes that decommissioning costs "…may vary across GPBs, depend on the state of their networks at the time of retirement, and decommissioning may be progressive"[25] but offers no rationale for why this would be substantially clearer in DPP5.
- Clarity about "how GPBs propose to manage decommissioning (and the associated risks) commercially"[26] and or GPBs' GAAP treatment may not be known before DPP5 and is, regardless, not a barrier to acting now. As noted above, we contend a flexible, principles-based decommissioning fund would be agnostic about which party is responsible.
- Clarity about the 'public policy environment' is unlikely to be achievable. If the last ten years are any indication, we should expect continued changes in energy policy and little concrete guidance on government strategy through the energy transition.

The Commission also 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."[27] The Commission appears to no longer rely on this as a reason for not pursuing a decommissioning fund, but as an observation on the complexities involved.

We believe that the complexity involved is another reason for starting sooner rather than later. GPBs raised the topic of decommissioning in their March 2025 responses to the Commission's Open Letter on DPP4. At that time, the Commission considered the 'novel nature of the mechanisms' to be one of the main barriers to considering the issue for DPP4. The Commission has not taken the opportunity to progress this topic. This has shrunk the Commission's window of opportunity to the period from receiving submissions on its Draft Decision to when a Final Decision must be announced in May 2026. This tight timeframe has been created by the Commission's choice to not act sooner.

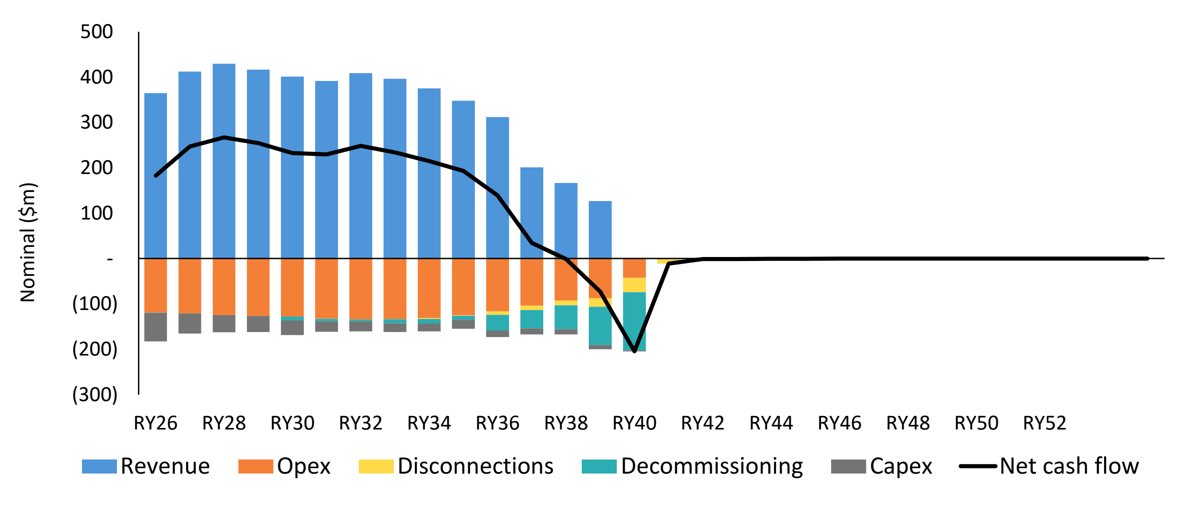
The Commission's decision to introduce accelerated depreciation provides an excellent example of where the Commission has turned its attention to a complex issue with high

[25] Paragraph F14.2 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)
[26] Paragraph F23 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)
[27] Paragraph F15 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)

uncertainty and regulated as best it can in the circumstances. The Commission's decision in DPP3 to accelerate depreciation was the correct course of action, not because it had precise clarity about the future but because the situation demanded early action. The Commission's analysis shows that consumers are in a better position as a result. Like accelerated depreciation, the need to financially provision for eventual decommissioning can be adjusted over time as better information comes available. It is not obvious whether the Commission should target (say) $20m or $30m of decommissioning contribution during DPP4, but both are clearly better than collecting $0.

GIFWG's previous scenario modelling highlights financial implications of failing to account for future costs now. The graph below shows that in an accelerated supply-driven wind-down in 2040, networks would face costs (including in safely decommissioning networks) that cannot be recovered from remaining users. While this is a scenario at one end of the range of plausible outcomes, it highlights that negative cashflows could be possible from the late 2030s. From an ex-ante Financial Capital Maintenance (FCM) perspective, commencing decommissioning cost recovery in DPP4 reduces the risk that efficient, unavoidable costs become unrecoverable as demand declines. Deferring all provision would concentrate those costs on a much smaller group of remaining consumers, leading to materially higher charges that reflect timing rather than efficiency. Early, limited contributions therefore better support FCM, smooth intergenerational cost recovery, and avoid avoidable price shocks for consumers who remain connected to the network longest.

GIFWG forecast of GPB net cash flow in a fast wind-down scenario[28]



[28] Chart shows aggregated amounts for transmission and distribution pipelines. For further detail, please refer to GIFWG analysis report (not yet public).

In our submission on the Commission's Issues Paper, we described some potential characteristics of a ring-fenced decommissioning fund. One specific implementation option the Commission should consider is the creation of a trust to hold, invest and disperse gas consumers money set aside for eventual decommissioning. While this would necessarily be bespoke and novel, some entities exist with similarities:

- The Waikato River Authority and the Waikato River Clean-up Fund Trust. Both entities (statutory bodies and registered charities) were established by Parliament under the *Waikato-Tainui Raupatu Claims (Waikato River) Settlement Act 2010*. One of the Waikato River Authority's three purposes is to "fund rehabilitation initiatives for the Waikato River in its role as trustee for the Waikato River Clean-up Trust."[29] The Trust is responsible for administering a $220 million clean-up fund over 30 years.[30] Their trust deeds are contained in Schedules 5 and 6 of that Act and could form the basis of a Commission-established trust.
- The United Kingdom's Nuclear Liabilities Fund. The Fund's purpose is "…to receive and hold monies, investments and other assets, in order to secure funding for discharging certain liabilities related to the decommissioning of eight nuclear power stations…"[31] The Fund is not responsible for decommissioning, but for investing and dispersing its funds (currently over $41 billion) for the purposes of decommissioning a defined set of assets. The fund's establishment ensures it is "protected from creditors of the operator of the nuclear power stations and the fund cannot be used as a source of general government spending."[32]

While novel for the Commission, establishing a trust is a robust and well-known path for placing assets under the control of trustees who then have some latitude (and responsibilities under the Trusts Act 2019) to give effect to the object of the trust.

Gas distribution disconnection costs

In light of submitters' concerns about disconnection[33], the Commission concluded that:

> "Given the expected increase in customers disconnecting from the gas networks, we expect disconnections to become an emerging focus over DPP4…We consider that the first step is to collect information on disconnections and monitor outcomes."[34]

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[29] Section 22(2)(c) of the Waikato-Tainui Raupatu Claims (Waikato River) Settlement Act 2010
[30] Section 1.3 of Waikato River Clean-up Trust Funding Strategy 2016
[31] https://www.nlf.uk.net/about-us/our-purpose
[32] Nuclear Liabilities Fund | Corporate Structure
[33] We note that the second sentence of paragraph E34 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H) is a direct quote from ConsumerNZ's submission, but not provided within quotation marks.
[34] Paragraphs E37-38 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)

We support this aspect of the draft decision. Monitoring is consistent with the Commission's approach not to regulate individual prices: "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."[35]

We encourage the Commission to work with the Gas Industry Company (GIC) on this topic. The Commission's narrower (network regulation) gas-related mandate will not be sufficient to help consumers understand disconnection pricing, as that is mediated through retailers and is dependent on other suppliers (such as metering providers) in addition to GDBs. GIC is proposing that its 2027 work programme will include a project focused on monitoring and providing insight to residential gas users. Ideally, the Commission's and GIC's monitoring will be efficient (avoiding duplication) and provide consumers with meaningful insight.

Network rightsizing

On the topic of network rightsizing, the Commission concluded it would consider this "as part of a regulatory process separate to the DPP4 reset process."[36] Furthermore, the Commission noted that it does "not currently have the ability to develop a withdrawal code for GPBs."[37]

We agree with the Commission's assessment of low materiality for the regulatory arrangements in DPP4 and therefore its conclusion to have this out of scope.

We note however that the Commission's Draft Decision declined to approve an allowance for ~$4.5 million of expenditure relating to GTB asset decommissioning in DPP4. We have provided further information and justification for this in Section 3 and Appendix D of this submission. If the Commission is unable to approve any allowances for valid decommissioning costs, then there is a regulatory failure that must be addressed. As noted in Appendix D, if we are unsuccessful in our allowance request, we will face perverse incentives leading to delaying of needed decommissioning and continuing maintenance costs in relation to those assets.

While the topic of network rightsizing (and especially service withdrawal) is not material in the context of the regulatory system, we appreciate this is a topic of extreme materiality to affected consumers and may cause concern amongst unaffected consumers. We aim to treat all consumers with care and respect as the industry explores this sensitive topic further.

[35] Paragraph A74 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)
[36] Paragraph F4 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)
[37] Paragraph F9 of the Commission's Gas DPP4 reset 2026 – Draft decision reasons paper (attachments A-H)

6) Quality Standards

Alongside the maximum revenue that gas pipeline businesses can earn, the DPP reset determines the quality standards that must be met. This section comments on two aspects of the quality path in the draft decision: The Commission's proposal to retain the current definition of "major interruption" and the proposal to define the term "gas leak" for the purposes of information disclosure.

Definition of major interruptions in the quality standard

We support the Commission's continued focus on ensuring reliable gas transmission services and acknowledges the intent behind the major interruptions quality standard. However, we continue to hold the view that the current definition of a "major interruption" has the potential to capture a wide range of scenarios, including small interruptions that only affect a single consumer for a short amount of time.

For the purposes of DPPs, the Commission's definition of a major interruption is:

> *"any declaration of a critical contingency caused or contributed to by an incident on the transmission assets owned or controlled by the GTB, which results in curtailment directions being issued in respect of curtailment band 2 and above"*[38]

If the interruption is on a main artery of the transmission system, like the Maui Pipeline, then many consumers will be affected. But if the interruption is just before a delivery point, then it will be only the consumers served by that delivery point that will be affected. At a small delivery point, there may only be a small number of commercial consumers to curtail under the Critical Contingency Regulations. The fact that the curtailment of a single commercial customer at a small delivery point would be treated as a breach of quality standards in the same way as an outage on the Maui pipeline highlights a lack of proportionality in how the major interruption standard applies across very different events.

This issue arises because the major interruption standard identifies when interruptions occur but does not have a reliable way of determining whether or not they are properly classified as 'major'.

When the major interruptions quality standard was first introduced at the 2017 DPP reset, the Commission acknowledged that not all breaches of that standard were equal and specifically listed the magnitude of the interruption as one of the factors that the Commission may take into account when considering an enforcement response.[39] Given the

[38] Section 4.2 of the Commission's *Gas Transmission Services Default Price-Quality Path Determination 2022*
[39] Commerce Commission, "Default price-quality paths for gas pipeline businesses from 1 October 2017: Final Reasons Paper," 31 May 2017, paras 7.59-7.60.

potential for the definition of major interruption to generate false positives, the Commission's documented intention to apply a proportionate approach to enforcement certainly makes sense.

We continue to believe that it would also be appropriate for the Commission to limit the circumstances when the quality standard applies to situations that meet an ordinary definition of "major". Accounting for the relative risks of interruption and customer impact is an important aspect of our own asset planning and this is important as we seek to avoid over-capitalisation in network assets (increasing the risk of future asset stranding). If the Commission were to instead adopt a rigid enforcement approach, we would be incentivised to make investments that reduce reliability risk but are excessively costly for the minor benefits.

We acknowledge that any changes to the major interruption standard would need to be carefully considered and consulted upon, which may not be possible in the current DPP process. On this basis, we accept the Commission's intention to retain the current standard, since any alternative measure would need to be carefully analysed and well justified. We would certainly welcome the opportunity to discuss with the Commission what options there might be for a more useful way to evaluate the reliability of the transmission system in the long-term interests of consumers.

Definition of a gas leak

In response to feedback it sought on the topic of gas leaks and whether a related quality standard might be warranted, the Commission concluded that "there is insufficient evidence to justify a quality standard at this time." We agree with the Commission's rationale and conclusion.

However, the Commission does intend to add a definition of gas leak to the input methodologies. The Commission has proposed to define a gas leak as "an escape of natural gas from gas infrastructure assets, which has the potential to cause an emergency, interruption or incident." We agree that this definition is reasonable and fit for purpose. We support the Commission's draft decision to formalise a definition of a gas leak within the input methodologies, as this provides clarity and consistency across gas pipeline businesses while aligning with current operational practice.

7) Conclusion and next steps

Our submission identified targeted changes that we consider would better reflect current and emerging conditions in New Zealand's gas sector. In particular, we support the Commission's continued focus on regulatory predictability and accelerated depreciation to manage asset stranding risk, while noting that recent developments strengthen the case for earlier and more comprehensive action. Our recommendations are directed at supporting ex-ante financial capital maintenance and ensuring that consumers are not exposed to avoidable price shocks as demand for gas pipeline services continues to decline.

Our recommendations are intended to enable prudent, efficient decision-making during a period of heightened uncertainty. Allowing timely recovery of capital, providing appropriate allowances for necessary step changes, and addressing known implementation issues within the existing framework will better align regulatory settings with the economic realities facing gas networks. We consider these changes to be consistent with the Part 4 purpose, in that they promote the long-term benefit of consumers by supporting network viability, smoothing the recovery of unavoidable costs, and reducing the risk of materially higher charges being imposed on a shrinking future customer base.

We appreciate the Commission's extensive engagement with stakeholders throughout the DPP4 reset process and the opportunity to comment on the draft decision. Firstgas looks forward to continuing to engage constructively with the Commission as it progresses toward the final determination, and we would welcome further discussion on any of the matters raised in this submission.

Yours sincerely

Saba Malik
Regulatory and Policy Manager
Firstgas

Appendices

The costs in this section are confidential and commercially sensitive – not for public release.

Appendix A – Cyber security for transmission and distribution

NZ$ (2027-2031)	Specified in AMP	Specified in Draft DPP decision	Funding Shortfall
Transmission	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Distribution	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

Cyber security is important for stakeholders, though the sensitive nature of the information makes it difficult to share widely with stakeholders

Below is a high-level description of what we have proposed and why.

We have also provided a comprehensive description in a separate, confidential appendix for the Commission's consideration. The comprehensive version sets out relevant background, our cyber strategy, our cyber security goals and our progress against the goals. It includes commercially and operationally sensitive information about our systems and cyber maturity. We have provided the Commission with an independent audit of the Firstgas corporate IT domain cyber security position and independent cost benchmarking.

We welcome feedback from the Commission and all stakeholders about how best we should be providing an appropriate level of public-facing assurance about our cyber security.

Our proposed increase in funding for cyber security is to sustain our current capability and deliver service enhancements to reach an appropriate maturity level

We seek approval for the full cyber security step change allowance to enable the uplift of our Operational Technology (OT) domain, while also sustaining our ongoing corporate Information Technology (IT) programme.

1. **Introduce new recurring opex for OT cyber security:**
   The step change is driven by the need to develop foundational cyber security capability across OT following completion of the Supervisory Control and Data Acquisition (SCADA) modernisation programme. Our legacy systems (especially SCADA) under DPP3 could not support modern security practices, and any controls we were able to apply were funded through capex. Ongoing development and support now require recurring opex. This uplift will follow the same structured

approach as corporate IT—frontloaded investment to implement controls, followed by enduring run costs for monitoring and assurance.

2. **Complete the ongoing corporate IT uplift programme:**
   Significant investment has already been made to improve our corporate IT security posture, achieving National Institute of Standards and Technology (NIST) Cyber Security Framework Tier 2.7 maturity. However, further investment is essential to reach Tier 3.0 within the next regulatory period.

This step change is supported by recognised industry standards, including the Australian Energy Sector Cyber Security Framework (AESCSF) and its Gas Criticality Assessment Tool, which set maturity expectations for high-criticality transmission and distribution networks. These frameworks align with NIST Tier 3 characteristics.

Our corporate cyber security costs are rising in line with industry benchmark increases

Our corporate IT domain supports both our gas transmission and distribution businesses. Independent benchmarking shows that corporate IT cyber security costs are increasing across comparable sectors, and we expect our own costs to rise in line with this trend, particularly as we continue to implement our cyber security uplift programme.

In regulatory year 2024 (RY24), Firstgas' corporate IT cyber security expenditure was in the second quartile relative to similar utility organisations. As we progressed our uplift programme and implemented the baseline capabilities expected of a prudent operator, our costs moved into the third quartile by RY26. This increase reflects targeted investment to address maturity gaps identified through independent audit. Cyber security expenditure in Firstgas' OT domains are concentrated within the gas transmission business.

Cyber security costs for Firstgas transmission business are attributable to securing real-time control systems, SCADA infrastructure, and field assets that require contemporary cyber protections. In contrast, the gas distribution business uses OT only for limited monitoring activities and therefore accounts for a small portion of overall OT cyber security spend.

Funding will reduce cyber security risks

Without this funding, Firstgas would remain below the maturity expected for a prudent operator, increasing operational, safety, and regulatory risk. Sustained investment is required because cyber risk is not static. Threats evolve continuously, and failure to act will degrade our position over time.

Full approval of the step-change allowance is essential for Firstgas to achieve and maintain NIST-aligned Tier 3.0+ maturity across both corporate IT and OT domains, meeting the Commission's expectations for prudent and efficient management of critical gas infrastructure. Importantly, this investment reduces the likelihood of consumer-level impacts such as supply interruptions, higher energy costs, and reduced reliability caused by cyber-related disruptions to gas transmission and distribution services.

Box 2 below highlights a real-world case study of cyber security event on a nationally significant energy infrastructure asset (Colonial Pipeline), reiterating our position on increased funding for cyber.

Box 2: Impact of a Major Cybersecurity Event – Colonial Pipeline Case Study

In May 2021, Colonial Pipeline, the largest refined-products pipeline system in the United States, operating a ~5,500-mile network, experienced a significant ransomware attack. Hackers gained access to Colonial's corporate IT environment via a compromised legacy VPN account that lacked multi-factor authentication (MFA). As a containment measure, the company shut down the full pipeline network for six days, halting fuel deliveries across the U.S. East Coast.

The operational outage had widespread economic and customer impacts:

- More than 12,000 petrol stations experienced fuel shortages, many running out of gasoline entirely.
- U.S. national average fuel prices rose to their highest level in over six years.
- Multiple U.S. states issued emergency declarations to support fuel distribution and maintain critical services.
- The federal government enacted extraordinary emergency measures including regulatory waivers and cross-agency coordination normally reserved for natural disasters, underscoring the systemic nature of the event.

Colonial Pipeline paid a US$4.4 million ransom, part of which was later recovered by the U.S. Department of Justice. Total remediation and recovery costs were estimated to be tens of millions of dollars, reflecting extensive system restoration, investigation activities, and cyber security uplift.

The International Energy Agency (IEA) assessed the outage as having a greater impact than the Suez Canal blockage that occurred the same year, highlighting the scale of consumer and supply-chain disruption. The incident also prompted congressional hearings and resulted in new mandatory cyber security directives for pipeline operators issued by the U.S. Transportation Security Administration (TSA).

Appendix B – Software-as-a-service (SaaS) Capability Improvement Allowance

The costs in this section are confidential and commercially sensitive – not for public release.

NZ$ (2027-2031)	Specified in AMP	Specified in Draft DPP decision	Funding Shortfall
Transmission	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Distribution	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

Overview of the funding request

We are modernising essential technology systems to ensure the safe, reliable, and efficient operation of our gas networks. Global vendors are shifting to cloud-first delivery models and signalling the long-term retirement of on-premise products, making continued investment in legacy infrastructure increasingly impractical and higher risk. Cloud-based SaaS platforms now represent the industry standard for supported, secure, and scalable business systems.

Our AMP outlines a staged transition to commercial off the shelf SaaS solutions across Data and Information Management, GIS and 3D imagery, Asset and Work Management, Health and Safety, and Field Workforce systems. These renewals replace existing capability and form part of routine technology lifecycle management—not expansion.

Changes to International Financial Reporting Interpretations Committee (IFRIC) guidance and New Zealand International Financial Reporting Standards (NZ IFRS) require SaaS based projects to be funded as opex rather than capex. This structural accounting change moves costs previously capitalised into recurring opex, creating a funding gap that cannot be met within existing allowances, even as we reduce our overall capex through DPP4.

Cloud based subscription models also provide a more stable and flexible cost profile than on-premise systems, which face increasing hardware, labour, cyber security, and support costs. SaaS enables expenditure to scale with our needs, reduces the risk of stranded IT assets, and ensures continued access to security updates and vendor innovation.

The requested SaaS capability allowance is essential to responsibly manage technology lifecycles, maintain compliance and security, and support safe and efficient service delivery throughout DPP4.

Background

Our AMP identifies a set of technology assets requiring lifecycle renewal or end-of-life mitigation over DPP4. Consistent with industry practice and our long-term technology strategy, these renewals will be delivered through a planned transition from on-premise systems to modern, supported cloud based platforms. Approval of the SaaS capability allowance is essential to fund these lifecycle replacements under updated accounting rules; without it, ageing systems would remain in service longer than is prudent, increasing operational, cyber, and compliance risk and limiting efficiency gains (risks and associated costs the consumer ultimately bears). The following tables outline the AMP defined technology renewal programmes and the consumer benefits enabled by replacing these assets with market standard SaaS solutions.

There are three trends that are relevant background for understanding the proposed expenditure:

1. Introduce new recurring opex due to mandated accounting changes for SaaS:

The step change is driven by the realised impact of the changes to International Financial Reporting Interpretations Committee (IFRIC) and New Zealand International Financial Reporting Standards (NZ IFRS) accounting standards, which now require cloud-based software projects including configuration, data migration, licensing, and support costs to be treated as operational expenditure rather than capital expenditure. Prior to 2021, the life-cycle renewal of our technology systems would have been fully funded by capex asset replacement projects.

While the Commission was aware of emerging IFRIC implications at the 2022 DPP3 reset, the full practical impact of these mandated accounting treatments was not yet quantifiable. The DPP3 final decision did not provide the SaaS allowances sought. Since then, IFRIC/NZ IFRS interpretations have been clarified and consistently applied, and global software vendors have accelerated the retirement of on-premise solutions, making cloud hosted solutions the most practicable pathway for lifecycle renewals.

We use market standard global commercial off the shelf (COTS) platforms, not bespoke developments and is not seeking investment for capability expansion. These renewals are part of normal technology asset lifecycle management required to keep systems secure, compliant, and supported. Under the revised accounting rules, even a modest like-for-like COTS cloud-based replacement requires opex funding.

There is a single funding pathway for each technology renewal. If we develop a bespoke system, the build component is funded through capex (with testing, data migration, and similar activities still required to be opex). If we replace the same functionality with a market-standard SaaS product, the entire renewal must be treated as opex under IFRIC and NZ IFRS. These treatments are mutually exclusive, ensuring the same renewal activity is only funded once.

2. Enable a prudent transition to cloud-based subscription models:

Across the utilities sector, modernising systems through cloud-based SaaS platforms is now considered standard practice. Industry frameworks such as the NIST Digital Modernization Principles, ISO/IEC 27001 (cloud security management), and the Australian Energy Sector Cyber Security Framework (AESCSF) all emphasise the need for supported, continuously updated platforms. SaaS models meet these expectations by providing secure systems without the technical debt and operational risk inherent in on-premise environments.

A growing number of Firstgas' technology systems are approaching the end of their supported life or are running on legacy on-premise hardware that cannot be virtualised or isolated without impacting operations. These legacy architectures are not able to support modern capabilities and functions like multi-factor authentication (MFA), increasing cyber security risk. Examples include:

- **Land, planning, and asset management systems**
  Legacy architectures with limited isolation increase security exposure and constrain modernisation, especially as these systems integrate with field mobility and customer-facing processes. Cloud migration supports secure, modern workflows.
- **Operational intelligence / OT historian**
  Legacy on-premise servers limit segmentation and security, increasing operational and cyber risk. A cloud-based historian can integrate safely with our Enterprise Asset Management System and modern data platform, enabling real-time monitoring and predictive maintenance.
- **Legacy enterprise data warehouse**
  Running on deprecated hardware, creating increasing failure and security risk. Moving to the cloud-native data platform removes hardware dependence and improves data quality, governance, and analytics.

Global software vendors, including Microsoft, Oracle, and IBM, are progressively retiring on-premise products, increasing licence charges, and shifting innovation exclusively to cloud ecosystems. While Firstgas' current systems remain supported today, support windows are tightening, and there is a credible and growing risk that key platforms will become unsupported or cost prohibitive to maintain during DPP4. Transitioning to SaaS ensures reliable access to security updates, vendor innovation, compliance with evolving cyber standards, and the capability uplift needed to safely manage gas infrastructure as the industry declines.

Cloud-based subscription models also provide flexibility that on-premise systems cannot: expenditure scales as user demand and asset volumes reduce, avoiding unnecessary bespoke capex investment in ageing infrastructure. This approach aligns with prudent asset lifecycle management principles.

Failing to fund this transition would leave us reliant on legacy on-premise technology with increasing cyber, operational, and compliance risk, limiting our ability to deliver prudent, efficient, and future ready technology services throughout DPP4; and ultimately forcing consumers to bear the large downside risk and associated cost.

3. All technology costs are rising faster and less predictably than CPI

Technology costs across the entire industry are increasing above CPI. Gartner validated data shows significant year-on-year price escalation for both software and cloud services, with renewal increases of 9–25% across major vendors. These cost pressures apply to on-premise and SaaS alike, and are further amplified in New Zealand by foreign exchange volatility for USD/EUR denominated products.

However, on-premise models are rising even faster and less predictably than SaaS due to hardware lifecycle costs, labour shortages, rising cyber security requirements, and the shrinking support windows for server based products. On-premise renewal cycles also create large, irregular capex spikes for hardware refreshes, data centre expansion, and major version upgrades.

SaaS provides a more stable and predictable approach under these conditions. Subscription models avoid large upgrade projects, reduce infrastructure and labour requirements, and ensure continuous access to supported, secure platforms. Cloud hosted services can also scale down with declining gas demand, avoiding the risk of stranded IT assets and overinvestment in ageing systems. Even with global price increases, SaaS remains the lowest risk and most future appropriate technology model for prudent operators during DPP4.

Operational intelligence, data platform and information management

Lifecycle renewal of data platforms and information systems to improve data quality, analytics capability, and operational efficiency.

Solution	Description	Improvement Programme	Consumer Benefits
Operational intelligence	Our OT historian is used as an on-premise operational technology platform to capture and store time-series data from SCADA and other control systems. It supports real-time and historical signal analysis, enabling predictive maintenance, and performance monitoring.	The historian platform operational intelligence will integrate SCADA data into the corporate network to enable real-time and historical signal analysis, predictive maintenance, and enhanced reporting across systems like Maximo and Microsoft Fabric Modern Data Platform. If funded, we expect to implement this in FY27-FY28.	• Safety first: Real-time monitoring and predictive maintenance reduce risks as infrastructure ages. • Lower outage risk: Proactive fault detection prevents costly disruptions. • Efficient end-of-life management: Avoids unnecessary investment in legacy systems nearing obsolescence.

Data platform management	We are operating both our legacy on-premise data warehouses and modern data platform. Our modern data platform is a cloud-native, scalable, integrated platform that collects, stores, processes, analyses, and governs data efficiently. It will enable the ability to support real-time insights, AI, and advanced analytics. We have designed a comprehensive data governance framework, completed a modern data platform proof of value, and began a multi-year data programme to implement our modern data platform, replacing the legacy enterprise data warehouses with a cloud-native solution.	The process to ingest, transform, and promote data products for improved business insights with our data governance framework will continue to progress FY26-FY29. Investment in data quality, governance, and availability (of data, analytics and insight to more of our people) is a strategic factor required for the efficient and effective management of the AMP.	• Smarter decisions: Accurate data helps optimise maintenance and avoid over-investment in declining assets. • Cost control: Cloud solution costs scale with our demand, which is especially valuable in a future with reduced operations. Cloud solutions also allow us to eliminate sources of legacy IT costs (physical servers, storage, network hardware). • Future adaptability: Supports transition planning for alternative energy or decommissioning.
Information management	Information management supports the ability to store, access, and protect critical documents and data. With the introduction of AI tools, we require the need to invest in our information management governance.	Over FY26-FY27 we will consider document storage options, additional information governance controls, and cyber security to protect against unauthorised access. This will allow us to be more confident in our generative AI interactions and have privacy assurances for	• Secure handling of sensitive data: Protects consumer and operational information during industry transition. • Confidence in AI tools: Ensures safe adoption of technology without compromising privacy. • Reliable access: Supports continuity

		interacting with sensitive information.	of service even as systems consolidate.

GIS 3D Imagery Storage

Ongoing server upgrades and storage expansion for LiDAR and imagery, with a planned cloud-hosting transition. Supports compliance-driven mobile asset inspection and desktop analysis.

Solution	Description	Improvement Programme	Consumer Benefits
Geographic information system (GIS)	GIS is the master spatial register for pipeline assets across the Firstgas networks. It integrates geospatial, technical, connectivity, and land management and asset data which cross references with the enterprise asset management solution.	Server upgrades and additional storage for LiDAR and imagery (UAV and manned aircraft) planned for FY26 and is expected to grow. This will enable desktop analysis reducing the need for site visits which will lower operating costs and minimise health and safety risk. We are currently implementing the utility network framework over FY25-FY26, which will enable rule-based connectivity and attribute modelling improving data integrity. We are also migrating and updating our GIS SQL servers in our data centre. Upgrading our application development toolset in RY26 as an application lifecycle maintenance and improved user experience. If funded, ongoing planning for a	• Improved asset inspection: High-resolution LiDAR and imagery allow accurate pipeline condition monitoring without extensive fieldwork. • Reduced health and safety risk: Fewer site visits lower exposure to hazards for workers, ensuring safer operations. • Lower operating costs: Desktop analysis reduces travel and labour costs, helping keep consumer charges stable. • Scalable investment: Cloud transition ensures storage and processing capacity can adjust as network size and demand decline. • Faster issue detection: Enhanced imagery supports quicker identification of potential faults or land-use risks. • Better planning: Accurate geospatial data improves maintenance scheduling

		cloud transition will progress FY27-FY29.	and reduces the likelihood of service disruptions.

Asset and Work Management

Modernising systems that support asset lifecycle planning, maintenance execution, land parcel ownership, and field operations.

Solution	Description	Improvement Programme	Consumer Benefits
Land and planning management	Our existing land and planning solution (an on-premise solution) manages landowner information and easement permit data, support pipeline location responses, and integrates field data from unauthorised activities and permits.	Users of the system are currently reviewing the functionality and data quality. More investigation is required before determining the replacement or cloud transition approach which is expected to be defined in FY27.	• Improved compliance with land access and safety obligations • Reduced delays in approvals • Lower operating costs through streamlined processes • Better planning for decommissioning in a declining industry.
Enterprise asset management	Our asset management platform supports lifecycle asset planning, maintenance execution, and service delivery. The tooling is integrated with GIS, corporate financials, and our data platform.	We are currently re-implementing our enterprise asset management solution, correcting legacy data structure issues and configuration conflicts to be complete in FY25-FY26. The new solution enables accurate data capture at source, integrates with field mobility tools to improve operational efficiency, regulatory compliance, and decision-making. Once the new cloud-based system is embedded we will continue to invest in the	• Fewer service disruptions through proactive maintenance • Faster repairs with mobile tools • Cost efficiency via automation • Enhanced safety and compliance • Future-ready for transition and end-of-life planning.

		platform to gain better insights about our assets and streamline management process through introducing mobile field applications, process automation, predictive analytics, and leverage AI capabilities to support remote data-driven decisions over FY26-FY29.	

Health and Safety Management

Upgrading health and safety systems and processes to improve incident management, reporting accuracy, and compliance.

Solution	Description	Improvement Programme	Consumer Benefits
Health and safety management	Incidents related to network assets and customer complaints (non-staff related) are recorded, managed, and reported via the Maximo enterprise asset management system. Workplace related incidents and injuries are managed via manual processes and registers.	Planning to complete a health and safety capability map in FY26 to enable the assessment of suitable tooling for recording, managing, and reporting workplace related incidents and injuries.	• Safer network operations through improved incident tracking • Faster resolution of safety issues • Greater confidence in compliance with health and safety standards • Reduced risk for consumers and workers.

SaaS Financial Analysis DPP3

To demonstrate the financial impact of changes in accounting treatment and the shift to SaaS delivery models, this analysis presents total technology project expenditure across recent financial years, showing the allocation between Capex and Opex. Total project spend has been used to enable a consistent, like-for-like comparison across years, reflecting how technology delivery models and associated accounting treatment have evolved over time. While individual projects vary in nature, the aggregate view in **Table 1** illustrates a clear structural shift in funding, with a growing proportion of technology investment now required to be expensed as Opex rather than capitalised as Capex.

Table 1: Technology Project Spend RY21-RY25 ($000 NZD)

Financial Year	Total Spend	Capex (%)	Opex (%)
RY21	**[REDACTED]**	**50%**	**50%**
RY22	**[REDACTED]**	**27%**	**73%**
RY23	**[REDACTED]**	**13%**	**87%**
RY24	**[REDACTED]**	**9%**	**91%**
RY25	**[REDACTED]**	**28%**	**72%**

The higher capex proportion in RY25 reflects a one-off development phase of a legacy system migration where custom code development and integration was still treated as capex. These projects required Firstgas to retain intellectual property associated with bespoke build and integration components, which under accounting rules qualifies as capex. However, all other associated delivery costs, such as SaaS configuration, discovery, planning, testing, and training are required to be expensed as opex. As SaaS-based delivery models mature, these legacy capex components disappear, resulting in a structurally higher opex share in subsequent years.

Forecasting

The following forecast outlines the expected opex associated with a subset of the planned SaaS lifecycle renewals across RY27–RY31. These programmes are drawn directly from the AMP and represent the prudent and efficient transition of critical technology assets from on-premise systems to modern, supported SaaS platforms. The forecast illustrates the long-term funding required to maintain secure, reliable, and compliant systems, and reflects the shift from capex to opex accounting treatment for cloud-based solutions.

The forecast tables below present the total expected opex associated with planned SaaS lifecycle projects, reflecting the full cost of delivery across each project's implementation and operational phases. These totals represent the aggregate project costs. The DPP4 step change funding request for the RY27-RY31 period represents only a portion of these total costs, specifically the incremental funding required above existing allowances to enable delivery of these projects within the DPP4 window. Accordingly, the step change amounts are materially lower than the project costs shown in the tables and should be interpreted as the additional funding component, rather than the full cost of the projects.

Table 2: Subset of Firstgas Transmission SaaS Projects RY27-RY31 ($000 NZD)

Project	RY27	RY28	RY29	RY30	RY31
Data, Information, and File-share Management	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
GIS 3D Imagery Storage (e.g. LiDAR)	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Asset and Work Management	**-**	**-**	**-**	**[REDACTED]**	**[REDACTED]**
Health and Safety Management	**-**	**[REDACTED]**	**[REDACTED]**	**-**	**-**
Field Workforce Management	**-**	**-**	**-**	**-**	**[REDACTED]**
Total	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

Table 3: Firstgas Distribution SaaS Projects RY27-RY31 ($000 NZD)

Project	RY27	RY28	RY29	RY30	RY31
Data, Information, and File-share Management	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
GIS 3D Imagery Storage (e.g. LiDAR)	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**
Asset and Work Management	**-**	**-**	**-**	**[REDACTED]**	**[REDACTED]**
Health and Safety Management	**-**	**[REDACTED]**	**[REDACTED]**	**-**	**-**
Field Workforce Management	**-**	**-**	**-**	**-**	**[REDACTED]**
Total	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

Commercial price increases

The table below presents examples of commercial opex services where year-on-year cost movements have been analysed to distinguish underlying price changes from general inflationary effects. Prior-year expenditure has been indexed for CPI to establish an inflation-adjusted benchmark, enabling assessment of observed commercial price movements.

Table 4: Example of Technology Commercial Price Increases (%)

	Nominal YoY Increase		Real Increase (above CPI)	
Description	**RY24**	**RY25**	**RY24**	**RY25**
Application Support	**7%**	**4%**	**5%**	**1%**
Workflow Automation Tool	**5%**	**5%**	**3%**	**2%**
Enterprise Integration Platform	**-**	**7%**	**-**	**4%**
Scheduling and work planning tool	**5%**	**10%**	**3%**	**7%**

CPI Source: Stats NZ, Consumers Price Index (CPI), September 2024 and September 2025 quarters

Prudence and Efficiency Measures

We apply a disciplined lifecycle management, maximises existing investments, and adopts market-standard commercial-off-the-shelf solutions to ensure prudent and efficient technology delivery. We leverage vendor best practices, avoid bespoke development, and use structured programme governance to manage cost and delivery risk.

SaaS subscription models further support prudent expenditure by replacing large, irregular on-premise capex cycles with predictable opex, reducing technical debt, ensuring continuous access to secure, supported platforms, and allowing costs to scale with declining gas demand. This approach aligns with industry standards and represents the most efficient long-term model for maintaining safe, reliable, and compliant technology services.

Appendix C – Legal resource for urbanisation for Firstgas transmission

The information in this table is confidential and commercially sensitive – not for public release.

Current developments adjacent to our pipeline

Development	Pipeline	Development Type	Pipeline protections
[REDACTED]	200	Urban development - Residential	Pipeline protection works.
[REDACTED]	410/402	Urban development. **[REDACTED]** Mixed use residential/commercial multi lot development with an element of high density	Pipeline realignment and development of easement rights.
[REDACTED]	400 200 402	Urban development. Large lot lifestyle residential and commercial lots. Construct taxiways over pipelines and utilities infrastructure.	Pipeline protection works and easement rights.
[REDACTED]	400B	Urban development – Residential	Pipeline realignment
[REDACTED]	200	Urban development - Residential Construction of a new road over pipeline.	Pipeline realignment.
[REDACTED]	430, 060	**[REDACTED]**	**[REDACTED]**
[REDACTED]	200	**[REDACTED]**	Pipeline protection works and/or realignment.
[REDACTED]	200	Urban development - Residential	Pipeline protection works.
[REDACTED]	100	Retirement village	Pipeline protection works.
[REDACTED]	200	Urban development - Residential	Pipeline protection works.
[REDACTED]	400B	Urban development - Residential	Pipeline protection works.
[REDACTED]	400B	Multi lot light to medium industrial development	Awaiting further details from the developer. Protections likely necessary.
[REDACTED]	200	State highway upgrades	Construct new road infrastructure over 200 pipeline (to facilitate slip lanes and access into the new train station). Pipeline realignment.
[REDACTED]	400B	Large urban development **[REDACTED]**	**[REDACTED]** Pipeline protection works and/or realignments expected to be necessary.

Development	Pipeline	Development Type	Pipeline protections
[REDACTED]	430	**[REDACTED]**	There are multiple points with the pipeline along the preferred route with pipeline protection works likely. **[REDACTED]**
[REDACTED]	200	Urban development - Residential	Pipeline protection works
[REDACTED]	400B	Industrial development **[REDACTED]**	Pipeline protection works

Appendix D – Non-recurring cost savings

The information in this table is confidential and commercially sensitive – not for public release

As discussed in section 3 of this paper, it is essential to adjust the base year for non-recurring savings in the same way as non-recurring expenses because both distort the efficient cost baseline. If non-recurring savings are left unadjusted, they are wrongly treated as unstainable efficiencies and when embedded into long term allowances understate future requirements. Failing to adjust base year for savings will introduce downward bias and would undermine accuracy and fairness in regulatory settings.

During RY25 we made some non-recurring opex savings (cost reductions) which we do not expect to make during DPP4 period. Further information on these one-off cost reductions is provided below.

Senior management position vacant for a year

The Chief Financial Officer's position was vacant during 2025. That created a one-off non-recurring saving cost saving and resulted in lower opex levels for 2025 which the Commission will use as the base year for setting opex allowances. Once this role is filled, the associated cost becomes ongoing.

If the opex allowance is not adjusted for this temporary saving, it will create an inefficiency for the business and also a downward bias in opex allowances.

Based on our approach to executive remuneration, we have used Strategic Pay data for benchmarking. The appropriate range for the role is as follows:

Title	80% of midpoint	Midpoint	120% of midpoint
CFO	**[REDACTED]**	**[REDACTED]**	**[REDACTED]**

We recommend that opex base year cost is adjusted to reflect the midpoint salary saving.

SaaS cost savings

We observed **[REDACTED]** savings in Saas opex cost due to a single large project cost capitalisation. This resulted in lower opex levels in relation to SaaS spend in RY25.

This was driven by a legacy system project where a significant portion of the technical effort was capitalised. Because the project involved bespoke development and integration work, Firstgas retained the associated intellectual property, which qualified that component of spend as capex under accounting rules.

This capex treatment temporarily suppressed the opex profile for the year by shifting what would normally be recurring SaaS project activities, such as configuration, discovery, planning, testing, and deployment, out of opex and into capital spend. As a result, RY25 does not reflect the true steady-state SaaS cost base, and the apparent opex reduction is not a sustainable saving.

As our technology stack transitions fully to cloud-based hosted delivery models, these legacy capitalisable development efforts will no longer exist. All future SaaS-related project work will be required to be treated as operational expenditure, reinforcing the structural uplift presented in the step-change request.

We recommend that opex base year cost is adjusted to reflect this one-off saving so that our opex allowances are free from downward bias and adequately reflect the required level of spending during DPP4.

Appendix E – Deloitte's report on non-fixed-life easements

This report has been provided separately.