Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital relating to the gas sector

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Prepared for Firstgas, Powerco and Vector

19 July 2023

Contents

Executive summary

The New Zealand Commerce Commission (NZCC) has recently published its draft decision (DD) to the Part 4 Input Methodologies (IMs). This includes its preliminary decisions in relation to the weighted average cost of capital (WACC) and the WACC percentile that is chosen for Gas Pipeline Businesses (GPBs).[1] This report, which has been commissioned by the three Gas Distribution Businesses (GDBs) Firstgas, Powerco and Vector, analyses the WACC issues that are particularly relevant to the gas sector. Some of these—in particular the proposals around the removal of the WACC uplift for GPBs—are wide-ranging changes that did not involve prior consultation, conferring a relatively limited window for industry to respond within five weeks.

In the context of the energy transition and New Zealand's legislative commitment to achieving net zero by 2050, there is significant uncertainty about the shape of the transition, and therefore about the level of future gas demand, as well as the pace of change in demand. This uncertainty affects a number of regulatory parameters, including the WACC (especially via the asset beta and debt premium), the WACC uplift and uncertainty mechanisms used by the regulator. These measures are all interrelated. For instance, there is less need for a WACC uplift if there is less risk of regulators having underestimated the parameters within the WACC calculation, or having left networks exposed to risks that are not remunerated elsewhere within the price control. Our analysis finds that the removal of the WACC uplift for GPBs risks setting a regulated WACC that is too low, which could result in underinvestment and thereby significant costs. The NZCC might not have fully taken these costs into account.

WACC

We assess the WACC parameters that are common across gas and electricity in a separate report commissioned by the Electricity

[1] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).

Distribution Businesses (EDBs),[2] while focusing in this report on the aspects of the WACC allowance affected by gas-specific risks.

While the NZCC provides a 0.05 uplift to the asset beta allowance for GPBs, we find that the NZCC's own evidence supports a higher estimate.

Evidence from credit rating agencies, and on bond premia, for gas compared to electricity networks suggests that GPBs face higher risks than EDBs given the uncertain outlook for the gas sector. Therefore, we consider that an uplift to the debt premium for GPBs, relative to the debt premium that the NZCC has calibrated across the industry, would be justified.

WACC percentile

The NZCC's draft proposal is to remove the WACC uplift for GPBs. The reasons for this are that the NZCC considers the cost of electricity outages to be higher than that of gas outages, and the likelihood that underinvestment will go undetected and lead to outages to be lower for gas. However, we consider that there is sufficient evidence to warrant a WACC uplift (in line with EDBs) for a number of reasons.

First, the previous decision to set the WACC at the 67th percentile appears to have resulted in good outcomes for consumers. That is, there is no evidence of gas networks having earned excessive profits and, simultaneously, network quality measures have improved over time. Deviating from regulatory precedent on this topic risks creating under-investment incentives. Moreover, we agree that the reliability metrics used by the NZCC show that gas networks exhibit significantly higher reliability than electricity networks. However, removing the WACC uplift for GPBs based on this appears to 'punish' networks for good performance, which could lead to unintended consequences.

Additionally, there are significant costs associated with gas outages that have not been examined by the NZCC as part of its considerations, in relation to reducing the WACC percentile for GPBs in the DD. These costs arise mainly due to industrial users that rely on steady gas supply. The NZCC—in its qualitative reasoning regarding the outage cost of

[2] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital. Prepared for the New Zealand electricity distribution businesses', 19 July.

gas—appears to focus on domestic usage, which only accounts for 6%[3] of gas demand in New Zealand. The cost of a major outage in New Zealand has been estimated at NZ$200m in 2012, which corresponds to around NZ$266m in 2022 prices[4]—predominantly due to industrial users. We note that this estimate is based on an incident that was caused by a landslide, rather than underinvestment per se. However, we understand from discussion with the GPBs that gas networks are investing in climate risk mitigation for their assets, and a WACC that is set too low could result in networks reducing such investments where there is discretion in relation to the level and types of expenditure.

While outage costs in the gas sector are indeed lower than in the electricity sector, there is also a much lower RAB for GPBs (NZ$2.1bn compared with NZ$18.4bn for electricity networks). This is relevant in the context of the NZCC's loss analysis framework, which weighs the costs of two opposing effects:

- the costs associated with a given WACC percentile (i.e. the impact on consumers measured by RABxWACC)—the higher the WACC percentile, the higher these costs will be;
- the cost of outages that might occur if there is underinvestment, with underinvestment occurring when the regulated WACC at a given percentile is below the true WACC— the higher the WACC percentile, the lower the probability (and therefore the expected cost) will be.

When calibrating the NZCC's loss analysis framework for the lower RAB of GPBs, the model finds that at an outage cost of NZ$110m (and when removing the tax uplift), the average optimal WACC percentile would be at the 67th percentile, in line with the previous NZCC decision.[5] This outage cost is less than half of the estimated gross cost from the Maui pipeline incident in 2022 prices. While we note that this analytical framework has limitations—in particular because it does not explicitly take into account the frequency and duration of outages—the numbers

[3] Calculated based on annual petajoule (PJ) data from and excluding 'non-energy use' of gas using data from New Zealand Ministry of Business, Innovation & Employment (2023), 'Data tables for gas', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/ (accessed 5 July 2023).
[4] Using a GDP deflator from the World Bank to inflate prices from 2012 to 2022. The World Bank, 'GDP deflator: New Zealand', https://data.worldbank.org/indicator/NY.GDP.DEFL.ZS.AD?locations=NZ (accessed 17 July 2023).
[5] This is the average when removing the tax uplift and taking an average of the percentiles at a threshold for underinvestment of 0.5% and 1%. We found the evidence supported retaining the 67th percentile in Oxera (2023), 'Asset beta and WACC percentile for New Zealand gas distribution businesses'; 1 February.

are nevertheless a helpful indication for the purpose of setting the WACC percentile within the NZCC's loss analysis approach.

Finally, outages are not the only potential downside of underinvestment in gas networks. We find and, where possible, indicatively quantify the magnitude of the following additional costs that may occur as a result of underinvestment.

- Increased leakage and gas escapes, leading to environmental costs associated with the released methane into the atmosphere: using shadow prices of carbon, we find that the cost that has been saved by reducing leakage between 2013 and 2022 amounts to around NZ$31m.[6] This shows the importance of continuing to ensure investment incentives for leakage prevention are in place to minimise such environmental costs to society.
- Decarbonisation costs of delaying the transition to renewable gases: while we recognise that there is significant uncertainty over the extent of renewable gas usage and the proportion of this that may be transported via gas pipeline infrastructure, we find that even relatively short delays that might occur as a result of underinvestment can result in high costs for consumers. For instance, our illustrative calculation of the difference in net present value of saved emissions between following New Zealand's hydrogen strategy and delaying it by two years shows the cost of this delay to be between NZ$57m and NZ$114m.
- Preventing an orderly transition: we note that a successful transition to a low-carbon system requires a coordinated approach among different parties. If GPBs were to underinvest, then this could lead to parts of the network being shut off prematurely. This in turn could leave businesses without a reliable energy source, or poor network quality, if alternatives are not yet available, or the electricity network does not yet have sufficient capacity.

These costs are additional to any outage costs that are being considered as part of the loss analysis framework. Overall, this analysis suggests that there can be significant costs if gas networks were to

[6] This is calculated using leakage data published as part of the GPBs' disclosure data and converting it to CO_2e emissions using the average emissions per leak/escape based on data from Firstgas. We then value the difference in emissions between 2013 and 2022 at 2022 carbon prices (using the central shadow price of carbon sourced from New Zealand Treasury (2022), 'Information on the shadow price of carbon (OIA-20210278)', 5 April, https://www.treasury.govt.nz/sites/default/files/2022-03/oia-20210278.pdf (accessed 7 July 2023).

underinvest. Using a percentile above the 50th reduces the risk that the true WACC is below the regulated one, and therefore the risk of underinvestment.

Other regulatory tools

Our analysis of incentives and uncertainty mechanisms within the regulatory framework in New Zealand suggests that these may not be sufficient to counteract the asymmetry of risks and costs resulting from setting the WACC at the mid-point. Therefore, we consider that a WACC uplift for GPBs in line with the previously used 67th percentile continues to be an appropriate tool to address this asymmetry, and should be retained.

1 Introduction

1.1 On 14 June 2023 the New Zealand Commerce Commission (NZCC) published its draft decision (DD) to the Input Methodologies (IM). This report, on behalf of the gas distribution businesses (GDBs) FirstGas, PowerCo and Vector, responds to the NZCC's cost of capital topic paper, which was published as part of the DD.[7]

1.2 A number of issues in relation to the weighted average cost of capital (WACC) apply to both electricity and gas networks. This report therefore summarises our findings on the common WACC issues, and references a report we have prepared on behalf of the electricity distribution businesses (EDBs) for more detail on the analysis.[8]

1.3 This report focuses on a number of gas-specific topics in relation to the WACC, as well as the WACC percentile and other regulatory tools. These are all interlinked. For instance, there is less need for a WACC uplift if there is less risk of regulators having underestimated the parameters within the WACC calculation, or having left networks exposed to risks that are not remunerated elsewhere within the price control. Similarly, other regulatory mechanisms, such as quality incentive schemes or uncertainty mechanisms, can be used to reduce the risk of underinvestment (thereby reducing the need for a WACC uplift to compensate for risks that are under-funded). If the WACC calculation and the regulatory incentive package do not sufficiently reduce the risk of underinvestment then a higher WACC percentile than the 50th percentile is likely to be optimal.

1.4 The structure of the report is as follows.

- Section 2 discusses specific parts of the WACC allowance for gas networks, namely the asset beta and the debt

[7] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).
[8] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital. Prepared for the New Zealand electricity distribution businesses', 19 July.

premium. It also summarises our findings on WACC parameters that are common across gas and electricity.

- Section 3 covers the WACC percentile, which had previously been set at the 67th percentile, with the NZCC suggesting in its latest DD to reduce it to the 50th percentile for Gas Pipeline Businesses (GPBs).[9]
- Section 4 sets out other regulatory instruments to address risks relating to underinvestment—including those used by the NZCC and by regulators in other jurisdictions.

[9] GPBs include the distribution companies (GDBs), as well as the gas transmission company.

2 WACC

2.1 In a separate report for EDBs,[10] we have assessed selected aspects of the WACC allowance estimation that are common across the gas and electricity sectors. These include issues relating to:

- the risk-free rate (RFR);
- the debt premium and term credit spread difference (TCSD);
- the tax-adjusted market risk premium (TAMRP),
- asset beta;
- WACC allowance reasonableness checks;
- financeability and equity issuance allowance.

2.2 In this report, we focus on the aspects of the WACC allowance estimation that may vary across the sectors, as they can reflect sector-specific risks. These are the asset beta and debt premium allowances.

2.3 The rest of this section is structured as follows:

- in section 2A, we summarise our findings in relation to the WACC parameters that are common across the gas and electricity sectors;
- in section 2B, we discuss the uplift to GPBs' asset beta;
- in section 2C, we assess whether a higher debt premium is justified for GPBs.

2.4 We also replicate the TAMRP section from the EDBs report in Appendix A1. The details of our assessment of parameters that are common across the gas and electricity sectors can be found in our report for EDBs.[11]

[10] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital. Prepared for the New Zealand electricity distribution businesses', 19 July.
[11] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital. Prepared for the New Zealand electricity distribution businesses', 19 July.

2A Summary of the findings for WACC parameters that are common across the gas and electricity sectors

2A.1 Risk-free rate

2.5 We have assessed the following aspects of the NZCC's IMs related that relate to setting the RFR allowance.

- **Adding a convenience yield premium to government bond yields.** We have assessed Dr Lally's dismissal of the academic evidence, based on which the NZCC has provisionally decided not to add a convenience yield premium to the government bond yields when estimating the RFR, and shown that the theoretical case for the convenience yield remains strong.[12] A convenience yield of any magnitude would imply a higher RFR allowance.
- **The term of the government bonds used to estimate the RFR.** We have reviewed Dr Lally's modelling and concluded that it does not prove that the term has to match the length of the regulatory period. We recommend considering longer tenors, such as five to 20 years.

2A.2 Debt premium and term credit spread difference

2.6 Among the topics relating to the cost of debt allowance, we have assessed the case for the trailing average approach to the debt premium and the level of the TCSD.

- **The trailing average approach to the debt premium.** Based on Dr Lally's assessment, the NZCC has provisionally decided not to introduce any mechanisms that address the uncertainty in relation to the level of credit spreads that networks face during the regulatory period. We have evaluated Dr Lally's assessment and found that bringing the assumptions of his modelling more into line with market conditions makes the case for the trailing average significantly stronger. We also note that the trailing average is not the only approach that could be used to address the credit spread uncertainty faced by the networks.
- **The term credit spread differential.** We find that the NZCC's own evidence supports a higher TCSD at **10.2bps** instead of **7.5bps** if the NZCC does not subjectively exclude

[12] See Dr Lally's advice at Lally, M. (2023), 'Review of submissions on the risk-free rate and the cost of debt', 17 March.

the COVID-19 period from the estimation window, and if it avoids double-counting a category of the bonds within its sample. In addition, we do not find the ten-year term cap to be well justified.

2A.3 Tax-adjusted market risk premium

2.7 We have assessed the evidence that the NZCC relied on when it concluded on the TAMRP level of 7.0%, and found that some of it is not sufficiently reliable.

- **Dividend growth model (DGM) and survey data.** We have undertaken modelling that demonstrates why we do not find DGM to be a robust approach to estimating the TAMRP. We have also previously explained the limitations of using survey-based evidence to assess the reasonable level of the TAMRP.[13] Therefore, we recommend that the NZCC does not put weight on the results from the DGM, and the survey-based results, in its estimation of the TAMRP.
- **The Siegel models.** We recommend placing more weight on the evidence from the Siegel II model and less on the evidence from the Siegel I model, due to the former's more reliable assumptions about the relationship between the RFR and the MRP. This means that a more reliable TAMRP estimate would be anchored on the evidence from the Ibbotson model and a weighted Siegel model that reduces reliance on the Siegel I specification.
- **Broker estimates.** Based on the evidence that we have collated from the public domain, we have found that the TAMRP estimates by investment banks selected by the NZCC do not fully represent the view of these institutions. As a result, the data relied upon by the NZCC does not appear to be robust.

2.8 The more robust estimation methodologies that underpin the TAMRP range point to an estimate that is closer to **7.5%** than to the **7.0%** proposed by the NZCC. The figure of 7.5% is also consistent with the broker estimates that we have collected.

[13] For more details, see Oxera (2023), 'Review of the NZCC's WACC-setting methodology', 31 January, p. 27.

2A.4 Asset beta

2.9 In our report for EDBs, we comment on two aspects of the NZCC's asset beta estimation, as follows.

- **Frequency of returns data.** We recommend that the NZCC adds daily beta estimates to the set of evidence that it uses to set the allowed asset beta. The key concern typically associated with daily beta estimates is stock illiquidity, which is mitigated in this instance given that the NZCC applies liquidity filters. We also show that the average standard errors of individual comparators' asset betas are the lowest for daily asset betas, which shows that from the point of view of statistical significance, there is no reason to exclude daily betas from the NZCC's assessment.
- **Treatment of the COVID-19 period.** We consider that the beta estimates affected by the COVID-19 pandemic provide valuable information about the companies' risks, in the same way as any other event causing market volatility would. Accordingly, we see no reason for the COVID-19 pandemic period to be treated differently (from, for example, the period of the global financial crisis) and for it to lead to the change in the NZCC's approach as part of this IMs review. We find the NZCC's approach concerning, as it introduces non-justified non-replicable methodological steps and, in so doing, deviates from the NZCC's principles-based approach and reduces the stability and predictability of the regulatory regime.

2.10 Compared with the NZCC's preferred asset beta estimate of **0.35** for energy networks, an average of daily, weekly and four-weekly estimates for the last two five-year periods is **0.37**, while the 75th percentile of the range (which is consistent with the percentile that the NZCC chooses for asset betas in its DD within its proposed range) of these estimates is **0.39**.

2A.5 WACC allowance reasonableness checks

2.11 In terms of the reasonableness checks, we assess the NZCC's check using RAB multiples and propose an alternative one.

- **RAB multiples.** In this report, we explain that many factors need to be accounted for when interpreting RAB multiples, and that conclusions are sensitive to the assumptions. Therefore, we do not consider RAB multiples to be a reliable check of the reasonableness of the WACC allowance.

- **Asset risk premium–debt risk premium (ARP–DRP) framework.** We introduce an alternative approach of cross-checking the cost of equity allowance with reference to the cost of debt estimate. The cross-check shows that the risk premium, embedded in the cost of equity, if adjusted for the effect of leverage (ARP), is not sufficiently high relative to the DRP, which suggests that the overall allowance for the cost of equity should be higher.

2A.6 Financeability and equity issuance costs

2.12 Finally, we consider financeability and equity issuance costs.

- **Financeability.** We explain that financeability is affected by the cost of capital allowance. We find that it would be practical for the NZCC either to undertake a provisional financeability assessment at the IMs review stage, when the methodologies for the cost of capital allowance are set, or to specify the financeability test principles in the IMs and carry out the test when setting default price–quality paths (DPPs), customised price–quality paths (CPPs) or individual price–quality paths (IPPs). As for the form of the test, in addition to the NZCC's present focus on actual networks' financeability, the NZCC could assess the financeability of a benchmark (efficiently run) company.
- **Equity issuance costs.** We explain that retained profits may not always be sufficient to finance growth, while not paying dividends for a long period of time is not sustainable, and at times new equity financing may be needed and the allowance for equity issuance costs would be justified. An allowance for equity issuance costs, combined with a regulatory assumption that dividend payments will be made, is aligned with regulatory precedent in other jurisdictions. Practically, financial modelling required for the financeability test would show whether networks need to issue equity within the price control period, to finance their investment programmes.

2B Asset beta for gas

2.13 While not assessing the asset beta based on gas and electricity samples separately,[14] the NZCC provides a 0.05 uplift to GPBs'

[14] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, para. 4.141,

asset beta recognising that they are exposed to a higher level of systematic risk.[15] In particular, the NZCC assesses that the higher income elasticity in the gas sector than in the electricity sector, and a lower gas connections penetration rate in New Zealand than overseas, imply an overall higher risk for New Zealand GPBs.[16]

2.14 The NZCC makes the following observations when setting the 0.05 uplift.

- The NZCC notes that the asset beta estimated exclusively based on the gas networks' sub-sample is 0.47, i.e. **0.12** higher than the 0.35 asset beta that the NZCC is proposing for energy networks in general (and that is estimated based on the wider sample of energy networks).[17]
- The NZCC further observes that the gas-sample beta estimate is sensitive to the inclusion of one gas company, ONEOK Inc., and without that company, the gas-sample beta is 0.43—i.e. **0.08** higher than the proposed beta for energy companies.[18]

2.15 These estimates are closer to the 0.1 that the NZCC applied in the 2010 IMs, than to the 0.05 uplift that the NZCC applied in the 2016 IMs and proposed for the 2023 IMs.[19]

2.16 We do not find the NZCC's evidence supportive of an uplift of 0.05, as both estimates of the differences between gas-specific and energy asset betas that the NZCC considers are higher than 0.05.

2.17 Therefore, we find the NZCC's considerations inconsistent, and consider that the evidence it provides supports an uplift that is closer to 0.1 rather than 0.05.

2C Debt premium for gas

2.18 As discussed above, the NZCC considers that New Zealand GPBs face greater demand risks than EDBs, given the low penetration

https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).
[15] Ibid., para. 4.155.
[16] Ibid., para. 4150.
[17] Ibid., para. 4.151.
[18] Ibid., para. 4.152.
[19] New Zealand Commerce Commission (2016), 'Input methodologies review decisions; Topic paper 4: Cost of capital issues', 20 December, para. 349.

of gas connections and high income elasticity. In this section, we assess whether, keeping other things equal, the decarbonisation agenda and the associated uncertainty lead to the greater credit risk of gas networks, compared to electricity, and GPBs require an uplift on the debt premium.

2.19 Indeed, the NZCC has recognised the uncertainty in the long-term outlook for the gas industry in its reference to RAB multiples: 'Jarden's estimate of a RAB multiple of 1.00 for Vector's gas assets reflects uncertainty around the long-term outlook for the sector and the regulatory settings leading up to switch-off'.[20]

2.20 We assess the difference in credit risks between GPBs and EDBs, and whether a higher debt premium allowance would be justified for GPBs. In particular, we consider evidence from credit rating agencies' reports on the New Zealand EDBs and GPBs, as well as debt market data. We find that there is indeed a perception of a higher risk to the creditworthiness of the gas sector. Hence, an uplift to the debt premium allowance for GPBs relative to EDBs would be justified in the New Zealand context.

2.21 First, we compare the evidence from Moody's credit reports on Vector, Powerco and Firstgas. Both Moody's and S&P assign an ESG Credit Impact Score (CIS) to the rated companies. Effectively, this score measures the impact of the company's ESG performance on its creditworthiness—i.e. a low score means that ESG factors made credit rating agencies reduce the credit rating. Therefore, we compare this ESG CIS from Moody's credit reports on Vector, and Firstgas, as well as S&P Global's credit report on Powerco.

- **Vector's** ESG score is Neutral-to-Low (CIS-2) which means that ESG factors do not have a material impact on the credit rating.[21] Moody's also provides a breakdown by environmental (E), social (S), and governance (G) aspects. Vector is scored as moderate-negative (E-3) for the environmental aspects, which is mostly due to the physical

[20] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, para 7.52.
[21] Moody's (2023), 'VECTOR Limited. Update to credit analysis', 19 January, p. 6.

climate risks associated with energy networks, particularly bushfires (i.e. not related to gas).[22]

- **Powerco** scores 'Neutral' on all of the ESG criteria ranked by S&P Global.[23] The rating is underpinned by the safe business profile of electricity and gas networks, and lower exposure to emission risks compared to pure fossil fuel power industries.[24]
- In comparison to the previous two companies, **Firstgas** is not an EDB but has been focusing solely on gas.[25] Firstgas' ESG score is 'Moderately negative' (CIS-3).[26] The lower score is driven by 'Moderately negative' performance on both environmental (E-3) and social aspects (S-3). According to Moody's, this lower score reflects the expected exposure to the risk of demand reduction, as energy networks over time transition to low-carbon sources. This effect is partly mitigated in the short-to-medium term by the role of gas as a transitional fuel.[27] In addition, the moderately negative social score (S-3) reflects 'the company's moderate exposure to demographic and social trends risk from increasing societal concerns and pressure to reduce carbon emission over time, as well as its exposure to risk associated with maintaining a responsible production owing to the risk of pipeline explosion'. In other words, the gas-specific decarbonisation factors are accounted for in the GPBs' credit ratings, and GPBs' credit ratings would have been higher if there was no decarbonisation. As a result, we expect the risk to be priced into the debt instruments available to the GPBs.

2.22 Moody's further highlights some exposure of Firstgas to the expected decline in the petrochemical use of gas and the ban on new offshore gas exploration permits in New Zealand.[28] We expect the recent recommendation by the New Zealand Climate

[22] Ibid.
[23] S&P Global (2022), 'Powerco Ltd., RatingsDirect', 13 September, p. 8.
[24] Ibid.
[25] In March 2023, Firstgas has completed its acquisition of an EDB, Eastland Networks (now renamed into Firstlight Network). See Firstgas (2023), 'Firstgas Group acquisition of Eastland Network receives OIO approval and a new name is revealed', 16 March, https://firstgas.co.nz/firstgas-group-acquisition-of-eastland-network-receives-oio-approval-and-a-new-name-is-revealed/ (accessed 18 July 2023).
[26] Moody's (2023), 'First Gas Limited. Update to credit analysis', 10 January, p. 7.
[27] Ibid.
[28] Ibid., p. 4.

Change Commission to restrict new domestic gas connections by 2025 and phase out domestic gas use by 2050 will also have an impact.[29]

2.23 Although decarbonisation risks for gas are long-term in nature, some of the factors, such as policies effective immediately and social factors, have an impact in the short-to-medium term.

2.24 On balance, the lower ESG rating of Firstgas reflects the demand reduction and asset stranding risk present in the New Zealand gas industry, which puts downward pressure on its credit rating, and is necessarily reflected in higher market debt risk premia.

2.25 As the second step in our assessment, we consider market data to see whether bond pricing implies any 'gas premium'. We select similar bond pairs issued by electricity distribution companies and gas distribution companies. The bonds are matched on their credit rating and remaining term to maturity. We have not identified any comparable electricity and gas network bonds in the New Zealand market. Thus, we consider evidence from the UK market for this analysis.

2.26 We select comparable vanilla fixed-rate bond pairs issued by electricity distribution and gas distribution companies. The bonds are matched on their credit rating and the remaining time to maturity. We divide the potential bond pairs into two categories:

- short-term bonds—with less than five years remaining to maturity;
- long-term bonds—with over 15 years remaining to maturity.

2.27 We then construct long-term and short-term 'gas premia' by subtracting the yields to maturity of electricity distributor bonds from those of the comparable gas distributor bonds. We expect the premia to be more pronounced in long-term bonds because of the long-term nature of gas-specific risks. Importantly, we consider the difference between the long-term and the short-term premia rather than each of them directly, as individual 'gas premium' estimates may be affected by the individual

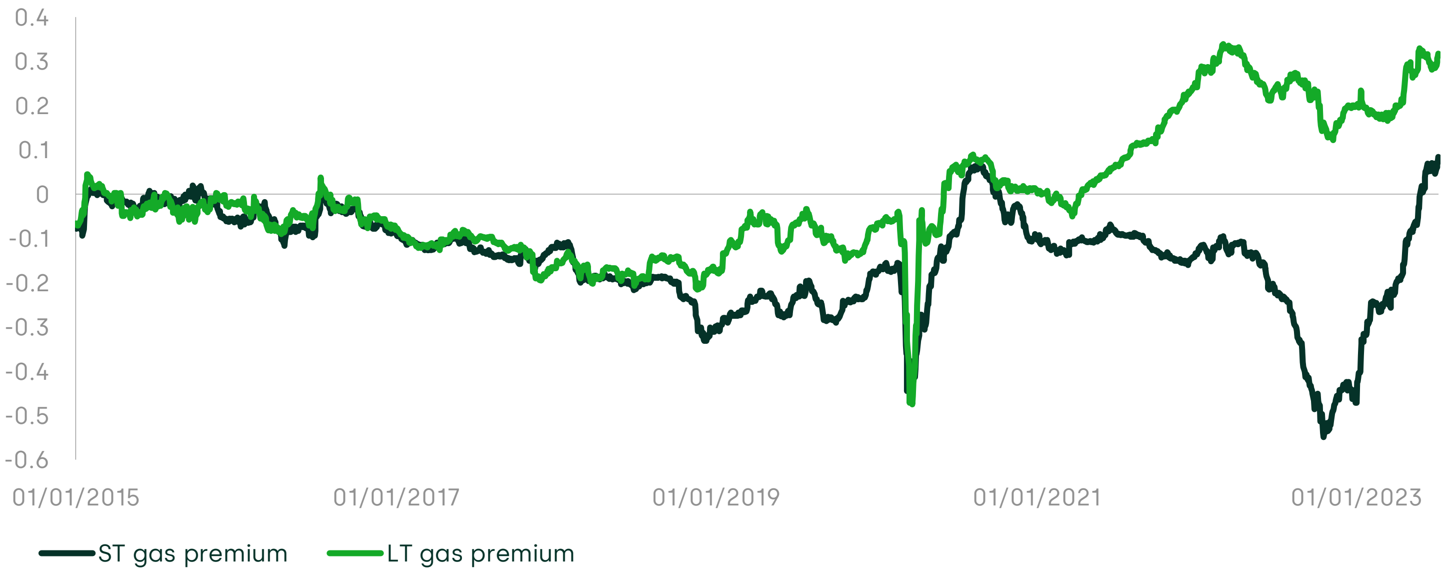
[29] Climate Change Commission (2023), '2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan', April, p. 105.

characteristics of the companies. As a control, therefore, the spread between the long-term and the short-term premia is likely to be driven significantly by the expected long-term outlook.

2.28 Figure 2.1 and Figure 2.2 below present a comparison between the bonds of two pairs of companies:

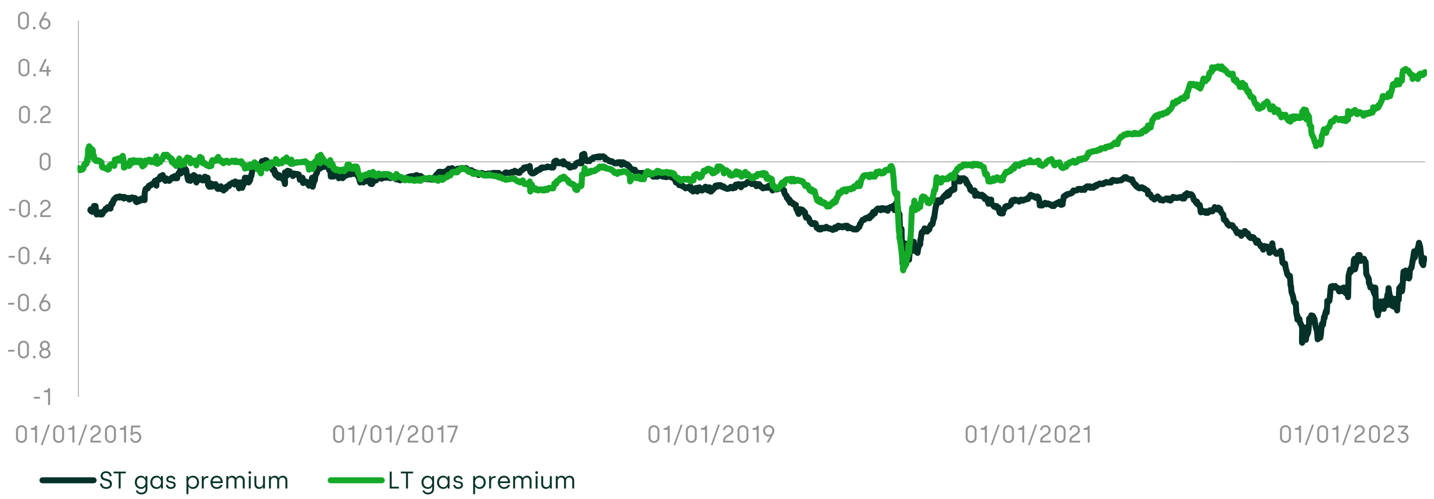
- National Grid Electricity Distribution (NGED, ex-Western Power Distribution) and Northern Gas Networks (NGN);
- NGED and Southern Gas Networks (SGN).

Figure 2.1 NGN bond premia over NGED (%)



Note: ST—short term, LT—long term. ST bonds include National Grid Electricity fixed bonds (issued by WPD) maturing in March 2027 and Northern Gas Networks fixed bonds maturing in June 2027; LT bonds include National Grid fixed bonds (issued by WPD) maturing in March 2040 and Northern Gas Networks fixed bonds maturing in March 2040.
Source: Oxera analysis of Bloomberg data.

Figure 2.2 SGN bond premia over NGED (%)



Note: ST—short term, LT—long term. ST bonds include National Grid fixed bonds (issued by WPD) maturing in May 2025 and Southern Gas Network fixed bonds maturing in February 2025; LT bonds include National Grid fixed bonds (issued by WPD) maturing in March 2040 and Southern Gas Network fixed bonds maturing in May 2040.
Source: Oxera analysis of Bloomberg data.

2.29 The figures above show a clear change in the gas premia trends. From about 2020, the long-term gas premia are significantly above the implied short-term premia. This evidence is not from the New Zealand market, and reflects only selected bonds, but it still supports the hypothesis of asset stranding and demand reduction risks being increasingly priced into gas network bonds. Furthermore, although this evidence focuses on long-term instruments, the perception of the timing of risks may differ in in different markets.

2.30 On balance, the evidence from equity markets (as presented by RAB multiples), credit rating agencies, as well as bond markets, all suggest that GPBs may face higher risks than EDBs. Hence, an uplift of the debt premium, relative to the premium awarded to the EDBs, would be justified in New Zealand.

3 The WACC percentile

3.1 The WACC percentile that the NZCC targets in the electricity and gas distribution sectors was set at the 67th percentile in the 2016 Input Methodologies.[30] This followed extensive consultation that the NZCC undertook with industry and stakeholders in 2014 in order to determine the appropriate percentile that should be targeted. As part of this consultation, in 2014, Oxera wrote two reports for the NZCC in which we explained why we considered that a percentile between the 60th and 70th was the most appropriate to aim for.[31] The NZCC took this, as well as other responses, into account in deciding on the 67th percentile. It also engaged stakeholders, for instance, holding a cost of capital workshop in 2016.[32]

3.2 In 2022, Oxera was commissioned by the 'Big Six' EDBs (Aurora, Orion, Powerco, Unison, Vector, and Wellington Electricity) as well as three GDBs (Vector, Firstgas and Powerco). In these reports, we explained that the NZCC should continue using the 67th percentile for the regulation of electricity and gas networks because:[33]

- the evidence on the costs of outages supported a WACC percentile anywhere between the 65th and 85th percentile;
- the impact of underinvestment on delaying connection of low-carbon technologies (LCTs) could create a further asymmetric distribution of outcomes (i.e. in addition to the one already

[30] New Zealand Commerce Commission (2016), 'Electricity Distribution Services Input Methodologies Amendments Determination 2016', 20 December, p. 134, https://comcom.govt.nz/__data/assets/pdf_file/0018/60543/2016-NZCC-24-Electricity-Distribution-Services-Input-Methodology-Amendments-Determination-2016-20-December-2016.pdf (accessed 5 July 2023).
[31] Oxera (2014), 'Input methodologies—Review of the "75th percentile" approach', 23 June; Oxera (2014), 'Review of expert submissions of the input methodologies', 27 October, https://www.oxera.com/wp-content/uploads/2018/07/Oxera-review-of-the-75th-percentile-approach.PDF.pdf (accessed 5 July 2023); Oxera (2014), 'Review of expert submissions of the input methodologies', 27 October, https://comcom.govt.nz/__data/assets/pdf_file/0025/88522/Oxera-response-to-submissions-on-Input-methodologies-Review-of-the-75th-percentile-approach-27-October-2014.PDF (accessed 5 July 2023).
[32] New Zealand Commerce Commission (2016), 'Input methodologies review decisions Summary paper', 20 December, Table A1, https://comcom.govt.nz/__data/assets/pdf_file/0022/60529/Input-methodologies-review-decisions-Consolidated-reasons-papers-20-December-2016.pdf (accessed 17 July 2023).
[33] Oxera (2023), 'Review of the percentile of the WACC distribution that should be targeted by the NZCC', 31 January, pp. 1–3, https://blob-static.vector.co.nz/blob/vector/media/vector-2023/oxera-review-of-the-percentile-of-the-wacc-distribution-that-should-be-targeted-by-the-nzcc.pdf (accessed 5 July 2023); Oxera (2023), 'Asset beta and WACC percentile for New Zealand gas distribution businesses'; 1 February.

considered by the NZCC) that provided further reasons to aim up on the WACC;

- we exercised judgement to consider that the upper end of the distribution (between the 80th and 85th percentiles) may be unnecessary, especially as other regulatory tools can partially mitigate the risks of underinvestment;
- the NZCC's use of the 67th percentile had achieved good outcomes for consumers because the evidence suggested that the networks had been maintained at a good, but not excessive,[34] level;
- there is value in maintaining regulatory stability, and thereby in retaining the level of the 67th percentile as previously used by the NZCC to set the WACC allowance.

3.3 In June 2023, the NZCC published its draft decision on the WACC percentile, where it concluded that the percentile appropriate for gas network regulation was the 50th and that the percentile appropriate for electricity network regulation was the 65th, as part of the current IMs review process. To our knowledge, the NZCC has not undertaken stakeholder engagement on this shift prior to publishing the DD. The reason for choosing a lower percentile for gas appears to be that the NZCC considers the impact of underinvestment on the gas networks to be relatively low.[35] This section of the report challenges this conclusion. It is structured as follows.

- Section 3A explains how the NZCC had arrived at the previous decision to set the WACC percentile for GPBs at the 67th percentile; it examines the outcomes of the current regime and whether there have been major changes that warrant removing the WACC uplift.
- Section 3B discusses the probability and costs of gas outages in response to the statements on these made in the DD. It then explains how a loss analysis model could be calibrated for the gas sector.
- Section 3C examines further possible implications of underinvestment in the gas network. These are (i) a lower-quality network with more leaks, which in turn could lead to

[34] I.e. with reference to evidence on network reliability indicators and returns to networks.
[35] New Zealand Commerce Commission (2023), 'Part 4 Input Methodologies Review 2023 – Draft decision', paras 6.105–6.112, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).

environmental costs, (ii) a delayed transition to green gases, and (iii) preventing an orderly transition.

3A Regulatory stability

3A.1 The previous decision to set a 67th percentile for gas networks

3.4 The NZCC had previously decided to apply a WACC uplift using the 67th percentile for both electricity and gas networks. The key developments and arguments used are summarised in Box 3.1 below.

Box 3.1 Summary of previous decision of a 67th percentile

The NZCC issued a decision in 2014 about the WACC percentile for the price-quality regulation of electricity line and gas pipeline services. It found that the 67th percentile of their calculated WACC distribution should be used. Given the inherent uncertainty in measuring the WACC, the NZCC reached this decision as it anticipated that the costs of underestimating the WACC would outweigh the potential costs of overestimating it.

To support its view on the optimum WACC percentile, the NZCC acquired a large quantity of analytical and empirical information—this included evidence submitted by Oxera. The move to use the 67th percentile, according to the NZCC, balances the costs of under- and overinvestment to consumers. This judgement was deemed consistent with Part 4's overriding purpose of promoting the long-term benefits of regulated services. The NZCC decision was, ultimately, based on a number of key justifications.

- Minimising the risk of investment shortfalls: by setting the WACC above the median (50th percentile), the NZCC aimed to reduce the risk that actual returns would fall short of the required return on investment. This was designed to encourage sufficient investment in the sector, as investors need confidence that they will achieved an adequate return to incentivise long-lived investments.

- Avoiding the consequences of underinvestment: the NZCC argued that the potential costs and consequences of under-investment (e.g. poorer service quality, reduced reliability, higher long-term costs) were likely to be more significant than the costs of overinvestment (e.g. slightly higher prices in the short term). Thus, they leaned towards a higher WACC to incentivise investment.
- Alignment with international practices: the NZCC considered the 67th percentile to be consistent with regulatory practices in comparable jurisdictions, and considered this would provide a good balance between the needs of consumers and the requirements of investors.

Source: New Zealand Commerce Commission (2014), 'Proposed amendment to the WACC percentile for electricity lines services and gas pipeline services', https://comcom.govt.nz/__data/assets/pdf_file/0027/88605/Proposed-amendment-to-the-WACC-percentile-for-electricity-lines-services-and-gas-pipeline-services-22-July-2014.PDF (accessed 6 July 2023).

3.5 Importantly, in its 2014 determination, the NZCC recognised the distinction between electricity lines and gas pipelines, but determined that the industries were sufficiently similar to merit the same WACC percentile being applied.[36] This was supported by the experts advising the NZCC.

- Dr Martin Lally investigated whether various percentiles should be applied to different industries, but determined that predicting these differential rates would be too complex.[37]
- Professor Ingo Vogelsang emphasised the importance of treating various circumstances identically for policy

[36] New Zealand Commerce Commission (2014), 'Proposed amendment to the WACC percentile for electricity lines services and gas pipeline services', para. X2.1, https://comcom.govt.nz/__data/assets/pdf_file/0027/88605/Proposed-amendment-to-the-WACC-percentile-for-electricity-lines-services-and-gas-pipeline-services-22-July-2014.PDF (accessed 6 July 2023).
[37] Ibid., para, 6.49.

consistency, emphasising the significance of regulatory stability. According to him, this approach eliminates complex studies and produces more predictable results.[38]

3.6 Given the regulatory precedent on the WACC percentile, when deciding whether to deviate from the previously chosen 67th percentile the NZCC could take into account and assess:

- the value of regulatory stability;
- whether there have been particular developments in the gas sector since the previous decision that warrant a change in the WACC uplift.

These factors are now discussed in turn.

3A.2 The value of regulatory stability

3.7 Regulatory stability in this context is particularly important because it provides predictability and helps with efficient market functioning.

3.8 Regulatory stability provides predictability for investors and certainty for investment decisions. This is in line with section 52R of the Commerce Act stating that '[t]he purpose of input methodologies is to promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation, or proposed regulation, of goods or services under this Part'.[39]

3.9 If regulations are frequently changing or are applied inconsistently across different industries, this increases the risk and uncertainty faced by investors. This can drive up the cost of capital, as investors demand a higher return to compensate for the additional risk. Conversely, regulatory stability can lower the cost of capital, making it more affordable for companies to invest in infrastructure and improvements. Notably, Moody's rating methodology for regulated electric and gas networks shows a 15% weighting being given to the stability and predictability of the regulatory regime. This is pertinent since credit ratings reflect, and in turn influence, the relative

[38] Ibid., para. 6.51.
[39] Ministry of Business, Innovation, and Employment (2023), 'Commerce Act 1986', 20 April, Section 52R, https://www.legislation.govt.nz/act/public/1986/0005/latest/versions.aspx (accessed 17 July 2023).

creditworthiness and thereby cost of debt financing by networks.[40]

3.10 Consistent regulation can also lead to more efficient market outcomes. If the regulatory regime is predictable and applied evenly, companies can focus on improving their operations , rather than trying to navigate a complex and shifting regulatory landscape.

3A.3 Developments for gas networks since the previous decision

Outage measures over time

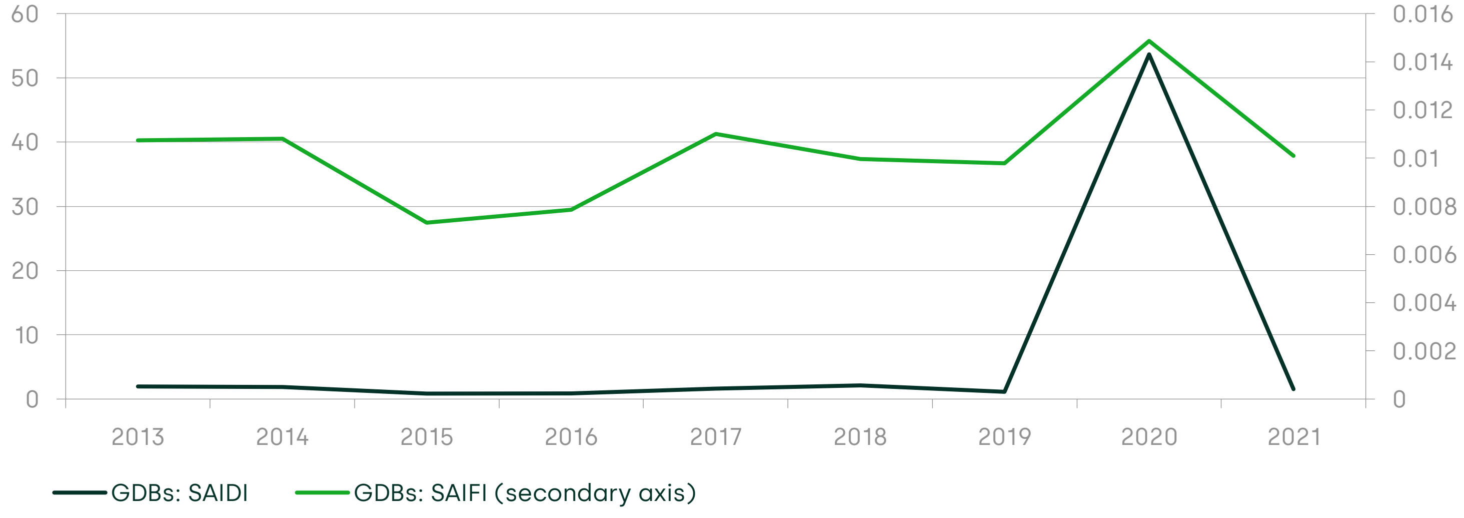
3.11 A key argument that the NZCC uses to support the removal of a WACC uplift for gas networks is the difference in the likelihood of outages. The NZCC's DD shows that common measures for outages are significantly higher for electricity than gas.[41] From this, as well as lower outage costs, it concludes that the WACC percentile should be lower for gas than electricity because the risk of an outage (and therefore a negative impact of under-investment) is lower.

3.12 Over recent years, there has been some improvement in network reliability for GDBs, as evidenced by declining System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) measures. These performance indicators represent the average outage duration and frequency for customers. From 2013 to 2021, SAIDI and SAIFI decreased by 24% and 6% respectively, demonstrating enhanced network stability and a reduction in service disruptions over this period—although the numbers fluctuate year-over-year.[42] The marked increase in 2020 is due to one event in Whanganui in February 2020 when a pressurised water main ruptured, damaging a low pressure gas main and flooding

[40] Moody's (2022); 'Rating Methodology: Regulated Electric and Gas Networks', 13 April, Exhibit 2, https://ratings.moodys.com/api/rmc-documents/386754 (accessed 10 July 2023).
[41] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, paras 6.110–6.111, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).
[42] Based on analysis of New Zealand Commerce Commission, 'Performance summaries for gas distributors', https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-performance-and-data/performance-summaries-for-gas-distributors (accessed 10 July 2023).

approximately 9km of the low pressure gas network with water.[43] This is shown in Figure 3.1.

Figure 3.1 SAIDI and SAIFI for GDBs



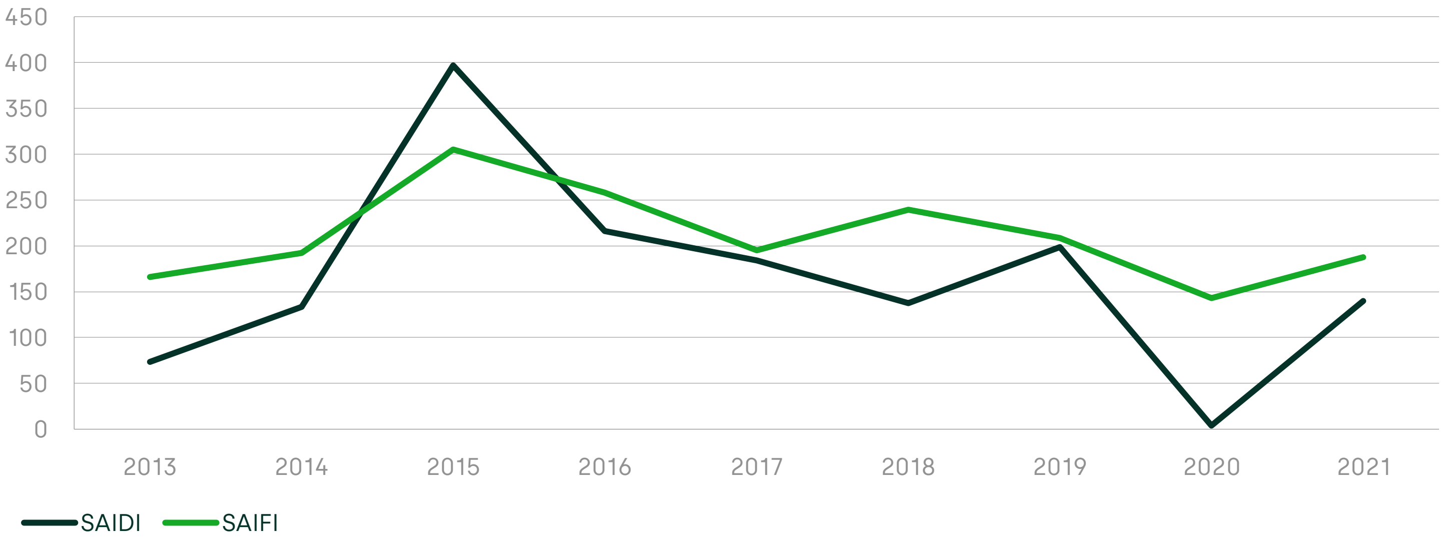
Source: Oxera analysis based on New Zealand Commerce Commission, 'Performance summaries for gas distributors', https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-performance-and-data/performance-summaries-for-gas-distributors (accessed 10 July 2023).

3.13 Figure 3.2 highlights the relative performance of gas and electricity distributors across the SAIDI and SAIFI metrics. Both GDBs and EDBs have been improving over the period. The ratios of scores (scores for EDBs divided by scores for GDBs) for both SAIDI and SAIFI fluctuate, but are relatively similar in 2014 and 2021. This indicates that the magnitude of differences in reliability metrics between EDBs and GDBs has remained relatively constant, and has actually been decreasing after 2015 (i.e. the scores for EDBs and GDBs have become more similar in recent years). The development of the interruption indices is broadly aligned in the two industries, and supports the assumption by the NZCC in its 2014 determination that the

[43] Gas Association of NZ Technical Advisory Group (2021), '2021 KPI report', Excel sheet 'GANZ KPIs'.

industries are sufficiently similar to merit the same WACC percentile being applied,[44] at the 67th percentile.

Figure 3.2 Relative performance electricity and gas distribution businesses



Note: calculated by dividing the total SAIDI/SAIFI for electricity distributors by the total SAIDI/SAIFI for gas distributors.
Source: Oxera based on performance data for gas and electricity distributors.

3.14 While it is true that the outage probabilities for gas networks are lower than those for electricity, there are at least two further points to consider in relation to this.

- As noted above, the order of magnitude of the difference in SAIDI and SAIFI numbers between gas and electricity networks has remained similar over time such that the retention of a 67th percentile in the gas sector as per the previous IMs decision is reasonable.
- The fact that reliability of the network has been improving should be rewarded, not penalised in a regulatory system. SAIDI and SAIFI are somewhat endogenous measures—that is, network operators have a certain degree of control over

[44] New Zealand Commerce Commission (2014), 'Proposed amendment to the WACC percentile for electricity lines services and gas pipeline services', para. X2.1, https://comcom.govt.nz/__data/assets/pdf_file/0027/88605/Proposed-amendment-to-the-WACC-percentile-for-electricity-lines-services-and-gas-pipeline-services-22-July-2014.PDF (accessed 6 July 2023).

them. Basing a financial parameter, such as the WACC uplift on this endogenous metric, can lead to unintended incentive properties of the regulatory scheme. For instance, if GPBs suffered more disruptions, and the NZCC sought to reward this with a WACC increase, that would not appear to be a desirable incentive property of the regulatory regime, in line with the consumers' interest.

Financial performance over time

3.15 In addition to the network reliability measure, we also consider the financial performance of gas networks to be a relevant factor. If the previously used WACC uplift had led to a regulated WACC that was significantly above companies' actual WACC, then we may find incentives for, and evidence of, over-investment. Specifically, this might be the case if the allowed returns were in excess of the required returns, leading to outperformance, while service quality was declining.

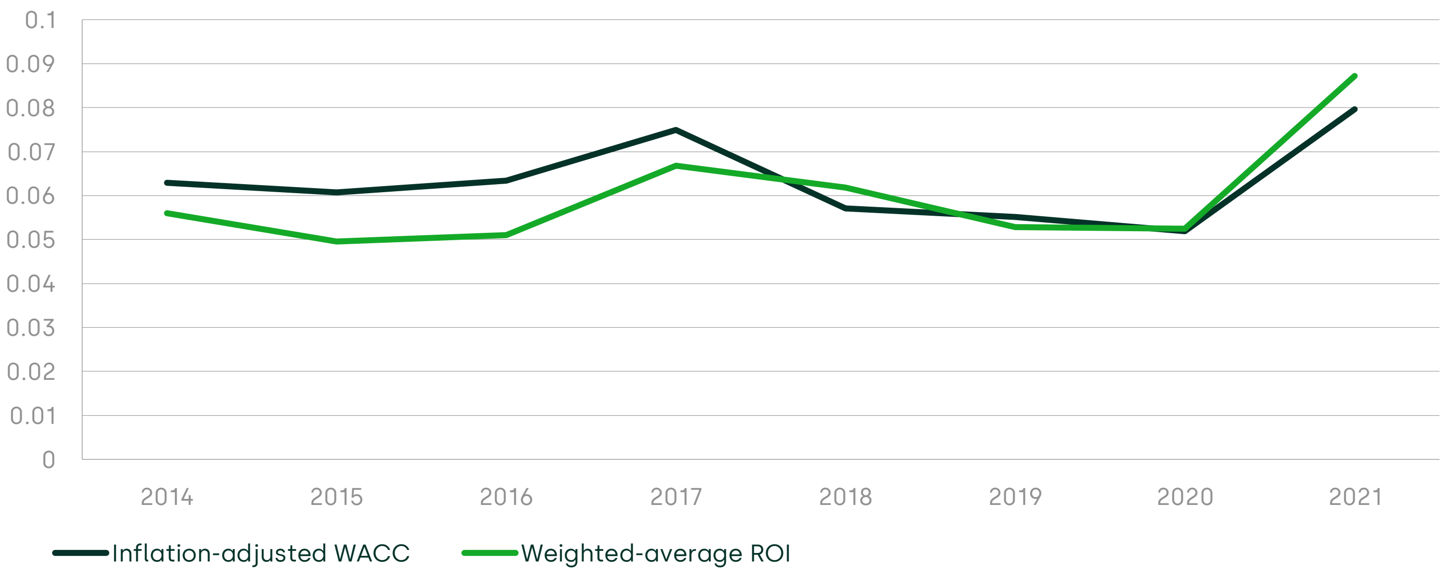
3.16 Recent data suggests that the present level of the WACC percentile, and the uplift applied by the NZCC in 2014, is appropriate. The performance of local gas pipelines—such as GasNet, Firstgas, Powerco, and Vector—was aligned with expectations, with little to no evidence of outperformance.

3.17 Local gas pipeline firms have demonstrated steady profitability without a priori evidence of excessive returns. Despite an increase in annual income of NZ$5m since 2014, this gain can be attributed to an increase in the number of customers, particularly residential and small business consumers. Also, the average customer payment has declined by NZ$36 in nominal terms since 2014, or NZ$99 in real terms when adjusted for inflation.[45]

3.18 More specifically, Figure 3.3 uses data reported by the NZCC to compare the return on investment for a gas distribution business to its WACC, to assess whether the GDBs are making excessive profit.

[45] New Zealand Commerce Commission (2023), 'Trends in gas pipeline business performance', para.181, https://comcom.govt.nz/__data/assets/pdf_file/0020/273413/Trends-in-gas-pipeline-performance-report-2023.pdf (accessed 6 July 2023).

Figure 3.3 Return on investment vs post-tax WACC adjusted for ex post inflation across all local gas pipeline businesses, 2014–21



Source: Oxera analysis based on data from New Zealand Commerce Commission (2023), 'Trends in gas pipeline performance', Figure 68, 8 February, https://comcom.govt.nz/__data/assets/pdf_file/0020/273413/Trends-in-gas-pipeline-performance-report-2023.pdf (accessed 10 July 2023).

3.19 The NZCC's own trends analysis suggests that GPBs have not been making excessive returns:

> Overall, returns across industry and for each local gas pipeline business were generally in line with the estimated WACC adjusted for ex-post inflation, suggesting that local gas pipeline businesses have generally not made excessive returns over the last eight years.
>
> **New Zealand Commerce Commission (2023), 'Trends in gas pipeline business performance', 8 February, para. 181.**

3.20 The total number of outages across all local gas pipeline networks has been declining since 2014, indicating an improvement in service quality. Other metrics, such as the number of customer emergencies, customer complaints, and the duration and frequency of outages, have also reduced or remained steady.[46] These advancements indicate that customers are obtaining high-quality services while firms are not making excessive profits.

3.21 Overall, it appears that the regulatory environment has resulted in good performance, better service quality, and a lack of significant outperformance by GDBs. From 2019 to 2021, GDBs have invested NZ$4.58m per year (on average) in new CAPEX to maintain reliability and safety requirements.[47] This generally does not suggest that the previously chosen WACC uplift was too high—and changing the WACC percentile under these circumstances may inject needless risks and volatility into an otherwise stable system.

3B Cost of gas outages

3.22 The NZCC's draft decision to remove the WACC uplift for GPBs is largely based on the arguments that gas outages are supposedly less likely and less costly than electricity outages. The reliability of the gas network—and the potential adverse incentives of 'punishing' networks for having a reliable network—are discussed in section 3A.3. We now turn to the cost of gas outages before setting out how a loss-analysis framework might be calibrated for the gas sector.

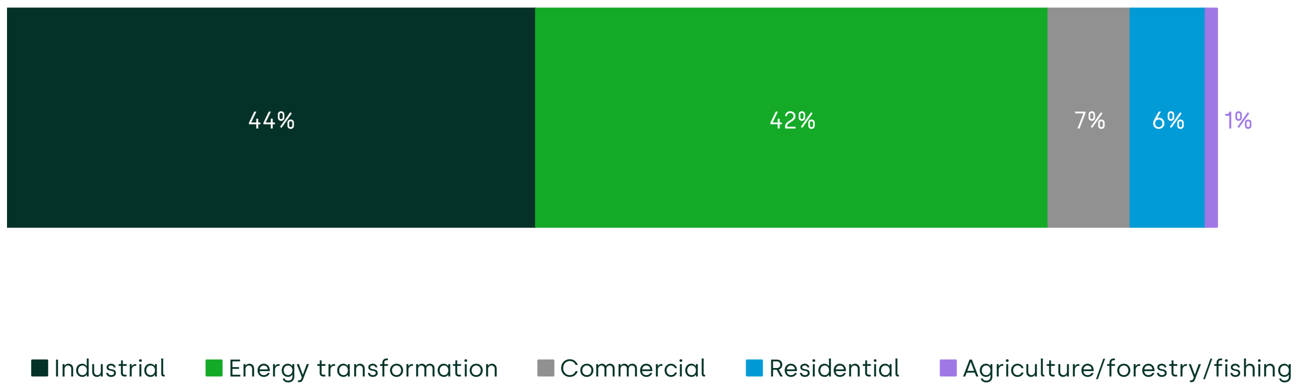
3B.1 Cost of gas outages

3.23 The DD states that while the NZCC does not have enough evidence to estimate a magnitude, it is expected that the cost of outages will be lower for gas users than for electricity users. The NZCC argues that it expects this to be the case because gas is a secondary energy source for many users. The DD also mentions that electricity outages can result in gas outages, for instance when gas is used for cooking or hot water.[48] Here, the NZCC seems to focus on the impact of gas outages on domestic consumers, seemingly omitting the impact on industry, where gas can be a primary source of energy.

[46] Ibid., para. 43.
[47] NZCC (2021), 'Total gas distribution', https://comcom.govt.nz/__data/assets/pdf_file/0027/292860/Total-gas-distribution-2021.pdf (accessed 18th July 2023)
[48] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, para. 6.106, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).

3.24 Indeed, the largest proportion of gas demand in New Zealand is from industrial users who consumed 44% of the total gas demanded in 2022. As Figure 3.4 below shows, the gas consumed from the residential sector was less than one tenth of the total gas demand in the same year. According to data from the New Zealand Ministry of Business, Innovation & Employment (NZMBIE), this composition of gas demand has remained stable over time, with industries such as food processing and chemicals using 23–40% of the total gas demand between 2010 and 2022.[49]

Figure 3.4 Composition of gas consumption in 2022



Note: Percentages calculated based on annual PJ data and excluding 'non-energy use' of gas.
Source: Oxera analysis of data from New Zealand Ministry of Business, Innovation & Employment (2023), 'Data tables for gas', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/ (accessed 5 July 2023).

[49] Oxera analysis of data from New Zealand Ministry of Business, Innovation & Employment (2023), 'Data tables for gas', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/ (accessed 5 July 2023).

3.25 Accordingly, studies on the cost of gas outages in New Zealand show that costs to consumers can be substantial.[50] For example, the gas outage caused by a failure in the Maui gas transmission pipeline in 2011 resulted in significant economic loss to many industrial consumers. The outage lasted five days and prevented businesses, such as major food processors, to carry out their operations for periods of between two and six days. [51] Some health services in the upper North Island were also disrupted.[52]

3.26 As an example of the industrial disruption, the Maui gas outage impeded the production and processing of milk in major production units in the affected area and led to the disposal of 48.3m litres of raw milk. This amounted to NZ$46m of losses for the dairy industry. According to the study, if the outage was prolonged there would be larger economic effects, as dairy stock would have to be 'dried off' which would result in a dramatic decrease in milk production.[53] Similarly, according to estimates from the NZMBIE, large industrial users without alternative fuel capability lost up to NZ$25m daily.[54]

3.27 In addition to the above economic costs, the outage created risks for environmental contamination from milk disposal on farms, with a small number of spills into waterways being reported.[55]

3.28 According to the NZMBIE, the gross economic cost of this event was estimated at NZ$200m[56] or around NZ$266m in 2022 prices.[57] We note that gas outage events in areas of Australia have resulted in higher cost estimates. For instance, the 1998 Longford gas explosion in Victoria which lasted for 20 days

[50] See for example New Zealand Ministry of Business Innovation & Employment (2012), 'Review of the Maui Pipeline Outage of October 2011', October; WorleyParsons (2014), 'Gas Disruption Study: Report on the potential impacts on the NZ gas market', January.
[51] New Zealand Ministry of Business Innovation & Employment (2012), 'Review of the Maui Pipeline Outage of October 2011', October, p. 13.
[52] Ibid.
[53]New Zealand Ministry of Business Innovation & Employment (2012), 'Review of the Maui Pipeline Outage of October 2011', October, pp. 17–18.
[54] Ibid., p. 26.
[55] Ibid., p. 15.
[56] New Zealand Ministry of Business Innovation & Employment (2012), 'Review of the Maui Pipeline Outage of October 2011', October, p. 50. The figure is gross because it does not account for insurance claims and the substitution or flow-on effects (e.g. firms increasing capability in other facilities to compensate for the loss in production).
[57] Using a GDP deflator from the World Bank to inflate prices from 2012 to 2022. The World Bank, 'GDP deflator: New Zealand', https://data.worldbank.org/indicator/NY.GDP.DEFL.ZS.AD?locations=NZ (accessed 17 July 2023).

resulted in costs of AU$1.3bn (about NZ$1.4bn)[58], and the Varanus Island gas explosion in 2008 resulted in insurance costs of over AU$200m (about NZ$215m)[59] and is estimated to have cost the state up to AU$2.4bn (about NZ$2.6bn).[60,61]

3.29 The cause of the Maui pipeline outage was due to a landslide movement. Although external events such as this are not directly linked to reliability investment on the gas network, the cost of risk and impact mitigation is. For example, following the Maui gas outage, the pipeline owner increased the management of sites with high landslide and erosion risks through activities, such as manual assessment surveys for land movement and improved drainage.[62] We understand from the GPBs that high-risk sites have since become priorities for remediation, such as the Pariroa bypass installed in 2018.[63]

3.30 In the context of climate change where severe weather events are occurring more frequently and with greater severity, the probability and impact of physical incidents such as heavy rainfall and landslides are likely to increase in the future.[64] It is therefore reasonable to expect that there would be a higher need for steady investment in increasing asset resilience. This has been recognised in other sectors; for instance by the UK water regulator Ofwat, which states that it is actively supporting the sector in responding to the key risks associated with climate change.[65] Even where the gas network is generally more reliable than the electricity network, any (incentives for)

[58] Australian Institute for Disaster Resilience, 'Longford, Victoria, September 1998. Industrial-Longford gas explosion', https://knowledge.aidr.org.au/resources/industrial-longford-gas-explosion/ (accessed 17 July 2023).
[59] Australian Institute for Disaster Resilience, 'Western Australia, June 2008. Varanus Island gas explosion', https://knowledge.aidr.org.au/resources/industrial-varanus-island-gas-explosion/ (accessed 17 July 2023).
[60] The West Australian (2018), 'Varanus Island a decade on: The remote explosion that ignited a WA gas crisis', 2 June, https://thewest.com.au/business/oil-gas/varanus-island-a-decade-on-the-remote-explosion-that-ignited-a-wa-gas-crisis-ng-b88850707z (accessed 17 July 2023).
[61] We note that these costs would need to be made comparable (e.g. adjusting the price base and accounting for differences in size). Nevertheless they serve as a useful cross-check for the broad magnitude of gas outage costs.
[62] New Zealand Ministry of Business Innovation & Employment (2012), 'Review of the Maui Pipeline Outage of October 2011', October,, p. 3.
[63] Information provided by Firstgas. See, for instance, New Zealand Energy Excellence Awards (2019), 'First Gas Pariroa pipeline bypass', https://www.energyawards.co.nz/content/first-gas-pariroa-pipeline-bypass-0 (accessed 18 July 2023).
[64] Smith, H. G., Neverman, A.J., Betts, H. and Siekermann, R. (2023), 'The influence of spatial patterns in rainfall on shallow landslides', *Geomorphology*, **432**, September, https://www.sciencedirect.com/science/article/pii/S0169555X23002155 (accessed 11 July 2023).
[65] Ofwat (2022), 'Ofwat's 3rd Climate Change Adaptation Report', February, Section 4, https://www.ofwat.gov.uk/wp-content/uploads/2022/01/Ofwats-3rd-Climate-Change-Adaptation-Report.pdf (accessed 11 July 2023).

future underinvestment may lead to significant costs to gas consumers from low-probability, high-impact events such as the above, to the extent that these could be mitigated by potentially discretionary or anticipatory investments,[66] in relation to reducing physical risks to assets. We highlight that removing the WACC uplift for GPBs could incentivise potential underinvestment in planning and reinforcing actions that pre-emptively help mitigate resilience risks and impacts.

3.31 The above event shows that a gas outage would disproportionately affect industrial users who rely on a steady gas supply for their business. Indeed, the proportion of gas consumed by industrial users when the Maui outage occurred was 78%, which is very close to the industrial gas consumption in 2022, as shown in Figure 3.4.[67] This high dependence of several industrial and commercial businesses on gas implies that the costs of outages can be significant for gas users due to potential loss of production, with the Maui pipeline outage event being valued at around NZ$266m.[68]

3B.2 Calibrating the loss analysis framework for GPBs

3.32 We recognise that the loss analysis framework has been developed with reference to the electricity sector. Nevertheless, to put the outage costs for the gas sector mentioned in the previous section in perspective, we calibrate the NZCC's own WACC uplift model for GPBs.[69] This is helpful because there are two countervailing factors driving the differences between electricity and gas companies in the model.

3.33 First, outage costs are likely to be lower in the gas sector than for electricity. This lowers the optimal WACC percentile for gas because any underinvestment (as a result of a regulated WACC that is set too low) would, a priori, be less costly than in the electricity sector.

[66] To the extent that there is uncertainty about whether or not investments in physical risk mitigation will be needed or effective.
[67] Oxera analysis of data from New Zealand Ministry of Business, Innovation & Employment (2023), 'Data tables for gas', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/ (accessed 5 July 2023).
[68] In 2022 prices.
[69] New Zealand Commerce Commission (2023), 'Part-4-IM-Review-2023-Cost-of-capital-topic-paper-calculations-spreadsheet_-NSS-spreadsheet-model-and-WACC-percentile-spreadsheet-model-June-2023', 14 June.

3.34 Second, the RAB for GPBs is lower than for electricity networks. We find the RAB (for distribution and transmission) to be NZ$2.1bn compared with NZ$18.4bn in the NZCC's model for electricity.[70] This increases the optimal WACC percentile for gas compared to electricity, because a higher WACC uplift results in lower costs to consumers compared with electricity (i.e. RABxWACC is higher in the electricity sector than in the gas sector).

3.35 We use the NZCC's model to obtain an indication of the optimal WACC percentile in the gas sector, using the same methodology as for electricity. We find it to be a useful cross-check in terms of the magnitude of a potential WACC uplift for gas. We note that there may be limitations to applying this methodology if, for example, gas outage costs are an imperfect measure of the economic costs that are imposed for asset failures in the gas sector. We also note that the probability of outages does not directly feed into the model, so any difference in the likelihood or frequency of outages between gas and electricity is not reflected in this exercise.

3.36 The input parameters in the model are as follows.

- Outage costs: we run a scenario with outage costs of NZ$266m as found in the Maui pipeline incident and inflated to 2022 prices. We also use the model to solve for the level of outage cost at which the optimal WACC percentile for gas is the 67th percentile (as used in the previous regulatory period), and the level at which it is equal to the 50th percentile (as chosen now).
- RAB: based on disclosure data published by the NZCC, we find the latest RAB for distribution companies to be NZ$1.16bn and for Firstgas Transmission to be NZ$0.96bn.[71]
- Tax rate: unlike the NZCC, we do not apply a tax rate to the RAB. This is because remuneration for corporate taxes does not accrue as a return to investors. Rather, it would be

[70] Calculated based on New Zealand Commerce Commission (2023), 'Gas distribution information disclosure data 2013-2022' and 'Gas transmission information disclosure data 2013-2022', 29 June, https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-performance-and-data/information-disclosed-by-gas-pipeline-businesses (accessed 11 July 2023).
[71] Calculated based on New Zealand Commerce Commission (2023), 'Gas distribution information disclosure data 2013-2022' and 'Gas transmission information disclosure data 2013-2022', 29 June, https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-performance-and-data/information-disclosed-by-gas-pipeline-businesses (accessed 11 July 2023).

more reasonable to consider that any taxes that networks recover through energy tariffs are ultimately collected on behalf of, and for, the welfare of society including the energy users within New Zealand. This is discussed in more detail in our report for EDBs.[72] We also report the corresponding numbers including the tax adjustment in footnotes.

3.37 The results are as follows.[73]

- At outage costs of NZ$266m, the optimal WACC percentile is between the 79th and 90th percentile (using thresholds of when under-investment occurs of 1% and 0.5%, respectively).[74]
- At outage costs of NZ$110m, the optimal WACC percentile is between the 58th and 75th percentile (using thresholds of when underinvestment occurs of 1% and 0.5%, respectively). This would give an average optimal WACC percentile of 67%[75], i.e. an uplift in line with the NZCC's previous decision.[76]
- We also calculate the implied outage costs at which the optimal percentile would be the 50th percentile. These are NZ$63m and NZ$88m at thresholds of 0.5% and 1%, respectively.[77]

3.38 This means that even though outage costs in the gas sector are likely to be less costly than in the electricity sector, this is potentially offset by a lower RAB for GPBs. The optimal WACC percentile based on this analysis—which is not taking into account the probability of outages—is therefore likely to be above the 50th percentile, with the evidence supporting a percentile in line with the previously used 67th percentile.

[72] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital. Prepared for the New Zealand electricity distribution businesses', 19 July.
[73] These results have been obtained using the 'goal seek' functionality in NZCC's model in combination with the input assumptions set out above.
[74] Without removing the tax adjustment, the corresponding percentiles are the 86th and 73rd percentile.
[75] The outage cost estimate giving an average optimal WACC percentile of 67% when using the tax uplift would be NZ$151m.
[76] Oxera (2023), 'Asset beta and WACC percentile for New Zealand gas distribution businesses'; 1 February.
[77] The corresponding figures without removing the tax adjustment would be NZ$87m and NZ$122m.

3C Further effects of underinvestment in the gas network

3.39 While the loss analysis framework is centred around the cost of gas outages, environmental costs associated with potential underinvestment in gas infrastructure are also important to consider. Additional emissions related to gas escapes or to potential delays in the transition to renewable gas—which could be caused by underinvestment—may undermine the New Zealand government's efforts to reach its zero-emissions target by 2050,[78] and could result in considerable abatement costs.

3.40 The following subsections explain why risking underinvestment in gas network infrastructure—which might occur as a result of removing the WACC uplift—could increase the probability of environmental costs in the future through increased gas leaks (section 3C.1) and a potential delay in the adoption of renewable gases, such as green hydrogen and biomethane, to the extent that supply constraints allow (section 3C.2).[79] These costs are additional to any outage costs.

3.41 Additionally, we note that underinvestment may prevent an orderly transition. That is, gas network operators may reduce investments, leading to a discontinuation of services for certain parts of the network. This is discussed in section 3C.3.

3C.1 The environmental cost of underinvestment in terms of gas escapes

3.42 Gas leakage inevitably occurs throughout the transmission and distribution network due to, for example, subsurface damage of pipes or leaking through seals due to aging equipment. Gas leakage is relevant for two reasons.

3.43 First, gas leaking from pipes is lost gas that users cannot consume. According to data from the NZMBIE, the transmission and distribution losses of natural gas have been stable at c. 1% of the total gas consumption since 2010. This equalled 725TJ in

[78] Ministry for the Environment (2019), 'Climate Change Response (Zero Carbon) Amendment Act 2019', 13 November, https://www.legislation.govt.nz/act/public/2019/0061/latest/LMS183736.html (accessed 5 July 2023).
[79] The availability of adequate levels of biogas which is the base for biomethane tends to be constrained due to limitations of adequate levels of feedstock, especially if this is costly and/or not feasible to import.

2022, which is one tenth of the gas consumed from residential consumers.[80]

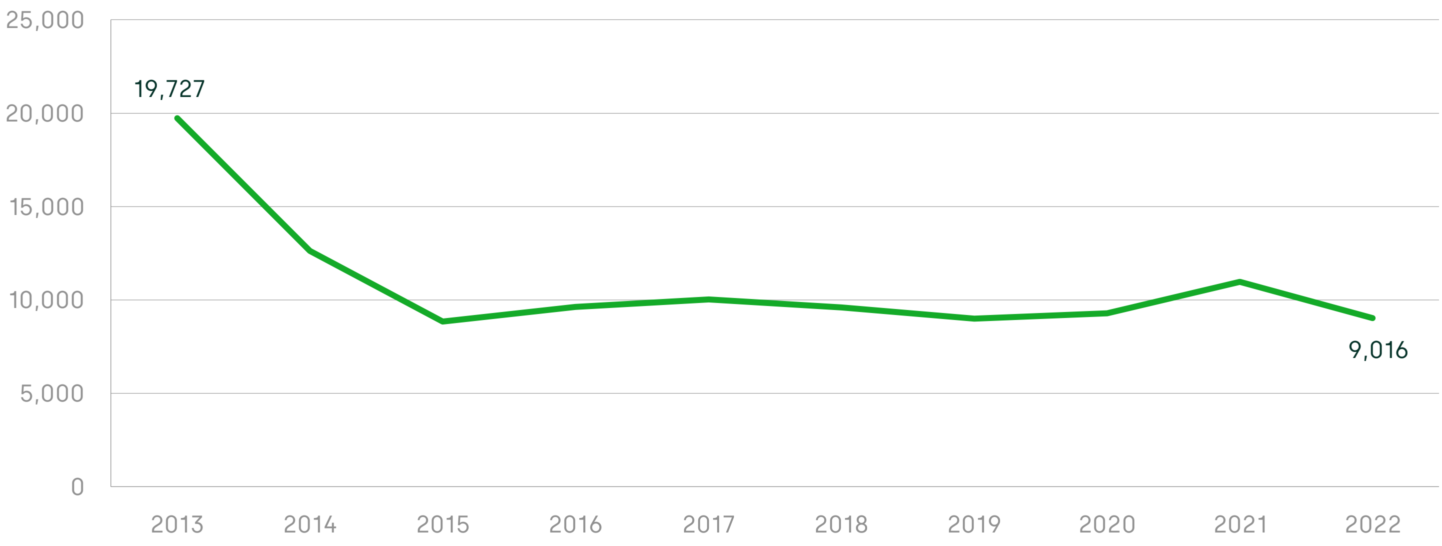
3.44 Second, the gas escaping to the atmosphere can impose costs on society through the impact it has on the environment. This is the focus of this sub-section. The reason for the significant environmental cost is that the biggest proportion of gas is methane (c. 82%) which traps 25 times more heat than a ton of CO_2, thereby contributing significantly to global warming. It is estimated that the average greenhouse gas emissions generated by one gas leak incident amount to $27tCO_2e$—this is the equivalent to the emissions generated by 35 return trips from Auckland to Sydney by plane.[81]

3.45 Therefore, there is merit in considering the costs of increased gas leakages to consumers. In fact, NZCC data in Figure 3.5 below shows that the number of gas leakages and escapes from the distribution and transmission network have decreased by 54% between 2013 and 2022. This works as evidence of how the regulatory system has been effective so far in creating sufficient investment to sustain the network and control leakage. As the network ages and extreme weather events exacerbate in the future, increasing the probability of geological erosions and movements, there is likely to be a need for increasing surveying maintenance and replacement.

[80] Oxera analysis of data from New Zealand Ministry of Business, Innovation & Employment (2023), 'Data tables for gas', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/ (accessed 5 July 2023).

[81] The emission estimate is based on Oxera analysis of data on gas leaks and escapes published by the NZCC, the transmission and distribution losses of gas published by the NZMBIE. The gas leakage was converted to CO_2e emissions using data from Firstgas. A return trip from Auckland to Sydney is estimated to emit 0.788tCO2e, based on an online calculator available at: https://co2.myclimate.org/en/portfolios?calculation_id=5957846 (accessed 6 July 2023). See New Zealand Commerce Commission (2023), 'GDB ID Database 2013-2022 Public version – version 1.0', 29 June; New Zealand Commerce Commission (2023), 'GTB ID Database 2013-2022 Public version – version 1.0', 29 June; and New Zealand Ministry of Business, Innovation & Employment (2023), 'Data tables for gas', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/ (accessed 5 July 2023).

Figure 3.5 Number of gas escapes and leaks from the transmission and distribution network



Source: Oxera analysis of data from the New Zealand Commerce Commission (2023), 'GDB ID Database 2013-2022 Public version – version 1.0', 29 June; New Zealand Commerce Commission (2023), 'GTB ID Database 2013-2022 Public version – version 1.0', 29 June.

3.46 The leakage reductions from 2013 to 2022 resulted in significant carbon savings over this period, with the shadow cost of the abated CO_2 in 2022 compared to 2013 levels estimated to be around NZ$31m.[82] This abatement has resulted in a welfare benefit to society from lower emissions. Nonetheless, even the level of leakage in 2022 implies NZ$26m in shadow carbon costs.[83] Accordingly, it is clear that the regulatory system should (continue to) incentivise adequate levels of investment in leakage repair and prevention to further reduce these costs, which can be significant drivers of social costs, and are additional to outage costs discussed in the previous section.

[82] This is calculated using the leakage data shown in Figure 3.5 and converting it to CO_2e emissions using the average emissions per leak/escape based on data from Firstgas. We then value the difference in emissions between 2013 and 2022 at 2022 carbon prices (using the central shadow price of carbon sourced from New Zealand Treasury (2022), ' Information on the shadow price of carbon (OIA-20210278)', 5 April, https://www.treasury.govt.nz/sites/default/files/2022-03/oia-20210278.pdf (accessed 7 July 2023).
[83] Oxera analysis using the central shadow price of carbon sourced from New Zealand Treasury (2022), 'Information on the shadow price of carbon (OIA-20210278)', 5 April, https://www.treasury.govt.nz/sites/default/files/2022-03/oia-20210278.pdf (accessed 7 July 2023).

3C.2 Decarbonisation risks of delaying the transition to low carbon gases

3.47 To support New Zealand's decarbonisation objectives, the government recognises the importance of transitioning away from fossil gas. To inform its Energy Strategy, the government is currently developing a gas transition plan in which it also intends to explore pathways for a renewable gas market.[84] Renewable gases such as biomethane and hydrogen could serve as energy carriers in a net-zero emissions world and may play an important role in decarbonisation of existing natural gas users and hard-to-abate use cases. [85]

3.48 The transition to renewable gases does not necessarily require new dedicated networks. Biomethane and synthetic methane are chemically indistinguishable from natural gas, and can therefore use the existing pipeline infrastructure without any modifications.[86] Even hydrogen can be integrated into existing gas infrastructure. This can be done in three ways: i) through blending hydrogen with natural gas and transporting it through existing gas pipelines; ii) by converting existing gas infrastructure into dedicated hydrogen networks; or iii) through methanation, i.e. converting hydrogen and CO_2 to e-methane and injecting this into pipeline networks.[87]

3.49 These different measures of integration are already being explored by GPBs in New Zealand. Firstgas, for example, is currently testing the feasibility of delivering a blend of natural gas with up to 20% hydrogen, by volume, through its existing pipeline infrastructure in the short term, and is considering whether it is feasible to convert its network to 100% hydrogen transport in the long term.[88] Firstgas is also working on a project

[84] Ministry of Business, Innovation & Employment (2023), 'Gas Transition Plan', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/gas-transition-plan/ (accessed 17 July 2023).
[85] Renewable gases are gases produced from renewable energy sources. These include biomethane, synthetic natural gas, and green hydrogen; see Figure 7 in European Research Institute for Gas and Energy innovation (2021), 'Theses for the european energy future', May, p. 17, https://erig.eu/wp-content/uploads/2021/05/ERIG-Theses-EU-energy-future.pdf (accessed 18 July 2023).
[86] International Energy Agency (2020), 'Outlook for biogas and biomethane', March, p. 9, https://iea.blob.core.windows.net/assets/03aeb10c-c38c-4d10-bcec-de92e9ab815f/Outlook_for_biogas_and_biomethane.pdf (accessed 18 July 2023).
[87] Entsog, GIE and Hydrogen Europe (n.d.), 'How to transport and store hydrogen – facts and figures', p. 3, https://www.entsog.eu/sites/default/files/2021-05/ENTSOG_GIE_HydrogenEurope_QandA_hydrogen_transport_and_storage_FINAL_0.pdf (accessed 6 July 2023).
[88] Firstgas Group (2021), 'Firstgas Group announces plan to decarbonise gas pipeline network in New Zealand', 29 March, https://firstgas.co.nz/firstgas-group-announces-plan-to-decarbonise-gas-

with Ecogas at Reporoa to inject biomethane into the Broadlands transmission network; this is the first utility scale renewable gas injection into a commercial gas network in New Zealand.[89]

3.50 Even the use of existing infrastructure will, however, require investments to maintain and adapt the current network for the transmission and distribution of renewable gases. The network location, scale and functionality is required to be maintained to maximise the impact of any renewable gas project with respect to both production location flexibility and end-user connectivity. In its hydrogen feasibility study, Firstgas shows that several components of the network, such as compression and metering, would require modifications even for a 20% blend.[90] General underinvestment in maintenance, reinforcements and additional components may delay the rollout of renewable gases, thereby reducing their ability to make a timely contribution to the energy transition, and therefore emissions savings.

3.51 This subsection provides some stylised calculations of how underinvestment in gas networks may affect the adoption of renewable gases, using the hydrogen roll-out in New Zealand as an illustrative example. The objective is to provide an order of magnitude estimate of the costs resulting from the additional emissions that would occur if the hydrogen adoption were delayed as a result of a lack of investments in pipeline infrastructure. This is a potential cost that is additional to the outage cost that feeds into the loss analysis framework.

3.52 Our analysis relies on the hydrogen scenarios that were developed for the NZMBIE by Castalia, an infrastructure advisory. In its report, Castalia provides three demand scenarios for green hydrogen[91] for different use cases in the transport and

pipeline-network-in-new-zealand-3/#:~:text=In%20Monday's%20announcement%2C%20Firstgas%20Group,to%20existing%20appliances%2C%20it%20said (accessed 7 July 2023).

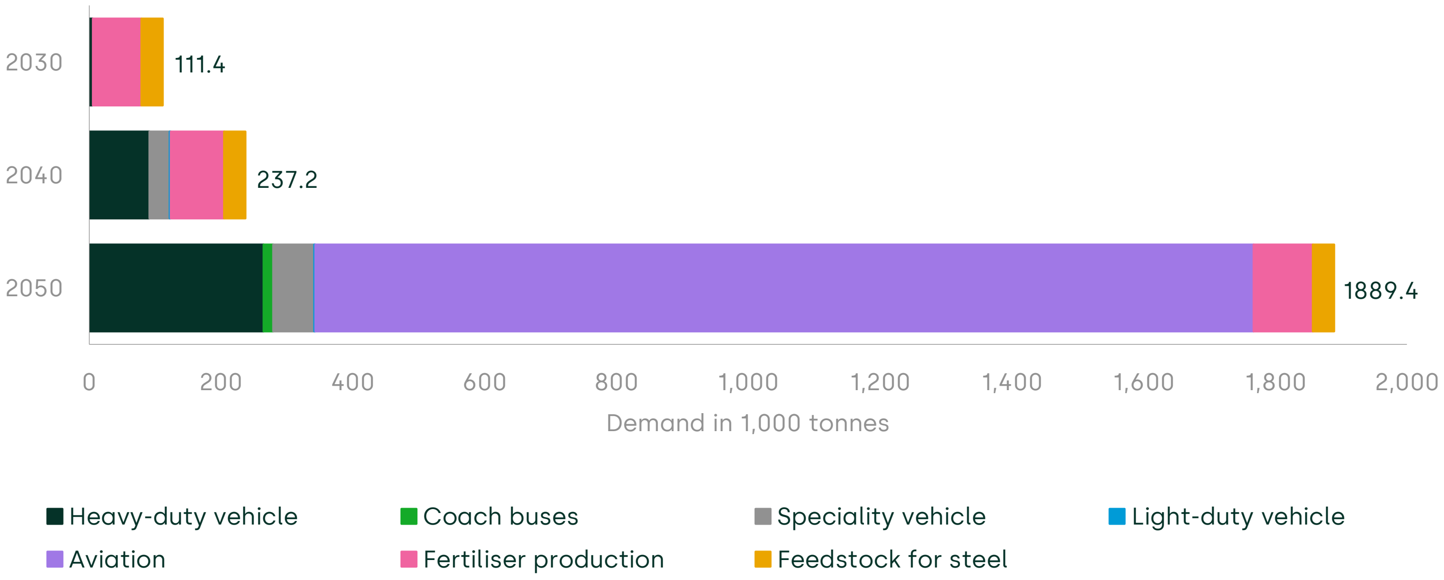
[89] Firstgas Group (2021), 'Firstgas and Ecogas to turn kerbside waste into renewable gas for use in homes and businesses', 8 December, https://gasischanging.co.nz/news/firstgas-and-ecogas-to-turn-kerbside-waste-into-renewable-gas-for-use-in-homes-and-businesses/ (accessed 18 July 2023).

[90] Firstgas Group (2021), 'Hydrogen Feasibility Study – Summary Report', https://firstgas.co.nz/wp-content/uploads/Firstgas-Group_Hydrogen-Feasibility-Study_web_pages.pdf (accessed 6 July 2023), pp. 38–39.

[91] That is, hydrogen produced via electrolysis where electricity comes from low-carbon sources.

industry sectors.[92] The base scenario is shown in Figure 3.6 below. The scenarios presented in the report are projections under business as usual, i.e. under current government targets and objectives.[93] We note that while the Castalia report is being used to inform the New Zealand government's hydrogen roadmap, the roadmap itself is yet to be published. Official demand projections may therefore still be subject to change.

Figure 3.6 Projected green hydrogen demand by use case (base scenario)



Note: The Castalia report considers demand for aviation (1,424,361 tonnes in 2050), fertiliser production (89,546 tonnes in 2050) and feedstock for steel (32,500 tonnes in 2050) to be uncertain.
Source: Oxera representation based on Castalia (2022), 'New Zealand Hydrogen Scenarios', June, p. 82, https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf (accessed 6 July 2023).

3.53 Using Castalia's base demand scenario, we calculate the stylised emissions abatement cost for a range of potential delays in the adoption of hydrogen. Our methodology is set out

[92] Castalia (2022), 'New Zealand Hydrogen Scenarios', June, https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf (accessed 6 July 2023). Note that the study does not model residential or SME use of hydrogen.
[93] Castalia (2022), 'New Zealand Hydrogen Scenarios', June, p. 55, https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf (accessed 6 July 2023).

in Box 3.2 below. In its base case, Castalia expects hydrogen demand to increase from 111,392 tonnes in 2030 to 1,889,384 tonnes by 2050.[94] This is including demand for aviation (1,424,361 tonnes in 2050), fertiliser production (89,546 tonnes in 2050) and feedstock for steel (32,500 tonnes in 2050) which Castalia considers to be uncertain. Other potential use cases that are named in the report (e.g. process heat and domestic combustion) are not modelled, and therefore cannot be accounted for in this analysis.

[94] In the high (low) demand scenario hydrogen use is predicted to be 127,982 (108,892) tonnes in 2030 and 1,987,903 (1,809,320) tonnes in 2050.

Box 3.2 Methodology

1) Based on the MBIE's hydrogen scenarios, identify the projected demand for hydrogen that would be transported through pipelines by 2050.
   We assume that all use cases except specialty and light-duty vehicles could potentially rely on pipeline infrastructure for their hydrogen demand. We model two scenarios for pipeline use: in the high-use scenario, 10% of total demand is transported through pipelines, while this share is set to 5% in the low-use scenario. We also assume that all of the hydrogen demanded will be replacing natural gas. Because we have demand data only for 2030, 2040 and 2050, we assume zero green hydrogen demand in 2023 and fit non-linear (power) growth curves (where applicable) to the available data points.
2) Create a counterfactual scenario in which the hydrogen adoption is delayed due to underinvestment in pipeline infrastructure.
   In the counterfactual, demand in year t is set to be equal to demand in year t+x of the MBIE scenarios, where we model x as a range of years between one and four.
3) For each year, calculate the energy gap in terms of kWh that results from the delay in hydrogen.
   This is done by determining the gap in hydrogen demand between the MBIE scenarios and the counterfactual and multiplying the gap with the energy content (kWh/tonne) of hydrogen.
4) Determine the amount of CO_2 emissions that would occur from producing sufficient energy to fill the energy gap through the combustion of natural gas.
   To this end, we multiply the energy gap by the CO_2e that occurs from the combustion of natural gas per kWh of

industrial use.[95] We assume that no additional emissions are produced through the distribution of green hydrogen.

5) Calculate the net present value of the abatement costs arising from the additional CO_2 emissions
The additional emissions are multiplied by the abatement costs per tonne of CO_2e.[96] We then apply a discount rate of 5%, the default rate as recommended by the New Zealand Treasury,[97] to obtain the NPV of the cost resulting from an x-year delay.

Source: Oxera.

3.54 There is a considerable degree of uncertainty with respect to i) the actual development of demand for hydrogen; and ii) the exact amounts that would be transported through pipelines as opposed to other means of transportation (e.g. trucks) or production on site.

3.55 The uncertainty with respect to hydrogen demand arises from the various interdependencies with the price of hydrogen and other energy carriers, technological developments, regulatory frameworks, policy developments and other aspects, all of which are difficult to predict but will tend to affect hydrogen's relative competitiveness and uptake in the international and New Zealand markets.

3.56 Given the uncertainties with respect to demand, it is also difficult to determine how much hydrogen will eventually be distributed via pipeline infrastructure. Where hydrogen cannot be produced at the point of use, high-quality pipeline infrastructure is likely to become an important pillar of the hydrogen economy. According to the International Energy Agency (IEA), pipelines are likely to be the most cost-effective

[95] The emissions data is retrieved from the Ministry for the Environment (2022), 'Emission Factors Workbook', https://environment.govt.nz/assets/publications/Measuring-emissions-guidance-August-2022/Emission-factors-workbook-Measuring-emissions-guidance-August-2022.xlsx (accessed 6 July 2023).
[96] We use the central shadow price of carbon retrieved from New Zealand Treasury (2022), 'Information on the shadow price of carbon (OIA-20210278)', 5 April, p. 2, https://www.treasury.govt.nz/sites/default/files/2022-03/oia-20210278.pdf (accessed 7 July 2023).
[97] New Zealand Treasury (2020), 'Discount Rates', 18 September, https://www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/reporting-financial/discount-rates (accessed 10 July 2023).

long-term choice for local hydrogen transmission and distribution over longer distances if there is sufficiently large, sustained and localised demand.[98] Pipelines can also serve as short-term storage for surplus hydrogen, to support intraday and weekly flexibility to energy and electricity systems.[99] However, many of the use cases shown in Figure 3.6 will likely rely on on-site hydrogen production. While the Castalia report suggests that at least some of these use cases will require hydrogen to be transported though pipeline infrastructure, the amount is not quantified.[100]

3.57 In the absence of predictions about the pipeline requirements of the specific use cases, to narrow down a plausible range of hydrogen that is likely to be transported via pipelines, we seek estimates of the share of gas network assets that are expected to be needed to meet hydrogen demand in other jurisdictions. We are aware of one such precedent, from the Netherlands. According to a decision by the Dutch competition regulator, it is assumed that between 5% and 10% of existing natural gas network assets will be retained for transporting hydrogen.[101] Based on these figures, we assume that 5–10% of the demand from the various use cases requires pipelines. We translate these assumptions into two stylised scenarios for pipeline use: a low- and a high-use scenario, which are set out in Table 3.1. The assumptions are likely to represent the lower end of the pipeline transport demand spectrum, given that, under its most ambitious scenario, a hydrogen feasibility study commissioned by Firstgas projects about 37% of total hydrogen demand to be transported via pipelines by 2050.[102]

[98] International Energy Agency (2019), 'The future of hydrogen', June, pp. 67–74, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdfhttps://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf (accessed 6 July 2023).
[99] Aqua Consultants and Element Energy (2021), 'New Zealand Hydrogen Pipeline Feasibility', p. 30, https://firstgas.co.nz/wp-content/uploads/Firstgas-Hydrogen-Pipeline-Network-Trial-FINAL.pdf (accessed 6 July 2023).
[100] See, for example, Figure 4.1 in Castalia (2022), 'New Zealand Hydrogen Scenarios', June, https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf (accessed 6 July 2023), p.56.
[101] Autoriteit Consument & Markt (2021), 'Methodebesluit GTS 2022-2026', para. 166, https://www.acm.nl/sites/default/files/documents/methodebesluit-gts-2022-2026.pdf (accessed 10 July 2023).
[102] Aqua Consultants and Element Energy (2021), 'New Zealand Hydrogen Pipeline Feasibility', https://firstgas.co.nz/wp-content/uploads/Firstgas-Hydrogen-Pipeline-Network-Trial-FINAL.pdf (accessed 6 July 2023). The 37% share is derived from the pipeline transport demand which is projected to be about 15TWh in 2050 (see p. 156), and the total hydrogen demand which is projected to be about 41TWh in 2050 (see p. 39). Note that the hydrogen demand modelled in this study is based on additional use cases that are not modelled in the Castalia report (e.g. domestic combustion uses).

Table 3.1 Assumptions on pipeline use

Sector	Use case	Low pipeline use	High pipeline use
Transport	Heavy-duty vehicle	5%	10%
	Coach buses	5%	10%
	Speciality vehicle	Excluded	Excluded
	Light-duty vehicle	Excluded	Excluded
	Aviation	5%	10%
Industry	Fertiliser production	5%	10%
	Feedstock for steel	5%	10%

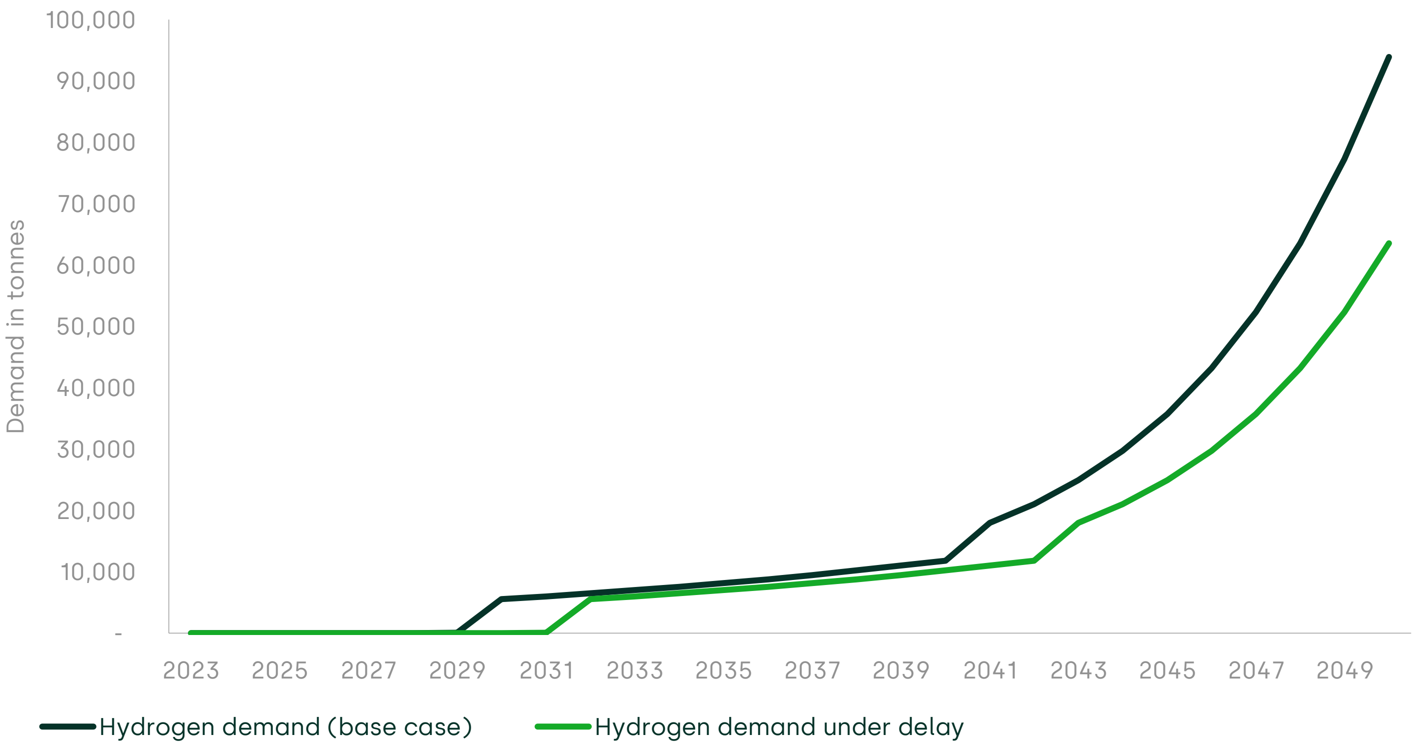
Source: Oxera.

3.58 For both pipeline use scenarios, we exclude specialty and light-duty vehicles, as depending on what these assets are, they may source fuel from alternative sources besides hydrogen—e.g. agricultural equipment may use biofuels, or light-duty vehicles may be more likely to be electrified than converted to hydrogen.[103] For all remaining use cases, we assume that the share of the demanded hydrogen that is transported through pipelines is 5% in the low-use case, and 10% in the high-use case.

3.59 As we do not have any precedents or priors to rely on in relation to how much underinvestment in pipeline infrastructure could delay the adoption of hydrogen in New Zealand, we model delays in yearly intervals up to four years. This is well within the range of connection delays that are observed internationally for other renewable energy systems (e.g. wind and solar) to electricity grids, which according to the Financial Times, varies 'from a couple of years in parts of the US to up to 15 years in the UK'.[104] Figure 3.7 below sets out the development of hydrogen demand under low pipeline use for the base demand scenario, as well as for a two-year delay of this scenario.

[103] For research into various low- and zero-carbon fuel sources in different use-cases, see Oxera (2021), 'Review of future energy mix options', Prepared for States of Jersey, 8 September, https://www.gov.je/SiteCollectionDocuments/Environment%20and%20greener%20living/Review%20of%20future%20energy%20mix%20options.pdf (accessed 11 July 2023).
[104] Mooney, A. (2023), 'Gridlock: how a lack of power lines will delay the age of renewables', 11 June, https://www.ft.com/content/a3be0c1a-15df-4970-810a-8b958608ca0f (accessed 6 July 2023).

Figure 3.7 Hydrogen demand under two-year delay



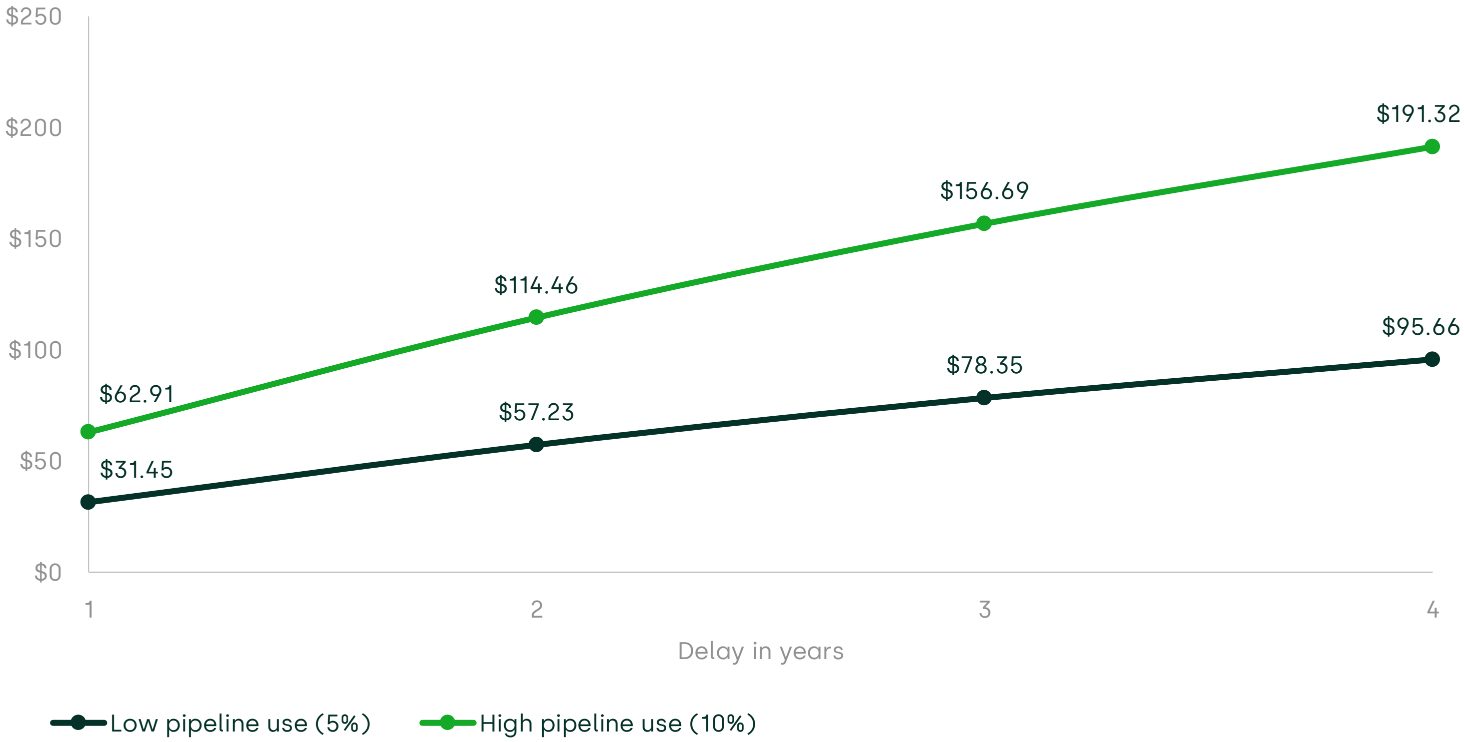
Note: Hydrogen demand under base case and under a two-year delay assuming low pipeline use (5% of total demand excluding specialty and light-duty vehicles). We assume zero hydrogen demand in 2023, and use polynomial fitting (where applicable) to interpolate between available demand data points from Castalia (2022).
Source: Oxera analysis based on Castalia (2022), 'New Zealand Hydrogen Scenarios', June, https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf (accessed 6 July 2023).

3.60 Based on the delays, we calculate the difference in served energy for each year. We assume that the gaps would be served with energy from natural gas in the counterfactual to determine the total emissions from combustion, as well as transmission and distribution of natural gas in terms of CO_2e resulting from the delay. This is likely to be an underestimate, and should be considered a conservative approach because the transport sector and steel industry rely on fuels like diesel and coal, which are more polluting than natural gas. To the extent that hydrogen use displaces such fuels, it would therefore imply higher emissions reductions.

3.61 The total emissions for each delay and pipeline-use scenario are multiplied by the shadow cost of carbon, and discounted by

5%[105] each year to get to an indicative number of the present value of the potential cost the delays may have for the environment. The results of the illustrative cost estimations are displayed in Figure 3.8.

Figure 3.8 Total cost of delays in hydrogen adoption by pipeline-use scenario (NZ$m)



Note: The presented results are based on the base scenario for hydrogen demand and the central scenario for CO_2e abatement costs.
Source: Oxera analysis.

3.62 The figure shows that for the included use-cases, even a one-year delay could result in environmental costs as high as NZ$31m in the case of low pipeline use, and NZ$63m in the case of high pipeline use. Under the high-use case, a four-year delay could result in costs of about NZ$191m, which corresponds to

[105] This is applying the default discount rate as recommended by the New Zealand Treasury (2020), 'Discount Rates', 18 September, https://www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/reporting-financial/discount-rates (accessed 10 July 2023).

about 0.17% of government revenues in 2022.[106] While many aspects around these estimates rely on stylised assumptions, they nonetheless provide an insight into the order of magnitude of potential costs arising from delays in hydrogen adoption.[107]

3.63 For comparison, we have carried out the same modelling exercise using renewable gas projections in the green gas scenario from a study on future gas infrastructure commissioned by Firstgas and Powerco.[108] While the study includes different use cases, like electricity generation and residential use, overall demand projections for 2050 are fairly similar to the base case of the Castalia study.[109] We find the resulting cost of delays to be about ten times higher than the figures presented above. This is likely because the study assumes a larger share of pipeline throughput for renewable gas by 2050 (between 93% and 97%, compared to the 5–10% we apply above).

3.64 Overall, the future demand for hydrogen is uncertain, depending on various factors such as prices and technological advances, as well as policy and regulatory frameworks. The distinct structure of the New Zealand island economy, and the abundant availability of renewable energy resources, provide the potential for renewable gases to play a role in the country's pathway to a decarbonised energy supply. We understand from Firstgas that demand for renewable gases already exists today. The use of existing pipelines can be an effective way for the transportation and storage of renewable gases, but will require continuous

[106] Overall revenues in the year to June 2022 amounted to NZ$113bn according to Inland Revenue (2023), 'Revenue collected 2001 to 2022', 3 May, https://www.ird.govt.nz/about-us/tax-statistics/revenue-refunds/revenue-collected-2001-to-2022 (accessed 11 July 2023).
[107] We also note that some potentially important use cases of hydrogen (e.g. with respect to energy and electricity system services, process heat or domestic and commercial combustion uses) are not modelled in the demand scenarios, and are therefore not included in the cost estimations but may well require additional amounts of hydrogen. Hence, even if a share of the modelled use cases does not materialise, this may be compensated by demand from other non-included use cases.
[108] Vivid Economics (2018), 'Gas infrastructure futures in a net zero New Zealand', December, https://www.vivideconomics.com/wp-content/uploads/2019/09/16098-First-Gas_Future-of-Gas-Report-Dec18-FINAL-high-res.pdf (accessed 18 July 2023). The study also includes a 'Diversified mix' scenario, in which fossil gas continues to be used in hard-to-abate sectors combined with carbon-offsetting schemes, as well as an 'All electric' scenario in which the entire energy demand is met by electricity and the use of gas is phased out entirely.
[109] In 2050, total demand, including aviation, in the base case of the Castalia report, amounts to about 1.9m tonnes, which corresponds to about 226PJ. This compares to up to 219PJ in the green gas scenario of the Vivid Economics study. See Castalia (2022), 'New Zealand Hydrogen Scenarios', June, p. 82, https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf; and Vivid Economics (2018), 'Gas infrastructure futures in a net zero New Zealand', December, p. 31, https://www.vivideconomics.com/wp-content/uploads/2019/09/16098-First-Gas_Future-of-Gas-Report-Dec18-FINAL-high-res.pdf (accessed 18 July 2023).

maintenance of the network and additional investments by network operators.

3.65 Our high-level illustrative calculations show that risking underinvestment in the pipeline network could delay the adoption of renewable gases, and result in considerable environmental costs in the order of several tens or even hundreds of millions New Zealand Dollars. These costs would be additional to the outage cost that feeds into the loss analysis framework, and should be considered for the proposed removal the WACC uplift for gas networks.

3C.3 Risk of preventing an orderly transition

3.66 A successful transition to a low-carbon future is dependent on the right timing of several factors. For instance, where processes are being electrified, the electricity network needs to have sufficient capacity as soon as consumers switch from gas to electricity. Similarly, sufficient ramp-up of renewable gas supply is required where processes are being decarbonised using gas.

3.67 A further risk that might materialise if there are insufficient investment incentives is that gas networks reduce certain investments that are required for such a coordinated transition.

3.68 In this context, we note that gas networks in New Zealand do not have an obligation to supply gas to customers—unlike in some other jurisdictions where such an obligation exists. This means that GPBs might have a low incentive to invest in maintenance or replacement of network infrastructure, and may even shut down parts of the network. This could leave businesses and residential consumers without gas supply when alternatives are not yet available. If this accelerates the electrification of certain use cases, it might also mean that electricity demand outpaces the capacity of electricity networks. This in turn could lead to network quality issues on the electricity side.

3.69 This 'unorderly' transition, where future energy plans are not coordinated due to parts of the gas network being shut down prematurely, could be a further cost to consumers that could materialise if GPBs underinvest in the network.

4 Other regulatory tools and the overall regulatory package

4.1 There are different levers policy makers can use to adjust the risks and returns of a regulatory regime, such that the right level of investment is incentivised. This section discusses regulatory tools—other than the WACC and WACC percentile—that can be used to address the asymmetry of risks from under- and overinvestment. We observe a growing base of international regulatory precedents, in relation to the tools that regulators are using in the gas sector to adjust the level of the risks to which investors are exposed. This section examines whether such tools are sufficiently used in the NZCC's DD to warrant a reduction in the WACC uplift.

4.2 In this section we examine:

- financial incentives for outputs and their potential asymmetry (section 4A);
- uncertainty mechanisms in relation to the future of gas (section 4B);
- policies to address asset stranding risks (section 4C).

4A Insufficient financial incentives for reliability and asymmetry of incentive design

4.3 When discussing the WACC uplift for EDBs, the NZCC notes that since the previous decision to set the WACC uplift at the 67th percentile, it has introduced a quality incentive scheme for EDBs. However, it does not consider this incentive scheme to be sufficient to mitigate the risk of underinvestment for electricity networks.[110] On the gas side, no equivalent incentive has been introduced, while at the same time, the WACC uplift has been removed. Thus, the regulatory regime appears to have become more asymmetric, risking underinvestment in the gas network.

4.4 In general, it appears that in the current regulatory framework enforced by the NZCC, there are little, if any, financial incentives

[110] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, para. 6.44, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).

in place for gas distribution companies that reward maintaining, or improving, the quality of service and reliability of their networks. This differentiates the NZCC's approach from that of other regulators, who often employ a mix of financial incentives and penalties to stimulate service quality and network reliability.[111]

4.5 For instance, Ofgem provides incentives for companies to outperform on a number of service quality and reliability metrics. Some of these incentives include the below.

- Consumer Vulnerability and Carbon Monoxide (CO) Safety Use-It or Lose-It Allowance: this measure provides gas distribution networks with a budgetary allowance to support consumers in vulnerable situations, and to raise awareness about the dangers of CO. However, it operates on a use-it-or-lose-it basis; if the gas distribution networks do not utilise the allowance for these purposes within a set timeframe, they forfeit it. This approach incentivises companies to actively engage in these customer support and safety initiatives.

- Customer Satisfaction Survey: this measure provides gas distribution networks with financial rewards for exceptional customer service in different operational areas such as planned interruptions, emergency responses, and connection works. The performance is gauged through customer satisfaction surveys, thus encouraging companies to strive for excellent customer experiences in order to qualify for these rewards.

- Shrinkage and Environmental Emissions: this measure aims to reduce shrinkage (the loss of gas in transit due to leaks) and associated methane emissions. This not only contributes to environmental sustainability, but also reduces the cost of purchasing replacement gas. The scheme employs a penalty-reward system: gas distribution networks that successfully lower shrinkage below the set targets receive rewards, while those that

[111] Ofgem (2020), 'RIIO-2 Draft Determinations – Gas Distribution Annex', table 2, https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/draft_determinations_-_gd_sector_0.pdf (accessed 6th July 2023).

exceed the targets incur penalties. This structure motivates companies to adopt efficient and environmentally friendly practices in their operations.

4.6 Similarly, in Italy, there are incentive mechanisms with rewards and penalties for gas leaks/dispersions and gas odorisation.[112]

4.7 In addition to incentives not being used for GPBs, it appears that there are some incentives (or licence conditions) in the regulatory regime that make the incentive structure asymmetric. An asymmetric incentive structure exists when the rewards and penalties faced by an entity for different outcomes are not balanced. Holding all else equal, this would tilt the balance of risks and rewards downwards in the regulatory system—if the downside risks are not appropriately rewarded. For instance, the service quality regime in the DPP imposes penalty-only standards. Breaching these standards can lead to court action and pecuniary penalties of up to NZ$0.5m for individuals, or NZ$5m for businesses per breach, as per Section 87 of the New Zealand Commerce Act.[113,114]

4.8 By setting the WACC above the mid-point, this acts as a countervailing tool to redress such downside asymmetry if it is present in the regulatory price control package. In effect, the higher WACC provides a financial buffer or reward that encourages companies to invest in their infrastructure and service quality, despite the downside risks associated with these investments. In the presence of an asymmetric incentive structure, unless the sources of asymmetry are redressed at source, and unless downside-only network risks are mitigated within the regulatory settlement, a WACC uplift may be required for an overall balanced system.

[112] ARERA (2019), 'Delibera 27 dicembre 2019 569/2019/R/gas', 27 December, https://www.arera.it/it/docs/19/569-19.htm (accessed 13 July 2023).
[113] Ministry of Business, Innovation, and Employment (2023), 'Commerce Act 1986', 20 April, Section 87, https://www.legislation.govt.nz/act/public/1986/0005/latest/versions.aspx (accessed 17 July 2023).
[114] The quality standards require that a GDB's response time to emergencies does not exceed 180 minutes, with a maximum of 20% of responses exceeding 60 minutes. A GDB may seek an exception if there is a reasonable excuse for not meeting the 180-minute standard, by submitting a request to the Commission within 45 working days of the emergency, supported by evidence. See New Zealand Commerce Commission (2022), 'Gas Distribution Services Default Price-Quality Path Determination 2022', section 9, https://comcom.govt.nz/__data/assets/pdf_file/0026/284525/Gas-Distribution-Services-DPP-Determination-2022-31-May-2022.pdf (accessed 17th July 2023).

4B Uncertainty over the future of gas and associated policies

4.9 The NZCC states that it cannot pre-empt national energy strategy decisions, and is not able to assess their impact.[115] One option to deal with uncertainty over future government policies is to include re-openers within the regulatory regime. This would allow the NZCC to amend allowances within the regulatory period if certain triggers (e.g. in terms of policy changes) were met. Such re-openers are being used in other jurisdictions. For example, in Great Britain where Ofgem introduced a heat policy and a net zero re-opener in RIIO-GD2[116], and in Northern Ireland where the Utility Regulator has introduced uncertainty mechanisms to release funding to enable flexibility and a degree of financeability to meet the Energy Strategy requirements.[117]

4.10 The NZCC does not consider the prospect of policy changes to warrant a re-opener within the DPP. It argues that this would reduce the incentives for regulated networks 'to improve efficiency for the long-term benefit of consumers'.[118] It also argues that the uncertainty is already somewhat being addressed by shortening the regulatory period from five to four years as part of the DPP.[119]

4.11 While we agree that a reduction in the length of the regulatory period helps to address the uncertainty over the future of gas, there is still significant short-term uncertainty. In particular, we note that New Zealand's hydrogen roadmap is due to be published in 2023, with the strategy being finalised by the end of 2024.[120] We expect this strategy would have an impact on GPBs. Not including a re-opener (in addition to removing the WACC

[115] New Zealand Commerce Commission (2023), 'CPP and in-period adjustment mechanisms topic paper', para. 6.93, https://comcom.govt.nz/__data/assets/pdf_file/0025/318625/Part-4-IM-Review-2023-Draft-decision-CPPs-and-In-period-adjustments-topic-paper-14-June-2023.pdf (accessed 6 July 2023).
[116] Ofgem (2021), 'RIIO-2 Final Determinations – GD Sector Annex (REVISED)', Table 38, https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_gd_annex_revised.pdf (accessed 10 July 2023).
[117] Utility Regulator (2022), 'GD23 - Gas Distribution Price Control 2023-2028 Final Determination Annex G Energy Strategy', October, p. 1, https://www.uregni.gov.uk/files/uregni/documents/2022-10/Annex%20G%20-%20Energy%20Strategy.pdf (accessed 11 July 2023).
[118] New Zealand Commerce Commission (2023), 'CPP and in-period adjustment mechanisms topic paper', para. 6.94, https://comcom.govt.nz/__data/assets/pdf_file/0025/318625/Part-4-IM-Review-2023-Draft-decision-CPPs-and-In-period-adjustments-topic-paper-14-June-2023.pdf (accessed 6 July 2023).
[119] Ibid., para. 6.93.
[120] Ministry of Business Innovation & Employment, 'A roadmap for hydrogen in New Zealand', https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/roadmap-for-hydrogen-in-new-zealand/ (accessed 10 July 2023).

uplift) could mean that some of the necessary investments in relation to an orderly gas transition are being delayed, e.g. until the next regulatory period.

4C Addressing asset stranding risks

4.12 Asset stranding risk for gas networks refers to the possibility of not being able to fully recover investments because of a decline in demand, driven by political decisions to reduce and potentially phase-out the use of natural gas.[121]

4.13 There are a number of levers regulators can use to address asset stranding risk. Some of these are summarised in Table 4.1.

Table 4.1 Regulatory tools to address asset stranding

Regulatory instrument	Selected examples of where this has been used	Used by NZCC according to DD?
Shortening of asset lives	Belgium, France, Germany, New Zealand (fibre)	Yes
Changing the depreciation policy	Netherlands, Great Britain, New Zealand (fibre)	No
Using an unindexed RAB	Netherlands	No
WACC uplift	Austria, France	No
Additional ex ante revenue allowance	New Zealand (fibre)	No
Policy re-openers	Great Britain, Northern Ireland	No

Source: Based on Oxera (2021), 'Regulatory tools applied to gas networks to accommodate energy transition, https://comcom.govt.nz/__data/assets/pdf_file/0016/264400/Powerco-Vector-and-Firstgas-Oxera-Energy-transition-regulation-report-Submission-on-Gas-DPP-2022-process-and-issues-paper-30-August-2021.pdf (accessed 5 July 2023); New Zealand Commerce Commission (2020), 'Fibre input methodologies: Main final decisions – reasons paper', 13 October, para. 6.984, https://comcom.govt.nz/__data/assets/pdf_file/0028/273475/ChorusE28099-price-quality-path-from-1-January-2022-Final-decision-Reasons-paper-16-December-2021.pdf (accessed 18 July 2023).

[121] Council of European Energy Regulators (2018), 'Study on the Future Role of Gas from a Regulatory Perspective ', 6 March, section 5.1.2.1, https://www.ceer.eu/documents/104400/-/-/6a6c72de-225a-b350-e30a-dd12bdf22378 (accessed 5 July 2023).

4.14 The DD states that the NZCC plans to maintain RAB indexation to account for inflation for GPBs. It argues that it does not consider that removing RAB indexation is directly relevant to asset stranding risk, as the underlying issue is demand uncertainty, rather than inflation.[122]

4.15 The NZCC also explains that it does adjust regulatory asset lives, but has rejected allowing alternative depreciation methods in default price-quality paths (DPPs), arguing that 'allowing alternative methods to straight-line depreciation in DPPs would likely add significant complexity to the DPP process'.[123] We note that alternative depreciation profiles may be available as part of the custom price-quality paths (CPPs). We also understand that networks have some control in relation to the asset-by-asset treatment in the depreciation calculation, but that for the system overall the NZCC's decision is to not introduce accelerated depreciation within the DPPs.

4.16 Finally, the NZCC argues that asset stranding risks are being addressed through adjustments to asset lives. It does 'not consider that these risks are systematic, and so they are not compensated or mitigated through the WACC'.[124]

4.17 We disagree with the NZCC that it can be assumed that decarbonisation risks, and therefore asset stranding risks for gas networks, are not, at least in part, systematic. We observe that there do appear to be causal mechanisms by which market risks can affect decarbonisation risks.

4.18 Note, for context, that upstream commodity price fluctuations that tend to increase macroeconomic stress (supply side shocks resulting in higher inflation) can in turn affect the weight that is given to decarbonisation objectives. For instance, in the current energy crisis, initial government responses have focused on

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[122] New Zealand Commerce Commission (2023), 'Financing and incentivising efficient expenditure during the energy transition topic paper', 14 June, para X16–X17, https://comcom.govt.nz/__data/assets/pdf_file/0026/318626/Part-4-IM-Review-2023-Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023.pdf (accessed 5 July 2023).

[123] Ibid., para X35.1.

[124] New Zealand Commerce Commission (2023), 'Cost of capital topic paper. Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, para. 6.103.2, https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf (accessed 5 July 2023).

affordability and security of supply, rather than decarbonisation.[125] A recent survey also found that energy professionals are prioritising secure energy in the trilemma, followed by clean and affordable energy.[126]

4.19 The fact that decarbonisation policies can be affected by macroeconomic stress suggests that decarbonisation risks are at least in part systematic.

4.20 A regulatory lever to mitigate these risks could therefore be asset beta. As long as the asset stranding risk is not sufficiently accounted for as an uplift to the asset beta, this provides an additional rationale for a WACC uplift above the 50th percentile. In the context of the NZCC DD, it is unclear whether a GPBs' uplift to the allowed asset beta sufficiently accounts for the risk of asset stranding.

4.21 Whether or not the asset stranding risk is systematic, it is asymmetric, i.e. it implies losses with greater probability than gains. In cases of asymmetry, a WACC uplift is also justified. The NZCC has, in fact, accounted for the asymmetry of the asset stranding risk in its fibre IMs and provided an ex ante allowance of 10bps on RAB:

> Compensation for Type II asymmetric risk associated with asset stranding will be provided by a combination of the following: retaining assets in the RAB in regulated markets, allowing for the possible shortening of asset lives (or alternative depreciation profiles) and a modest ex-ante allowance.
>
> **New Zealand Commerce Commission (2020), 'Fibre input methodologies: Main final decisions – reasons paper', 13 October, para. 6.984.**

4.22 We further note that there would be no double-counting if the asset stranding risk was addressed via both shortened asset

[125] For a summary of policies, see Oxera (2022), 'Stepping on the gas: European emergency measures to deal with high energy prices', *Agenda*, 30 November, https://www.oxera.com/insights/agenda/articles/stepping-on-the-gas-european-emergency-measures-to-deal-with-high-energy-prices/ (accessed 10 July 2023).
[126] DNV (2023), 'Energy security is top priority in the energy trilemma for 2023', 1 March, https://www.dnv.com/news/energy-security-is-top-priority-in-the-energy-trilemma-for-2023-240553 (accessed 10 July 2023).

lives and WACC. With shortened asset lives, networks recover their investment in the asset base faster, reducing the probability of the assets becoming economically stranded. However, the risk is only reduced, not eliminated—there is still a risk that the asset becomes economically stranded earlier than when the investment can be recovered with shortened asset lives. In its fibre IMs, the NZCC has used two instruments: shortening asset lives (or alternative depreciation profiles) and an ex ante allowance (similar to a WACC uplift) and has explicitly said that there is no double-counting.[127]

4.23 Overall, we observe that a range of tools are available to manage asset stranding risks, with the NZCC appearing, at present, to rely only on shortening of asset lives. We note that the regulatory measure of shortening of asset lives is currently being disputed in court.[128] To the extent that shortened asset lives do not fully eliminate the risk of asset stranding, we consider that it contributes to the reasons to set the WACC percentile above the 50th percentile.

[127] The NZCC states the following: 'For the avoidance of doubt, the tools in paragraph 6.22 [shortening asset lives, alternative depreciation profiles and an ex ante allowance of 10bps on the RAB] can be used as complements, and that is how we are using them here. This means that there is no 'double counting' or over-compensation to Chorus.' See New Zealand Commerce Commission (2021), 'Chorus' price-quality path from 1 January 2022 – Final decision. Reasons paper', 16 December, para. 6.22, https://comcom.govt.nz/__data/assets/pdf_file/0028/273475/ChorusE28099-price-quality-path-from-1-January-2022-Final-decision-Reasons-paper-16-December-2021.pdf (accessed 18 July 2023).

[128] Franks Ogilvie on behalf of the major gas users' group (2022), 'Notice of appeal under section 52Z of the Commerce Act 1986 in the matter of an appeal against the Gas Transmission Services Input Methodologies Amendment Determination (No.2) 2022 and Gas Distribution Services Input Methodologies Amendment Determination (No.2) 2022', 29 June, https://comcom.govt.nz/__data/assets/pdf_file/0025/288007/Major-Gas-Users-Group-Submission-on-IM-Review-Process-and-Issues-paper-and-draft-Framework-paper-Attachment-2-IM-Notice-of-Appeal-29-June-2022.pdf (accessed 5 July 2023).

5 Conclusions

5.1 This report has assessed the NZCC's DD in relation to the WACC and WACC uplift for GPBs. Our findings indicate that:

- the debt premium for GPBs does not sufficiently capture the additional financing costs resulting from the uncertainty over the future of gas—this warrants an uplift compared to the debt premium estimate that the NZCC has, at present, calibrated for the whole industry;
- the reasons for removing the WACC uplift are not sufficiently justified and the NZCC may underestimate the costs associated with reduced investment in the gas sector;
- other regulatory tools are unlikely to counteract the asymmetries resulting from the removal of the WACC uplift.

5.2 In relation to the WACC percentile, we find that the previous decision to set the WACC at the 67th percentile appears to have resulted in good outcomes for consumers. Specifically, it has resulted in the network quality improving over time, without any evidence of excessive profits being earned by GPBs.

5.3 While we agree with the NZCC that outages in the gas sector are likely to be less frequent and less costly than in the electricity sector, this needs to be considered in relation to the additional costs to consumers at a higher WACC. Since the RAB for GPBs is much smaller than in the electricity sector, we find that a WACC percentile above 50% and closer to the previously chosen 67th percentile is likely to be optimal, even under lower outage cost assumptions. This has been derived using the loss analysis framework and calibrating it for GPBs, which does not explicitly account for differences in the frequency and duration of outages.

5.4 In addition to outages, there are further costs that might be incurred if there is underinvestment in the gas network.

- Increased leakage and gas escapes leading to environmental costs associated with the released methane into the atmosphere: using shadow prices of carbon, we find that the cost that has been saved by reducing leakage between 2013 and 2022 amounts to around NZ$31m. This shows the importance of continuing to ensure that investment incentives for leakage prevention are in place to minimise such environmental costs to society.

- Decarbonisation costs of delaying the transition to renewable gas: while we recognise that there is significant uncertainty over the extent of renewable gas usage and the proportion of this that may be transported via gas pipeline infrastructure, we find that even relatively short delays that might occur as a result of underinvestment can result in high costs for consumers. For instance, we estimate the difference in net present value of saved emissions between following New Zealand's hydrogen strategy and delaying it by two years to be between NZ$57m and NZ$114m.
- Preventing an orderly transition: we note that a successful transition to a low-carbon system requires a coordinated approach among different parties. If GPBs were to underinvest, then this could lead to parts of the network being shut off prematurely. This in turn could leave businesses without a reliable energy source if alternatives are not yet available.

5.5 These costs are additional to any outage costs that are being considered as part of the loss analysis framework. Overall, this analysis suggests that there can be significant costs if gas networks were to underinvest. Using a WACC percentile above the 50th reduces the risk that the true WACC is below the regulated one, and therefore the risk of underinvestment.

A1 Annex

A1A Tax-adjusted market risk premium (TAMRP)

We note that the tax-adjusted market risk premium (TAMRP) is of specific interest to GDBs. This annex therefore repeats the TAMRP section from our report for EDBs.[129]

A1.1 In our previous report for the EDBs, we recommended that the NZCC places less weight on the TAMRP estimate from DGM and survey evidence, due to the unreliability and/or methodological flaws of these forward-looking estimation methods.[130] We also recommended placing less weight on the Siegel I model and more on the Siegel II model, given their respective assumptions on the relationship between the TAMRP and the RFR. Neither the NZCC nor Dr Lally have commented on the merits of these recommendations.

A1.2 In the rest of this section, we extend our discussions on these recommendations and show why they merit consideration from the NZCC as regards its derivation of an estimate for the TAMRP (see section A1B for the DGM and section A1C for the Siegel models). We also show that the TAMRP estimates by investment banks selected by the NZCC do not appear to fully represent the views of these institutions, based on the evidence that we have collated from the public domain, such that the data relied upon by the NZCC does not appear to be robust (section A1D). We conclude that a higher estimate of the TAMRP can be obtained by examining alternative publications by these analysts (section A1E).

A1B Use of DGM and survey data

A1.3 In our first report for the EDBs, we explained that both a DGM-based approach and collection of survey data face significant methodological limitations, and neither was used by the AER or Ofgem as direct input to their market return estimates.[131] In this sub-section, we focus on the NZCC's use of the DGM, which, based on Dr Lally's methodology, arrived at significantly lower estimates of the TAMRP than other methods did (i.e. 5.3% for

[129] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital. Prepared for the New Zealand electricity distribution businesses', 19 July, section 4.
[130] Oxera (2023), 'Review of the NZCC's WACC-setting methodology', 31 January, p. 27.
[131] Ibid.

New Zealand and 6.7% for Australia, relative to the NZCC's rounded average allowance of 7.0%).

A1.4 One common concern about the DGM is that, unlike approaches based on historical data (e.g. the Ibbotson model and the Siegel models), the DGM is highly sensitive to input assumptions that may be quite subjective, such as future growth rates over a perpetual period. Small changes in these assumptions could lead to large swings in the market return estimates, undermining the robustness of such modelling as it is applied to the estimation of this parameter.

A1.5 To test whether the NZCC's use of the DGM suffers from these issues, we have replicated Dr Lally's approach to the DGM and performed sensitivity tests on the model.

A1.6 In general, Dr Lally's approach to the DGM is heavily dependent on three input assumptions:

- the dividend yield (i.e. *D*);
- the long-term expected growth rate in dividends per share (DPS) (i.e. *g*); and
- the rate at which short-term dividend growth rates converge to the long-term *g*.

A1.7 The long-term DPS growth rate *g* also depends on the expected long-run real growth in gross domestic product (GDP), the creation of new shares, and the long-term expected inflation rate. Table A5.1 below outlines Dr Lally's choice for each of the assumptions and his reasoning.

Table A5.1 Dr Lally's configuration of the DGM for New Zealand

	Dr Lally's value/approach	Reasoning
Dividend yield (*D*)	3.3%, 3.6% and 3.9% for FY2023, FY2024 and FY2025	Bloomberg estimates for the NZX50
Expected long-run real growth in GDP	3%	Historical data and academic literature
Creation of new shares	0.01	Academic literature
Long-term expected inflation	2%	Forecasts and the Reserve Bank's inflation target
Long-term expected growth rate in DPS (*g*)	4.6%	Calculation
Convergence from short-term growth to *g*	Linear convergence	Assumption
Resulting TAMRP	**5.3%**	Calculation

Source: Lally, M. (2023), 'Estimation of the TAMRP', 10 April, pp. 19–22.

A1.8 Our analysis reveals that the TAMRP output, based on Dr Lally's configuration, is highly sensitive to the input assumptions adopted above. For example, by simply increasing the long-term expected inflation rate from 2% to 3% and holding all other assumptions constant, *g* would increase from 4.6% to 5.1%, increasing the TAMRP estimate from 5.3% to 6.2%. We note that 3% is not an unreasonable assumption, given that inflation in New Zealand was 5.4% between 1960 and 2022.[132]

A1.9 Alternative assumptions can also be made on the convergence from short-term dividend growth to *g*. While Dr Lally assumed a linear convergence, this assumption is by no means the definitively correct approach in DGM applications. If we assume that the dividend growth rate from FY2024 to FY2025 (based on Dr Lally's source, i.e. Bloomberg forecasts) stays constant before entering the terminal growth stage, the TAMRP estimate would be 6.6% when combined with the changes to inflation assumption. This is not to say that a flatline dividend growth rate before stepping into the terminal growth phase is unequivocally correct, any more than Dr Lally's linear interpolation between the two growth phases is unequivocally

[132] The World Bank, 'Inflation, consumer prices (annual %) - New Zealand', https://data.worldbank.org/indicator/FP.CPI.TOTL.ZG?end=2022&locations=NZ&start=1960&view=chart (accessed 12 July 2023).

correct. The concern that we have highlighted with this modelling is that the DGM model can be used to obtain results that vary considerably and therefore Dr Lally's estimate of 5.3% is not a robust input for the NZCC to use in its TAMRP estimation. These sensitivity tests are set out in below.

Table A5.2 Sensitivity tests on the DGM for New Zealand

	Dr Lally	3% inflation	3% inflation + alternative convergence method
Resulting TAMRP	5.3%	6.2%	6.6%

Source: Oxera based on analysis by Dr Lally.

A1.10 Similarly, for the DGM for Australia, adjusting the inflation assumption from 2.5% to 3% increases the TAMRP from 6.7% to 7.1%. Also, when alternative dividend yield forecasts for ASX All Ordinaries, which contains the 500 largest ASX listed companies, are used instead of those for ASX 200 (i.e. Dr Lally's assumption), the TAMRP further increases to 7.2%. These sensitivity tests are set out in Table A5.3 below.

Table A5.3 Sensitivity tests on the DGM for Australia

	Dr Lally	3% inflation	3% inflation + dividend yield for alternative index
Resulting TAMRP	6.7%	7.1%	7.2%

Source: Oxera based on analysis by Dr Lally.

A1.11 While we do not form a view that the alternative input assumptions shown in these sensitivity analyses are better than those adopted by Dr Lally, they are all reasonable alternatives that can lead to significantly different TAMRP estimates. These tests further validate our concern that the DGM is highly sensitive to input assumptions and is therefore less credible than the Ibbotson model and the Siegel models (within the sample of TAMRP estimates used by the NZCC), which rely on historical market returns.

A1C The Siegel models

A1.12 In our first report for the EDBs, we recommended placing more weight on the Siegel II model specification than the Siegel I model, on the grounds that the Siegel II model assumes that the expected real market return is constant over time.[133]

A1.13 As a brief overview of the relevant concerns, note that evaluating the relative merits of the Siegel I and Siegel II models requires one to take a view on the relationship between the historical TMR and the RFR. One view, corroborating the Siegel I model, is that the market risk premium (MRP, i.e. the TAMRP in the New Zealand context) is approximately constant over time and largely independent of the RFR. Another view, corroborating the Siegel II model, suggests that the expected TMR reverts to a long-term average, and that changes in the RFR are largely offset by changes in the MRP over time.

A1.14 A large body of past and more recent literature has supported the latter view, linking required returns to economic uncertainty. In this view, changes in the way in which risk is priced affect the risk-free and risky assets simultaneously. When economic uncertainty increases, there tends to be a 'flight to safety' by investors, which raises demand for the risk-free asset and lowers demand for risky assets. This reduces the yield on the risk-free asset and increases the premium required to hold risky assets.

A1.15 An example of this linkage is described in the consumption-based asset pricing model developed by the Bank of England, which predicts that consumers and investors will respond to an increase in economic uncertainty by increasing demand for risk-free assets and reducing demand for risky assets.[134] In this model, higher economic uncertainty simultaneously puts downward pressure on the RFR and puts upward pressure on the MRP, meaning that the TMR is roughly constant over time. The Bank of England model also assumes that consumers and investors care about large negative shocks as well as the local volatility of consumption and investment returns. When the distribution of expected consumption and GDP growth is more

[133] Oxera (2023), 'Review of the NZCC's WACC-setting methodology', 31 January November, p. 25.
[134] Summarised in Vlieghe, G. (2017), 'Real interest rates and risk', Society of Business Economists' Annual conference, 15 September, https://www.bankofengland.co.uk/-/media/boe/files/speech/2017/real-interest-rates-and-risk.pdf (accessed 13 July 2023).

negatively skewed and has a higher probability of extreme events (kurtosis), the MRP is higher and the RFR is lower.[135]

A1.16 Other studies have also voiced support for the negative relationship between the MRP and the RFR. For example:

- evidence previously relied on by Ofgem, from Mason, Miles and Wright (2003), proposed a methodology whereby the TMR should be assumed to be constant (implying a one-for-one offsetting change in the RFR and MRP),[136] and set in the light of realised historical real returns over long samples. The authors noted that there is considerably higher uncertainty about the true historical RFR, and the equity risk premium (ERP, i.e. the MRP), than there is about the TMR;[137]
- related to the preceding point, this academic view was supported in a later paper by Wright and Smithers (c. 2014–15), which concluded that the 'real market cost of capital should be assumed constant, on the basis of data from long-term historic averages of realised stock returns'. The authors implied a negative correlation coefficient of 1: 'It is therefore an application of simple arithmetic to conclude that, applying our methodology, the (assumed) market risk premium and the RFR must move in opposite directions: i.e., must be perfectly negatively correlated';[138]
- a similar conclusion about the relative stability of the TMR over time has been observed in the US market. A study in the USA found that the MRP is inversely related to the RFR—i.e. as the RFR falls, the MRP increases. Specifically, the authors concluded that, for the period 1986–2010, using data from the S&P 500, the coefficient of the relationship between the interest rate and the MRP was -0.79, such that

[135] Martin, I. (2013), 'Consumption-Based Asset Pricing with Higher Cumulants', *Review of Economic Studies*, **80**, pp. 750–51.
[136] The constant TMR was reaffirmed as a conclusion of the 2003 paper in a later paper in 2014–15 (cited below).
[137] Wright, S., Mason, R. and Miles, D. (2003), 'A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.', on behalf of Smithers & Co, 13 February, https://www.ofgem.gov.uk/sites/default/files/docs/2003/02/2198-jointregscoc_0.pdf (accessed 13 July 2023).
[138] Wright, S. and Smithers, A. (undated), 'The Cost of Equity Capital for Regulated Companies: A Review for Ofgem', p. 16, https://www.ofgem.gov.uk/sites/default/files/docs/2014/02/wright_smithers_equity_market_return.pdf (accessed 13 July 2023).

a 1% decline in the RFR would be offset by a 0.79% increase in the MRP.[139]

A1.17 Indeed, Dr Lally himself shares similar views to the academic literature set out above. Dr Lally has explained that:[140]

the second version [of the Siegel model] has merit independent of any historical inflation shock because it assumes that **the expected real market return is constant over time and this may be a better assumption than that underlying the historical averaging of excess returns (that the TAMRP is constant over time).** [emphasis added]

A1.18 Notwithstanding his belief that the Siegel II model might be superior to the Siegel I model due to its more realistic assumptions about the stability of the TMR, we observe that Dr Lally has still placed equal weights on both models. This is due to the statistical tests that he has performed on the historical TAMRP in New Zealand, where he was unable to reject the null hypothesis that the time series of the TAMRP have no time trend.[141] However, as he himself explained, distortion effects make it difficult to detect the downward drift in the true TAMRP from the regression tests that he undertook. It is therefore not robust to place equal weights on both of the Siegel models.

A1.19 In summary, based on the academic evidence available and Dr Lally's own commentary, it would be reasonable for the NZCC to place less weight on the Siegel I model specification and more on the Siegel II model. This would imply more weight being placed on the TAMRP estimate of 7.7% for New Zealand in Dr Lally's sample (corresponding to the Siegel II model specification), rather than 6.0% (corresponding to the Siegel I model).

A1D Broker estimates

A1.20 The NZCC has sought to support its estimate of the TAMRP by referring to evidence from brokers and analysts. These estimates are set out in Table A5.4 below. While attributing

[139] Harris, R. and Marston, F. (2013), 'Changes in the Market Risk Premium and the Cost of Capital: Implications for Practice', *Journal of Applied Finance*, **23**:1, pp. 6–7.
[140] Lally, M. (2023), 'Estimation of the TAMRP', 10 April, p. 18.
[141] Ibid., p. 27.

them to the various investment banks, the NZCC has not disclosed the original source of these estimates.

Table A5.4 TAMRP estimates used by major New Zealand investment banks

	TAMRP estimate
Craigs Investment Partners	6.50%
Forsyth Barr	5.50%
Jarden	7.00% and 7.25%[1]
Macquarie	7.50%
UBS	7.00%

Note: [1] As explained by the NZCC, Jarden use 7% company-wide and for Vector, but 7.25% for AIA.
Source: New Zealand Commerce Commission (2023), 'Cost of capital topic paper – Part 4 Input Methodologies Review 2023 – Draft decision', 14 June, Table 4.10.

A1.21 Our research reveals that, at least in some of the published equity analyst reports, some of these investment banks specify higher TAMRP estimates than those quoted by the NZCC. For example, while Forsyth Barr set out its expected TAMRP estimate at 7.50% in a recent report on Vector dated June 2023,[142] the NZCC has quoted an unreferenced 5.50%. Similarly, while the NZCC cites that UBS estimated the TAMRP to be 7.00%, UBS has stated that its estimate is 7.5% in another equity analyst report on Vector dated June 2023.[143]

A1.22 If the TAMRP estimates for Forsyth Barr and UBS are updated in line with the latest figures revealed in their respective analyst reports, the mean TAMRP estimates from brokers increases to 7.25% (assuming 7.25% by Jarden), and the median increases to 7.50% (assuming either 7.00% or 7.25% by Jarden).

A1.23 Therefore, based on the evidence available in the public domain, it is inappropriate for the NZCC to assert that the brokers' estimates support a TAMRP of 7.00%.

[142] Forsyth Barr (2023), 'Vector – Capex Funding No Easier', 15 June, p 3.
[143] UBS (2023), 'Vector – Draft ComCom report released', 14 June, p. 1.

A1E Our updated TAMRP estimate

A1.24 In line with the discussions set out in the sub-sections above, we recommend that the NZCC does not give weight to evidence from the DGM and survey-based results[144] in its estimation of the TAMRP. With respect to the Siegel models, we recommend placing more weight on the evidence from the Siegel II model and less on the Siegel I model due to the former's more reliable assumptions about the relationship between the RFR and the MRP. This means that a more reliable TAMRP estimate would be anchored on evidence from the Ibbotson model and a weighted Siegel model. Table A5.5 sets out the average TAMRP for different weight allocations between the Siegel I and II models. These updated estimates support a TAMRP estimate that is closer to 7.50% than to 7.00%. Adopting the NZCC's rounding approach would result in a TAMRP of 7.50%, which is also consistent with the broker estimates set out in section A1D.

Table A5.5 Updated estimates of the TAMRP with a five-year RFR for New Zealand

	25:75 for Siegel models	10:90 for Siegel models
Ibbotson estimate	7.40%	7.40%
Weighted Siegel estimate	7.28%	7.53%
Average	**7.34%**	**7.47%**

Source: Oxera analysis based on the NZCC's estimates.

[144] While not discussed in this section, our previous report explains the limitations of the use of survey-based evidence in deriving estimates of the TAMRP. In particular, we have explained that the respondents' answers are likely to be subject to a few behavioural biases. For more details, see Oxera (2023), 'Review of the NZCC's WACC-setting methodology', 31 January, p. 27.

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