22 January 2026

Matthew Clark
Manager Transpower and Gas
Commerce Commission
Via email: infrastructure.regulation@comcom.govt.nz

Tēnā koe Matt,

Gas DPP4 draft decision – stability as the transition becomes clearer

Powerco Limited (**Powerco**) welcomes the opportunity to respond to the Commerce Commission's (**Commission**) draft decision on the gas default price-quality path commencing 1 October 2026 (**DPP4**). This DPP reset comes at a time of uncertainty compared to previous DPP resets and presents complexity in producing a robust decision. Our response, evidence and recommendations on the draft decision are provided in the attached document. Our summary views are:

Incentivising investment in safe, reliable and affordable gas services requires DPP4 to be a package	• Gas will continue to play a critical role in ensuring a secure and least cost energy transition, but the supply and demand context has changed since DPP3. The approach to allowances and mechanisms available to GDBs need to reflect this change • Use of a weighted average price cap (WAPC) incentivises GDBs to manage volume risk. We accept this risk being placed on GDBs but the DPP4 package as currently proposed may not deliver on the Commission's affordability and security objectives. • It's essential GDBs have appropriate tools to manage that risk – allowances, uncertainty mechanisms, and maintaining flexibility in approach to capital contributions.
Reopeners with suitable criteria are a proportionate way to address uncertainty	• Current reopeners largely fit a growth scenario. The reopener criteria and thresholds do not reflect the current market dynamics and uncertainties. • Lowering the reopener threshold to $1 million and expanding the scope to include unforeseen demand declines triggered by a 'change event' would preserve the integrity of the draft decision by balancing consumer protection and GDB viability, with no upfront impact on customers • Based on our modelling, in-period adjustment mechanisms will be important to ensure stable prices and avoid the risk of price shocks to customers at the DPP5 reset.
Adjustments to allowances to enable justified investment	• While appropriate reopeners will be the critical mechanism to respond to uncertainty, we also recommend some adjustment to draft allowances in response to demonstrated investment priorities and planned activities • Our evidence demonstrates a case for adjusting draft allowances to provide for prudent, efficient and justified activities in system growth capex, ARR capex and SONS opex.

This reset has real consequences in Aotearoa's gas transition where GDBs play a part in facilitating the role of gas in Aotearoa's energy future. This reset sets a path for the longer-term transition and impacts energy affordability and security as we work towards that future state. There are aspects of the Commission's draft decision which would benefit from reconsideration to ensure consumer benefit and affordability are fully understood for this DPP4 period while acknowledging the longer-term transition.

This submission does contain confidential information, and we have marked this (in red) and provided a version with redaction for publishing. We would be pleased to discuss our submission with the Commission or respond to questions about our supporting information. If you have any questions or follow up regarding this submission, please contact Emma Wilson ([redacted]).

Nāku noa, nā,

[redacted]

Emma Wilson
Head of Policy, Regulation and Markets
POWERCO

Response to gas DPP4 draft decision

Commerce Commission

22 January 2026

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Executive summary

1. Powerco acknowledges the Commerce Commission's (**Commission**) draft decision on the default price-quality commencing 1 October 2026 (**DPP4**). We appreciate the Commission's work in providing stable regulatory settings while balancing the perspectives of consumers, gas distribution businesses (**GDB**s), other gas market participants, and the uncertainty surrounding the future gas supply and demand.

2. The Commission's DPP4 objectives are clear, to provide stable regulatory settings which support GDBs' ongoing investment in safe and reliable gas services over at least the next 20 years as gas remains an important part of Aotearoa's energy mix.[1] In an environment where the gas sector faces declining supply and an energy transition toward electrification, **gas will continue to play a critical role in ensuring a secure and least-cost transition**.

3. This is different from the DPP3 context, which assumed moderate demand growth in aggregate, yet the tools and mechanisms available to GDBs to manage this risk do not reflect the difference between DPP3 and DPP4.

4. The Commission's use of a weighted average price cap (**WAPC**) for GDBs deliberately places the incentive on the regulated business to manage volume risk. In a growing industry, regulated suppliers have an incentive to grow volumes under a WAPC.

5. In a declining industry, a WAPC has the same incentive on regulated suppliers, which is to maximise volumes through the period and into DPP5. **This is appropriate given the Commission's objective to support an affordable transition over the next 20 years**.

6. In contrast to DPP3, the Commission's package of regulatory mechanisms in DPP4 excludes growth capex and reduces connection capex requiring a significant shift in customer contributions which limits the tools available for GDBs to manage demand risk under a WAPC. This package may not deliver on the Commission's affordability and security objectives for DPP4 and over the long-term may result in:

   - Underserving customers as decision making shifts to short-term cost minimisation where demand is lower than assumed for the WAPC[2]
   - Rate shocks due to DPP5 WAPC calculations with lower forecast volumes
   - Reduced incentives to invest efficiently given limitations in tools to manage demand compared to DPP3 and, ultimately
   - Accelerating network stranding by making it harder to offset demand reduction through new connections.

7. Our concern is not about a complete overhaul of the draft settings themselves, but rather, ensuring that DPP4 package remains balanced and resilient to outcomes that may materially differ from what was envisioned when DPP4 was determined.

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[1] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, page 3-4

[2] The Commission has helpfully clarified that GDBs will need to maintain reliable supply for at least 20 more years. Minimising expenditure in the short term by over maintaining and underinvesting risks both being more expensive and less effective than prudent investment

8. We believe reopeners are a proportionate way to address uncertainties as they protect consumers from paying upfront for scenarios that may not occur, while enabling timely alignment when shocks materialise. Current reopeners largely assume growth and do not reflect declining market dynamics, for example the potential for a gas policy change to impact demand. In particular, we recommend:

    lowering the reopener threshold to $1 million and expanding the scope of a change event to include unforeseen change in revenue due to demand declines. This would preserve the integrity of the draft decision by balancing consumer protection and GDB viability, with no upfront impact on customers.

9. If demand falls significantly due to a change event such as change in government policy, for example to levels modelled for network stranding, Powerco's revenue could be materially lower (~$8 million), which risks underservicing remaining customers and exposing them to price shocks when demand is corrected for in DPP5. Being able to reflect this shift and smooth prices within the period creates more stable prices for customers which the Commission acknowledges is a factor consumers tend to value.[3]

10. While overall ICPs will decline, confirmed subdivision activity across Wellington, Porirua, Hutt Valley, Taranaki, Manawatū and Hawke's Bay shows sustained regional demand. These projects fall below current reopener thresholds but require timely investment to maintain choice and keep services affordable for customers, so we recommend some **system growth capex allowance** based on known subdivision activity as well as known renewable gas connection projects. In addition, we also recommend the following:

    a) **Increase Powerco's asset replacement and renewal (ARR) allowance** by including $2 million per year for resilience or $1 million per year with a streamlined approval (reopener) process for defined projects given these will not meet the reopener threshold.
    b) **Increase opex allowance for renewable gas investment** to at least $250,000 per year, given this will support long-term consumer interest by avoiding appliance replacement costs, and deferring electricity investment.

11. Incentives matter the most when market conditions are changing. Our recommendations ensure that investment incentives remain intact and the Commission retains appropriate oversight, ensuring that customers retain optionality in their choice of energy at affordable prices.

12. Our recommendations are modest, proportionate and take account of the Commission's decision-making principles – maintaining incentives to invest, considering the impacts on both today's and tomorrow's consumers, and managing price volatility.

13. We expand on these summary comments in the following sections.

[3] Commerce Commission, IM review 2023 Draft Decision Financing and Incentivising Efficient Expenditure During the Energy Transition Topic Paper, 14 June 2023, page 96.

1 Form of control recognising demand risk

Summary of positions – form of control recognising demand risk

- There is a rationale to retain the WAPC mechanism. To retain the incentives driven by this form of control, the package of mechanisms must remain balanced and resilient to changing circumstances
- Demand for gas on our footprint in this DPP4 period carries a significant uncertainty. Mechanisms need to be available should the period not progress as GDBs have forecast
- A full suite of tools is required to manage demand risks eg managing customer numbers through customer contributions and connection capex
- An altered uncertainty mechanism is required to prevent risk of consumer price shock due to sudden or unexpected demand changes and to protect all consumers
- Current reopeners are not fit for this type of uncertainty, and in the absence of a symmetric demand risk-sharing, revised reopener criteria is necessary
- Not adjusting the package may impact the service customers receive and result in rate shocks in future regulatory periods.

1.1 WAPC form of control only works with appropriate uncertainty mechanisms

1. This draft decision rightly prioritises stability:

   "we aim to provide regulatory stability and maintain consumer confidence, given uncertainty around the sector outlook. In aiming for stability, we recognise the value of flexibility in being able to respond to contingencies"[4].

2. But stability depends on confidence there is flexibility to respond if conditions materially change within the period. A regime where downside outcomes must be absorbed entirely by the GDB within one DPP period, can unintentionally shift decision making towards short-term cost minimisation and away from efficient investment. This is important for:
   - Resilience investment under climate uncertainty
   - Maintaining optionality for customers while future demand pathways become clearer
   - Ensuring the least cost energy transition
   - Preserving incentives to invest
   - Reducing between DPP period instability
   - Ensuring GDB viability.

3. From a customer perspective, it's about ensuring risk is manged in a way that preserves service outcomes and avoids large step changes in future periods if corrections are required. If persistent under-recovery occurs, it reduces flexibility to maintain service quality, manage risk proactively and invest ahead of emerging issues. We know consumers value price stability,[5] and certainty in fixed charges. As GDB look to manage revenue stability this could incentivise a shift towards fixed charges:

[4] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, Para 2.45

[5] This is acknowledged by the Commission: Commerce Commission, IM review 2023 Draft Decision Financing and Incentivising Efficient Expenditure During the Energy Transition Topic Paper, 14 June 2023, page 96. As well as results of Powerco consumer surveys.

“With everything rising and rising all the time I think a bit of certainty would go a long way. Like, this is what you’ll pay for 2 years guaranteed and I think people would stay or sign up because knowing what you’re going to pay is important.”
“If you can assure people that the bill is predictable and it's staying at that rate… even if they could make it for two years… that sort of security for people right now is big.”[6]

4. Powerco analysis (see section 1.2 below) show’s revenue could be approximately $8 million lower if residential demand fell to the level modelled by the Commission for network stranding, instead of our demand forecast. While this may not evidence the case for a change in the form of control, it illustrates the potential materiality of an unexpected demand shift, and a case for a targeted uncertainty mechanism to avoid consumer price shock. This type of mechanism delicately balances the decision-making factors because it:
   - Doesn’t impose any risk on today’s customers given it only comes into effect *if* an unexpected demand shift occurs, but
   - Ensures incentives for GDBs to invest remain as regulatory uncertainty mechanisms are accessible should an unexpected circumstance arise, and
   - Is low cost to administer compared to a Customised Price Path (**CPP**) process.

5. Relying on uncertainty mechanisms has been a common practice in other jurisdictions, for example, Ofgem’s final decision on RIIO-3 has provided for a significant number of targeted uncertainty mechanisms. For example: ‘decarbonisation project development UIOLI’ and ‘west import resilience project re-opener’. The gas Input Methodologies (**IMs**) do provide a range of reopeners, however the scope and thresholds require review to be fit for purpose for the types of uncertainties and reopener types for DPP4. Where the Commission has pointed (in the draft decision) to reopeners, an inability to meet the criteria means potential to deter efficient investment decisions. We identify the misalignment of thresholds and criteria in the sections below.

1.2 A demand uncertainty mechanism will avoid potential price shock

6. The reasons paper explains the decision not to introduce a new reopener to manage significant shifts in demand is due to a lack of new evidence to convince the Commission that the CPP process is not the better tool for this purpose[7]. The Commission notes that GDBs demand forecasts have been tested and accepted and as a central estimate of forecast demand they include prospects of both potential for upside improvement as well as downside risk.

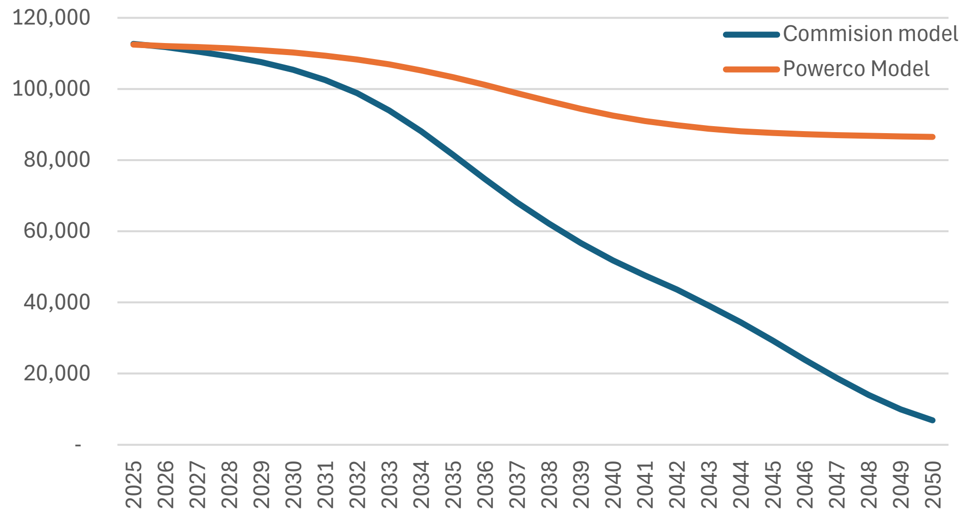
7. It’s impossible for any scenario to accurately predict what’s going to happen over a five-year period, so it is important that there are regulatory mechanisms in place to deal with the types of shocks and changes that could occur within the period. GDBs have some tools to manage within period demand risk including through prioritisation of expenditure, pricing or application for a CPP. Our experience with an electricity CPP is that this tool is very resource-intensive for both the distributor and the Commission and it is unlikely to be an efficient or proportionate way of dealing with a sudden event that GDBs need to react to (most CPP processes take roughly two years).

[6] Consumer quotes contained in: Pinstriped Leopard, *What’s fair?* Qualitative Survey Report, Residential, page 39, Accessible at ComCom-DPP4-Submissions-AttachmentD
[7] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, para 3.76 – 3.80

8. The Commission also states that GDBs can take account of variations in demand through an application for a capacity event reopener[8]. However, this reopener is only relevant where there is a need for additional capacity rather than a situation where reduced demand has changed forecast costs or revenue. This is because the reopener criteria in the IMs currently reflect a market where the potential uncertainty relates to growth, not reductions in demand, revenue or investment. The IM criteria are not appropriate for the changing market dynamics and policy environment.

9. We have modelled the potential DPP5 impact if residential demand was at the level modelled by the Commission for network stranding, compared to our modelled ICP forecast (refer Figure 1). This found that Powerco's revenue at the end of RY31 could be $8 million less than what was assumed at the start of DPP4. With a WAPC, this under recovery would be Powerco's loss, but would have impacts on how we forecast and run our business. A switch to an ICP forecast more aligned to the Commission's model at the time of the reset for the DPP5 period (RY32-36) could create a price increase of $42 per residential ICP starting at RY32. Correcting for this demand reduction in RY32 could result in a price shock of 10% in addition to any other price changes necessary from RY32.

Figure 1 Comparison of Powerco forecast residential ICPs vs Commission's network stranding model used to assess potential price shock



10. The reopeners, including those as part of the 2023 Input Methodologies review, are suitable for dealing with change events that result in additional reasonable costs or additional capacity needs[9] but are not sufficient to cover events that result in changes in allowable revenue due to factors causing changes in demand and/or supply relative to the forecasts the DPP is based on. Nor do they address reductions in demand/capacity such as a change in government policy direction leading to reduced demand or changing demand/supply context (eg implications of ban on gas exploration or ban on new gas appliances or confirmed LNG terminal). Importantly, a government election is happening just after DPP4 would have been reset, and gas policy is highly susceptible to political swings. What we don't know now is the outcome of the election or future gas policy or

[8] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, para 3.79
[9] Input methodologies as amended 13 December 2023. Part 4, definition of change event (clause 4.5.5) and capacity event (4.5.9).

the cumulative impact on public perception about gas – all clearly in the category of an change event materially beyond the control of GDBs.

11. The current $2 million threshold for reopeners is high in the context of our gas revenue and the point of change where a reconsideration of the DPP would be appropriate to protect the long-term interests of consumers and manage price volatility. A threshold of $1 million would be more appropriate.

12. We are not proposing a symmetric measure, rather a measure that will provide an opportunity to avoid a price shock at the next reset, while still incentivising GDBs to retain customers. We believe an amended reopener could appropriately mitigate the risk. If a reopener mechanism was used in this circumstance, we would expect to smooth prices for the remainder of the period, and potentially into the following period to avoid potential price shock (dependant on the timing in the period and proportionality to achieve price stability). An adjusted reopener could require this smoothing.

1.3 Assessment and recommendations – Form of control

13. A reopener process provides the opportunity for both the event and impact for both consumers and the GDB to be assessed by the Commission through that reopener process. An adjusted reopener could be an effective mechanism available which ensures that:
    - **Maintains incentives to invest at a quality consumers want** – GDBs have confidence to continue to invest in a safe and reliable network, as there is certainty that safety values are in place should sudden changes occur that weren't anticipated at the time the reset
    - **Consumers of today and tomorrow are protected** – it is in the long-term interests of today's consumers and tomorrow's consumers to ensure consumers don't pay unnecessarily upfront through allowances, for scenarios that might not eventuate. A flexibility mechanism will provide options to manage that uncertainty.
    - **Manages price volatility within the period** – provides a mechanism to manage pricing within the period and avoid a price shock at the beginning of the DPP5 period (refer section 1.2)
    - **Scrutiny at lower cost compared to CPP process** – It also allows the Commission to provide proportionate scrutiny to in-period changes, to ensure that customers are protected from inefficient expenditure, without the level of scrutiny of a CPP that may not be justified.

14. In our submission on the Issues Paper[10], we recommended a **simple adjustment to the 'change event'** provisions to include reasonable changes in revenue. We strongly recommend this change, or similar changes to **provide opportunity for a reopener related to demand reduction**, be adopted for the DPP4 period. The suggested amendment is outlined in attachment 1a. An **expectation for price smoothing** could also be incorporated in providing an adjusted mechanism. We also recommend **the reopener threshold be reset at $1 million** recognising the nature of uncertainty and need for flexibility options in DPP4. Demand risk mechanisms should also be further considered ahead of DPP5.

[10] Powerco submission on Issues Paper: available on Powerco website

2 System growth investment and customer connections

Summary of positions – system growth and consumer connection capex investment:

- There will be reductions of ICPs over time, but there will also be network growth in some areas during this period particularly new subdivisions. Our subdivision data shows a strong schedule of approved new lots and continued gas uptake in subdivisions through the DPP4 period, particularly on our financially viable (healthy[11]) networks
- Increase system growth capex allowance in the draft decision by $3.056m to account for the forecast network growth evidenced by our data
- Retain flexibility in customer contributions through higher consumer connections capex ($6.124m recommended). Mandating significant change in customer contributions is not prudent. Flexibility to enable a range of customer contribution options will provide efficiency and benefit for all customers. Consumer choice through balanced connection contributions supports energy affordability for all customers
- Reopener criteria are not fit for this type of system growth and connection capex.

2.1 Our subdivision data shows consistent forward connections

15. System growth capex relates to the development or enhancement of the network. This category of capex in our AMP is for investment driven by growth in network load which requires an increase in network capacity via network upgrade or mains extension to connect to new customers or other opportunities[12]. The key driver for this is through residential subdivision developments, with additional forecast for network extensions for renewable gas opportunities (see section 2.3).

16. Our growth capex forecast is supported by clear evidence of sustained (while regionally diverse) demand for new connections from subdivisions currently progressing on our network. We track confirmed subdivision gas enquiries expected to proceed, alongside a reasonable (but reducing) uptake in the remainder of the new housing construction market. Our AMP25 forecast connection numbers across RY26 to RY31 reflect the expectation that the market will rebound from the housing construction slowdown of the past three-years (where socio-economic indicators aligned with the downward trend in new connection numbers for both gas and electricity)[13]. There are indications of a beginning of an economic recovery.

17. Powerco has strong relationships with residential subdivision developers and a good appreciation of the expected future subdivision activity where gas connections will be part of the development. We have received commentary from developers as recently as December 2025 that there is ongoing request from buyers for gas connections[14]. Table 1 summarises our knowledge of confirmed subdivisions proceeding in the DPP4 period where we have strong confidence in gas connections based on previous stages of these subdivisions, the

[11] Powerco has undertaken a high-level assessment of the financial performance of our networks and grouped them into four categories – Healthy, Vulnerable, Industrial Vulnerable, and High Risk. This classification enables us to tailor our strategic focus to each network's specific needs, with the overarching goal of ensuring a sustainable, resilient, and customer-focused gas network. Healthy networks are which are essential to our business and to Powerco continuing to provide options for gas consumers. The assessment criteria and results are shown in Figure 2.7 of the Powerco Gas AMP 2025, page 18.
[12] Powerco Gas AMP 2025, page 190.
[13] These indicators and trends are described further in section 2.2.1 of the Powerco Gas AMP 2025, page 15.
[14] This is consistent with the evidence presented in our response to the Commission's Open Letter on the Gas DPP4 reset that residential gas appliances (primarily heating, hot water, ovens and cooktops) have a life of 15-20 years which is shorter than the Commission's forecast for gas supply availability and that the affordability of the transition depends on preserving the option for customers to use gas and avoiding the cost of premature appliance replacement.

specific developer sentiment on gas, or recent information from that developer. We have applied a 10% reduced uptake expectation from 2024 regional uptake rates to reflect some lowering of consumer gas sentiment for new connections. There are also approximately 1,000 lots in subdivisions already reticulated over the past three to four years that have been slow to sell due to the economic conditions but as conditions improve, these lots represent a near tern source of additional connections.

18. In addition to the assumed connections (Table 1), there are a significant number of further subdivisions where some uptake would occur but we have not assumed connections at this stage. These are shown in Table 1 and Figure 2 as 'other subdivisions'. For example, as recently as December 2025 the developer of a 19 lot subdivision advised that they still intend to reticulate gas, but we have not included this in our 'assumed connections' as no formal commitment has been made. There are also approximately 1,000 lots in subdivisions already reticulated in the last three to four years that have been slow to sell due to the economic conditions but as conditions improve, these lots represent a near-term source of additional connections.

Table 1 Regional subdivisions and connections

Region	Total Lots (20 years)	RY27-31 Total	Assumed % uptake (reduced rate)	Assumed Connections (RY27-31)	Other subdivisions >10 lots RY27-RY31 (uptake unknown)
Wellington	2362	366	0.86	**315**	**274**
Porirua	1750	846	0.79	**669**	**511**
Hutt Valley	1140	303	0.84	**256**	**367**
Taranaki	2505	594	0.59	**351**	**449**
Manawatu	1784	668	0.64	**428**	**484**
Hawkes Bay	220	112	0.29	**32**	**566**
Total	**9761**	**2888**		**2051**	**2,651**

19. The data in Table 1 draws on our knowledge of over 80 subdivisions of 10 lots or more currently in the pipeline or in progress. This data is tracked and we have provided a summary in attachment 2a. Additional detail in subdivisions planned/in progress can be provided if that would be helpful for the Commission.

20. Our subdivision data evidences a difference to Vector forecasting a material decline in requests for network extensions as some developers are reluctant to put gas into their subdivisions which then has longer term effects as subdivisions move into subsequent phases[15]. Vector has forecast no investment in subdivision and mains extensions from FY29 in their AMP25. The Vector data[16] for current/planned network projects for subdivisions lists a number of projects that will be completed in the DPP3 period but very few subdivision network projects that will be ongoing into DPP4.

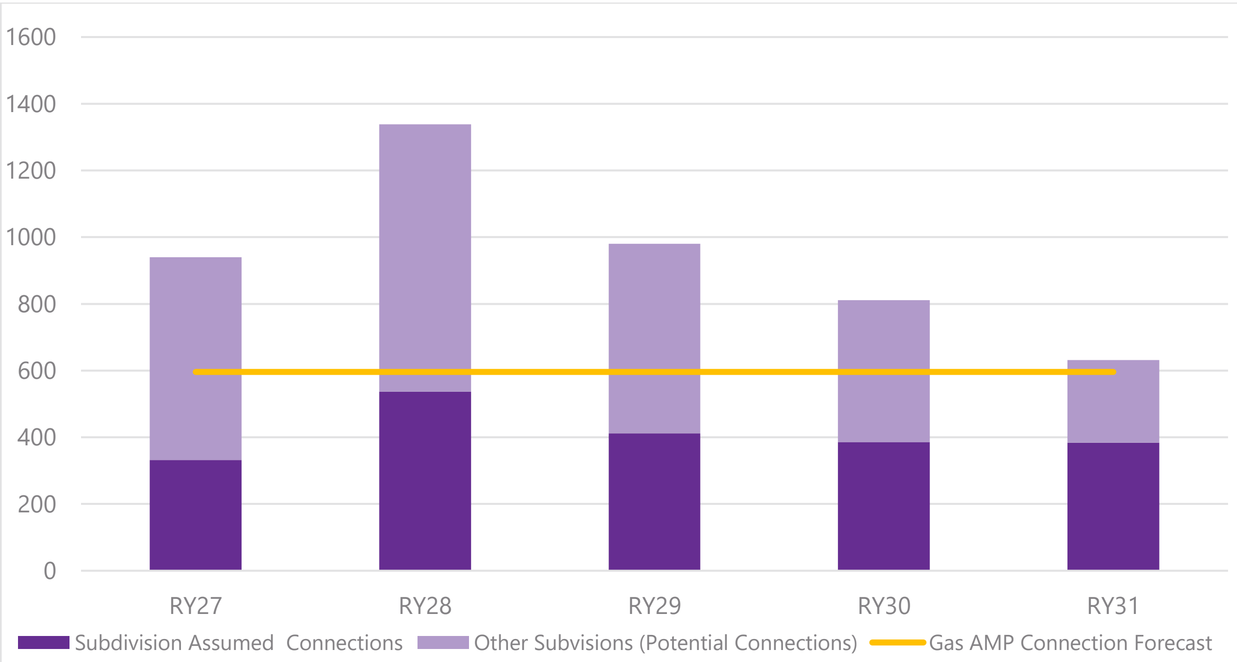
21. Figure 2 illustrates the strong forecasts for Powerco's subdivision 'assumed connections', additional potential connections from other subdivisions, and compared with the Gas AMP connection forecast. A conservative

[15] Vector Gas AMP 25 section 7.2
[16] Data: current and planned network projects-Forward Works Gas | Open Data Vector Limited

approach has been taken to assuming connections but regardless, our data provides confidence that subdivisions provide a strong source of growth. These factors provide evidence that higher growth capex is required to support prudent growth investment supporting forecast ICP connections. This capex will ensure timely delivery of new connection requests and maintain choice and affordability for customers in areas experiencing sustained development activity.

22. A capacity event reopener is not an option in these circumstances as the cost for each subdivision, or a staged subdivision within the 5 year period is well under the threshold of $2 million, generally less than $250,000. Our forecast system growth capex is reduced by capital contributions funding part of the system growth forecast, however an allowance for system growth is still required. The amount of the system growth capex proposed is $3.056 million based on:
    - Average reticulation cost based on recent subdivision projects, which vary by region. The estimated cost for the assumed subdivision connections is approximately $2.686 million, which will be partly funded by customer contributions
    - Assuming at least a small number (5%) of the other subdivisions will seek reticulation within the period which could cost $93,852 to $156,027 (depending on region)
    - Including system growth capex for renewable gas ($980,000 as discussed in section 4).

Figure 2 Forecast ICP connections from subdivision



2.2 Our approach to customer contributions is changing

23. As noted in the draft decision,
    "*new customers can provide a benefit to all pipeline users as shared costs are spread across a larger customer base. However, the benefit provided by new customers can turn on the amount of upfront contribution they pay when connecting*."[17].

[17] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, para 3.29

24. For standard residential connections, we have already been reducing Powerco's contribution and have planned a steady increase in customer contributions from RY25 to RY30, then holding constant to RY35.[18.] Calculations of commercial and industrial contributions are individually based on assessment against the principles in Powerco's Guide to Gas Capital Contributions.[19] The different methodologies for calculating customer contributions are summarised in Table 2 with more detail provided in Powerco's Guide to Gas Capital Contributions. We are satisfied that our approach to assessing the contributions for individual connections is prudent and robust, ensuring the incremental revenue exceeds the incremental cost, accounts for impact/benefit on the connecting customer and all customers, while ensuring changes to contributions are managed at a reasonable rate of change.

Table 2 Customer contribution calculations

Connection category	Factors in assessment	Powerco contribution calculation
Residential	When a new connection occurs the expected timeframe that the site remains active is aligned to the lifespan of appliances that were installed (generally 15 years)	Powerco will pay the full connection cost if the customers load places them onto a standard user tariff, if the meter is less than 20 metres to the gas main, and the connection is non-complex. Where these conditions are not met for a site (such as a site require traffic management) then Powerco has a contribution cap of $4000. Or if the 20 metres is exceeded, then a pro-rated amount above 20 metres is used as the customer's contribution.
Commercial	Commercial connections may not last the life of the appliance due a business failure or the site's purpose changing. Many variables are taken into account when connecting a new customer, such as the type of business, customer's history, network location/health and gas demand.	For standard commercial connections we have a simple calculation to ensure we recover the connection cost within a standard timeframe. This is based on our experience with commercial connection investment/cost/risk/life. This covers most scenarios, but there are circumstances that Powerco allows non-standard prices to be created for a customer. If the revenue is less than the connection cost then the customer contributes the difference.
Industrial	Industrial sites are often unique and factors will relate specifically to the type of site and business.	Industrial sites are individually priced as they are often unique and are difficult to create a standard tariff for. We also will allow commercial sites to be individually priced if there is a reason to do so.

25. Attachment 2b provides workings of our customer contribution calculations (actual examples). These show we take a prudent approach to ensure we assess cost/benefit/recovery timeframe for each type of customer. The contributions range from 0% to 100% with some cases managed through tariffs. Flexibility allows us to consider:
    - Impacts on both the current customer and future customers for the timing of contributions

[18] Powerco Gas AMP 2025, section 7.2.1.
[19] Powerco Guide to Gas Capital Contributions, Section 6.1 Principles.

- Health of a particular network, for example requiring a 100% contribution when a network has been assessed as vulnerable or high risk.[20]

26. We also have a consistent and prudent approach to calculating system growth contributions across subdivision developers (as discussed in section 2.1.) Flexibility is very important in calculating contributions for subdivision growth as this:
    - May involve a significant capex investment
    - Is a complex balance of investment, return, timing (sometimes over an extended development period)
    - Requires individual assessment (similar to industrial)
    - Will likely provide significant ongoing security, and customer price stability, for healthy networks.

27. The affordability of the transition is strongly linked to preserving the option for customers to use gas, providing consumer choice in when or what energy suits their individual situation, including the timing for when they may replace appliances. We highlighted in our response[21] to the Commission's open letter, the relevance of the life of residential gas appliances, typically15-20 years, as being a key consideration in the gas transition. This appliance life is shorter than the Commission's forecast for gas supply availability[22]. The Pinstriped Leopard consumer survey showed a strong sentiment of gas customers to stay on gas, which has also been confirmed by some retailer evidence from customers. Some retailers have also emphasised the potential for LNG to change the equation for consumers to choose the right fuel for their circumstances[23].

28. A draft decision which excludes growth capex and reduces connections capex, will likely require a significant shift in approach to customer contributions and is not prudent. We are constantly making trade-offs and using levers to manage stranding risk, prioritising customers retention, connecting new customers and ultimately ensuring customers can enjoy safe, reliable and efficient delivery of gas. The ability to adjust customer contributions is a critical tool we have to manage and respond to these risks, which are likely to change during the DPP4 period. This also allows GDBs to address unique circumstances on their different networks, which is critical when regulatory settings are locked in for five years. For example, the health of different networks.

29. Powerco's consumer connection capex has been steadily reducing since 2021.[24] Flexibility to enable a range of customer contribution options will provide efficiency in our operations and long-term benefit for all customers. With considerable uncertainty across all elements of the market (policy, demand, supply), DPP4 is about tweaks and informing DPP5 settings. Bold changes in contributions approach may have unintended consequences and prevent GDBs from fully considering both consumers of today and tomorrow. In our view the allowance for consumer connection capex in the draft decision, which is a significant reduction from our AMP25 forecast, presents a substantial shift which will force changes at a fast pace. We recommend an increase, to provide for our managed plan for customer contributions while protecting customers and managing price volatility.

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[20] Powerco has undertaken a high-level assessment of financial performance of our networks and grouped them into four categories – Healthy, Vulnerable, Industrial Vulnerable, and High Risk, refer Powerco Gas AMP 2025 Figure 2.7, page 18.
[21] Powerco response Gas DPP4 open letter, Commerce Commission, 13 March 2025
[22] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, page 3: "we see ongoing appetite for gas from households, businesses and power generation for at least the next 20 years"
[23] For example, comment made at the December 2025 Energy Trader Forum that "customers tell us that they prefer to use gas for as long as it is physically available" and retailer planning on basis that "gas is available for quite some time for small users" and that "LNG enables consumers to choose the right fuel their circumstances … and … defer new capex investment".
[24] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, Attachment B Figure B4.

2.3 Growth capex will facilitate renewable gas injection

30. System growth capex relates to the development or enhancement of the network[25]. Growth capex is also required for network augmentation to facilitate renewable gas injection (new pipe connecting our existing network to reach renewable gas opportunities). Our renewable gas expenditure is forecast for current project status and expected connection in the DPP4 period. We comment on this further in Section 4.

2.4 Assessment and recommendations – System growth capex

31. System growth capex provides the investment required to enable forecast new connections, while maintaining options for consumers through flexible customer contributions:
    - **Maintains incentives to invest at a quality consumers want** – GDBs should invest in system growth capex where this is warranted in targeted growth areas of the network. The reopener mechanism does not provide an option to assess additional investment confirmed in-period. Therefore, customer contributions will need to cover some of the forecast investment.
    - **Consumers of today and tomorrow are protected** – It is in the long-term interests of both today's and tomorrow's consumers to ensure the cost burden is spread over the declining customer base. Flexibility to manage those costs on a connection or local network basis ensures full assessment and transparency in decisions on how costs are recovered. Requiring 75 – 100% customer contributions is removing customer choice and likely to quickly reduce customer numbers causing a greater impact for consumers of tomorrow.
    - **Manages price volatility within the period** – Retaining an allowance for system growth for new subdivisions, along with flexibility in customer contributions provides a mechanism for steady, predictable and transparent pricing.

32. We recommend **adjusting the draft decision to provide allowances**:

Category	Description	Draft decision	Proposed allowance	Difference	Justification
System growth capex	Providing for network assets in new growth areas and renewable gas injection	$0	$3.056m	$3.056m	Subdivision pipeline, refer section 2.1 Renewable gas programme, refer section 4
Consumer connection capex	Providing our pathway to increase customer contributions but retain flexibility for targeted assessment alongside standardisation for efficiency	$3.062m	$6.124m	$3.062m	Robust calculation approach to balance customer impact, return timing, network health and other bespoke considerations. Refer section 2.2

[25] See paragraph 15 for explanation of system growth capex categorisation, also described further on page 190 of Powerco Gas AMP 2025.

3 Resilience capex investment in asset replacement and renewal

Summary of positions - resilience capex investment:

1. Our approach to climate risk assessment and response is based on recognised business standards (eg XRB). We have developed this approach in line with our electricity business and to inform prudent investment justified by robust assessment
2. The need for ongoing investment in network resilience and planning for climate adaption has been highlighted in the recent letter from the Minister of Energy to EDBs
3. Forecast investment for resilience during the period will be confirmed as individual project business cases are developed. A process to confirm the risk/cost/value of projects could be established through the period, but relying on the currently available resilience reopener will not be workable
4. Our ARR forecast, excluding the resilience forecast, is not increased but is forecast to be steady. A more significant reduction in ARR will not occur while we plan with the 'global alignment' climate scenario.
5. The resilience component has minimal impact on pricing
6. Our ARR capex should include an allowance for resilience of $2m per year, or a lower allowance with an alternative reopener-type process as we verify specific project resilience investment within the period.

3.1 Our capex investment in resilience is based on robust assessment and long-term consumer interest

33. We acknowledge the Commission's assessment of our ARR spend, and in particular the relationship between ARR capex and opex, as GDBs move to a greater reliance on opex to defer or reduce ARR capex requirements.

34. Climate-related hazards are no longer low-probability events. They are increasingly foreseeable risks that can be cost-effectively managed through targeted, proactive investment. Resilience ARR capex delivers value to customers by reducing the likelihood, scale, and duration of supply disruptions, while avoiding significant restoration costs and safety risks that would otherwise be borne by customers and communities.

35. Our approach to identifying and responding to climate risks is based on the accepted Climate Standards for business's approach to climate risk (issued by the External Reporting Board XRB), and our own business strategy to ensure a sustainable energy transition that helps New Zealand grow and thrive as it meets its net-zero target. This means ensuring energy remains affordable for our customers, is resilient in the face of weather events, and provides security of supply to communities.

36. The Minister of Energy has also emphasised the importance of investment for network resilience:

    "Most of those EDBs subject to price-quality regulation have historically met quality standards, but the increasing frequency and severity of weather events pose a growing risk of outages. This highlights the need for ongoing investment in network resilience and planning for climate adaptation in a changing climate" [26]

37. Powerco's adaptation and resilience strategy focuses on mitigating climate-related risks. This involves assessing the vulnerability of our gas network infrastructure to inland flooding, coastal inundation and other geohazard issues. A network-wide modelling exercise was completed in 2024 to identify critical above-ground assets susceptible to flooding and sea level rise. Special crossings, such as bridge-mounted pipelines on state

[26] Minister of Energy, Letter to EDBs, 6 October 2025

highways, and district regulator stations (**DRS**) were a key focus because of their exposure risk and role in maintaining critical gas supply. Assets located on long-span river bridges were identified as particularly vulnerable to extreme weather events and associated debris. Our vulnerability assessment found 46 DRS (24% of asset class) were exposed to physical hazards and 10 special crossings (3%) face increased exposure. The results are summarised in attachment 3b.

38. Forecast investment for resilience projects will be confirmed as individual project business cases are developed following planned investigation. A summary of the current projects, investigations, timing, solutions and estimated capex costs are summarised in attachment 3b. For description of case studies relating to potential solutions refer to attachment 3a.

39. The Hawke's Bay special crossings (refer to attachment 3a) provides a clear illustration of the value of the identified risk and the cost/benefit of assessing and managing foreseeable risks. It is estimated restoring supply from the Clive Bridge isolation valve would require [redacted] Using current restoration benchmarks, this equates to an estimated direct restoration cost of approximately $300,000 per event simply to relight the network, plus additional costs in an event response. Following a major flood, reinstatement is expected to take [redacted] under standard resourcing assumptions and could [redacted] where resources are constrained or coordinated through lifeline groups. A [redacted] outage would cost $1.2 million more than the current project underway to strengthen the Ngaruroro bridge costed at $1.11 million. Extended outages materially increase safety risk and customer impacts, particularly if electricity supply is also unavailable.

40. The Hawke's Bay Special Crossings case study 1 (refer attachment 3a), demonstrates the need for continued proactive investment to maintain gas pipeline services at a standard that consumers expect while demand for gas remains. The three strategic crossings at Clive form part of the primary supply route to approximately 3,100 customers, including six major customers across the Napier region. These assets are critical to maintaining system reliability and supply continuity.

41. In our 2025 Gas AMP, we have forecast ongoing investment of $2 million per year in adaptation and resilience (ARR) over the 10-year period. This investment is targeted at reducing the likelihood and impact of major disruptions caused by climate-related events. The additional cost to recover this investment is expected to be around $18 per customer per year for the DPP4 period, approximately $1.50 per month. Proactive ARR avoids much larger costs that would otherwise arise from asset failures, extended outages, and emergency restoration following major events, potentially creating a sharp, unanticipated cost increases that would ultimately be borne by consumers through future prices. Table 3 breaks down the additional cost to customers across the investment period.

Table 3 Additional cost to customers with $2m resilience investment per year

	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Yearly	$17.84	$17.89	$17.95	$18.04	$18.14	$18.28	$18.47	$18.70	$19.01	$19.36
Monthly	$1.49	$1.49	$1.50	$1.50	$1.51	$1.52	$1.54	$1.56	$1.58	$1.61

42. The robust assessment of risk and identification of priority resilience projects has not, as far as we are aware been undertaken by other GDBs. This distinguishes Powerco in our ARR forecast and justified allowances. Our difference does not mean that because we have proactively undertaken this targeted assessment, that this investment to maintain customer quality is not prudent.

43. Our priority resilience investment for the four priority projects is well within the full resilience programme forecast (refer attachment 3b). Should the Commission determine that the full forecast is not justified, we encourage an allowance to cover our identified priority projects plus an assumption or process for the outcome of the feasibility studies to be completed in RY26 for 2 bridges and the 46 DRS. As a minimum, an allowance of $1 million per year is prudent and justified, with any additional to be considered through a (modified) reopener process as discussed in the following section.

3.2 The resilience event reopener threshold is too high for these projects

44. The reopener threshold does not align with the scale of our resilience projects which are well under the $2m threshold. As identified in attachment 3b, project costs for our four most significant projects are likely around $1 million each based on our experience with the Ngaruroro bridge project estimated at $1.11 million. While the original driver for this project in 2022 was asset condition, the risk profile materially increased following Cyclone Gabrielle in 2023, which caused the failure of a nearby bridge-mounted gas pipeline crossing the Tutaekuri River due to flooding and slash impacts. Refer to attachment 3a for the Tutaekuri River crossing case study.

45. Despite the Tutaekuri project addressing a strategic asset, responding to climate-driven risks, and delivering resilience benefits, the total investment remains well below $2 million. This is typical of resilience projects, which often involve targeted works rather than large-scale renewals. We do not consider it would be efficient or benefit our customers if Powerco expends resources applying for reopeners for individual resilience projects, given that we have already undertaken the vulnerability assessment, and are in the process of individual business cases for each project to determine the most favourable option.

46. Should the Commission conclude that a reopener process (or similar) is appropriate to scrutinize the cost/benefit of individual resilience projects rather than approving capex allowance, for this to be workable over DPP4, two tweaks are required:
    - Lower the resilience event reopener threshold (maximum of $1 million) and
    - Provide a streamlined reopener-type process for approval of the works programme based on business case assessment.

47. As an example for the second measure, we point to the Transpower deliverability mechanism with a process for Transpower to submit FTE numbers to demonstrate deliverability on an annual basis and a streamlined 'reopener' assessment and response.

3.3 Excluding resilience, our ARR is not increasing but is important to maintain quality

48. A declining number of ICPs over time, does not correlate with declining network length or reduced assets requiring ARR. As noted in the draft reasons paper,
"unlike new ICPs which may arise from connection of new subdivisions and industrial parties and add to network length, a reduction in ICPs won't necessarily result in a reduction in network length. This is particularly

so at the early stages of a transition off gas networks when disconnections may be occurring in an uncoordinated way"[27].

49. Figure 3 shows the level of resilience investment and the reduction in overall ARR expenditure excluding the resilience component of ARR. Our base ARR is stable or declining when assessed on a historic like-for-like basis. The observed increase in total ARR reflects deliberate and targeted resilience investment to manage recently identified climate risks and protect long-term service, rather than growth in traditional ARR.

Figure 3 ARR forecast in constant figures

50. Historical ARR expenditure continues to fund core ARR activities. These activities are consistent with historical investment patterns and are required to maintain the safety and integrity of the network for the next 20 years:
    - Replacement and removal of pre-1985 and steel pipes
    - Renewal of ageing regulator stations
    - Replacement of the pressure logger fleet
    - Renewal of cathodic protection systems (CPS).

51. In line with our volume to value strategy, our ARR budget is more targeted towards maintenance on our healthy networks. For example, in RY26 our works programme will see 47% of our ARR expenditure on the Hutt Valley and Porirua networks, focusing on reliability projects on this healthy network.

3.4 Assessment and recommendations – ARR capex

52. Providing for ARR capex to maintain our network quality and deliver priority resilience projects:
    - **Maintains incentives to invest at a quality consumers want** – Maintaining the ARR forecast enables timely remediation of high-risk assets before failure occurs. This supports ongoing service quality,

[27] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, para 3.51

safety, and reliability, rather than deferring investment and increasing the likelihood of disruptive, emergency-led responses. The case study illustrates that sustained ARR investment remains necessary to operate and maintain the network at an acceptable standard for current consumers. Refer section 3.1 for more information.

- **Consumers of today and tomorrow are protected** – The case studies highlight the importance of balancing cost impacts between current and future consumers in the context of a declining customer base. Maintaining the ARR forecast supports early intervention that avoids transferring higher, more volatile costs to a smaller future customer base. A four-week outage alone would exceed the $1.11m proactive investment already approved for the Ngaruroro Bridge strengthening, demonstrating that deferral would result in poorer intergenerational outcomes. Spreading prudent investment costs over the remaining life of the assets benefits all consumers, rather than exposing future consumers to higher failure-driven costs.
- **Manages price volatility within the period** – Maintaining the ARR forecast supports early intervention that avoids transferring higher, more volatile costs to a smaller future customer base. A four-week outage alone would exceed the $1.11m proactive investment already approved for the Ngaruroro Bridge strengthening, demonstrating that deferral would result in poorer intergenerational outcomes.

53. We recommend **adjusting the draft decision to provide allowances**:

Category	Description	Draft decision	Proposed allowance	Difference	Justification
ARR - resilience	Providing for resilience projects	$0	$10m	$10m	Robust assessment and business cases for priority resilience projects, refer section 3.1
ARR – other	Traditional ARR	$28.246m	$28.246m	-	No change

4 Renewable gas investment

Summary of positions - investment for renewable gas in our network:

- Powerco has confidence that biomethane will be injected into our network during the DPP4 period. Our programme provides detail on the project pipeline, with one project well advanced
- For our regulatory business, the programme will require both opex and system growth capex investment. This will not meet the criteria for a reopener
- We are developing a more structured approach to quantify the value of renewable gas to both our regulated gas network and regulated electricity network, however the value for customers in pursuing biomethane options in our gas network is clear
- The government has supported biomethane options in the *Government Statement on Biomethane*
- Minimum allowance for biomethane opex should be $1.25 million and system growth capex $980,000.

4.1 The DPP4 period will involve both investigations and operational projects

54. The Commission has confirmed allowances in DPP3 and in the draft decision for DPP4 for investigating alternative gases that may prolong the use of the pipeline networks, noting that "maintaining this allowance for those GPBs who have clearer programmes for continued alternative gas investigation will enable them to continue trials to inject alternative gases where it is economic to do so"[28].

55. Biomethane projects work through a number of investigation and decision stages prior to proceeding to procurement, construction and operation. The initial project stages and indicative investigation cost per project is outlined in attachment 4a. Following the investigations period of DPP3, we expect renewable gas investment in DPP4 to involve further project investigation plus the first project constructed and injecting into the Powerco network. Three key projects that Powerco will advance in DPP4 are outlined in Table 4. There may also be other projects commenced later in the period or projects advanced by other parties that will inject into the network.

56. [redacted]

57. Powerco's biomethane projects involve activities that are both unregulated and regulated. As an example, the activities in the Manawatu District Council project and their regulatory status are outlined in attachment 4a.

[28] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, para 3.47

Table 4 Powerco renewable gas projects to progress in DPP4

[redacted]

4.2 Biomethane options are in the long term interests of all consumers

58. The contribution of renewable gas investment to consumer affordability occurs through avoided costs of electricity network upgrades[29]; avoided consumer costs of appliance switching; and customer retention through maximising the use of existing infrastructure, providing an ongoing reliable supply option and supporting customers looking for lower emissions energy options.

59. The Castalia report[30] on the impacts of switching off the gas network presents economic analysis of a scale of cost savings from continued use of gas networks and appliances, which biomethane options support. The analysis found that the switch-off scenario is more expensive that continuing with BAU, with the bulk of costs falling to consumers. With constant energy prices, switching off the gas network increases consumer costs[31] by $1 billion over a 25-year forecast period, a 45% rise compared to BAU. In the three regions studied, an increase in peak electricity demand of around 9% is estimated to cost $154 million, also ultimately falling on consumers.

60. Supporting expenditure on renewable gas provides a key customer benefit of maintaining optionality and choice - as gas has always been, and should continue to be, an alternative to other energy sources. The choice

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[29] For example, the Wellington Electricity AMP25 identifies the potential transition to electricity would have a significant impact on the demand on WELL's network including from 65,000 properties with a gas connection. WELL's network is designed and operated in a manner reflecting the prevalence of gas as a residential fuel. "Continued use of the existing gas transmission and distribution networks maximises the value to the community of those existing assets while delaying some of the capital expenditure required to reinforce the electricity distribution network to support the electrification of heating for a significant proportion of WELL's customers" Potential LV reinforcement capex to 2050 is $368m in response to a rapid EV uptake alongside a rapid gas transition. Wellington Electricity AMP 2025 (page 49-51)

[30] Castalia report to GIC, Switching off the gas distribution network: Consumer, network and emissions impacts, October 2025. Accessible here: Research and Analysis - Gas Industry

[31] The costs to consumers include switching rectification, appliances and installation, maintenance and energy price.

that gas provides was a key theme in residential consumers attitudes towards gas in the 2025 Pinstriped Leopard consumer research – "It's good to have choice of energy. I don't like having all my eggs in one energy basket"[32]. Consumer choice is also a key driver in prudent investment in system growth capex (refer section 2).

61. In October 2025, the Government released the *Government Statement on Biogas*[33] which 'signals our commitment to supporting the development of a domestic biogas market' and recognises that 'New Zealand is at a pivotal moment in our energy journey with our natural gas reserves declining. Biogas presents a strategic opportunity for New Zealand'. The Statement identifies three strategic opportunities: energy resilience, economic development and innovation; and decarbonisation of hard-to-electrify industries.

62. Powerco is currently undertaking work with Blunomy to develop a more structured biomethane benefits assessment framework. The Blunomy study (November 2025) examines how gas networks in other jurisdictions assess renewable gas impacts and demonstrate value. Blunomy conducted a comprehensive market scan of biomethane benefit assessment methodologies in five markets looking at key drivers of biomethane uptake, how benefits of biomethane are articulated, and the allocation of regulated and unregulated project components.

63. Some excerpts from the Blunomy findings are provided in attachment 4b. There were 5 key insights:
    - Networks align around three complementary narratives for renewable gas benefits:
        - Stranded asset mitigation
        - System-wide decarbonisation at lower cost
        - Socioeconomic value creation
    - Across jurisdictions, the same drivers have prompted networks to support biomethane development:
        - Energy security concerns from declining gas supplies
        - Climate policy and decarbonisation targets
        - Support for rural economic development
    - Regulatory appetite for including biomethane capex in the RAB correlates strongly with national energy security priorities
    - Networks in mature biomethane markets have developed system planning tools to optimise the economics of biomethane integration at scale
    - Biomethane assessments align with network ownership structures.

64. The Blunomy study provides strong international evidence for the link between biomethane projects and whole of network benefits, demonstrating benefits to all consumers on the network. Drawing on the insights, Powerco is working with Blunomy to develop a structured valuation framework to assess renewable gas investments, in order to more fully demonstrate the net value of renewable gas projects at a system level. Powerco's commitment to a role for renewable gas and quantifying the value, sits alongside our strategy to assess network health to inform network planning and rationalisation in the DPP4 period.

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[32] Pinstriped Leopard consumer engagement research July 2025, provided as part of the GIFWG submission on the Issues paper, residential report page 4 and page 16.
[33] Government Statement on Biogas.pdf

4.3 Costs are clearer and the reopener criteria not appropriate

[redacted]

[redacted]

67. In the draft decision, the Commission decided to maintain opex allowances for investigating alternative gases at the same level as DPP3 for Firstgas and Powerco as those allowances have 'incentivised GPBs to undertake alternative gas investigations that may prolong the use of the pipeline networks'.[34] However, the Commission is 'not satisfied there is a case to provide an additional allowance above our DPP3 amount'.[35] The draft opex allowance for blended gas investigation for Powerco is $56,000 per annum.

68. In our response to RFI2, we signalled that we had managed within regulatory allowances for our spend in DPP3 by adjusting opex allocations for RY24 to RY26 to enable a higher spend on renewable gas investigations opex than $56,000 while meeting our allowance overall[36]. The DPP3 allowance based on RY23 estimates is significantly below the level of investment in project investigation phases now completed or in process. For the DPP4 period, continuing with renewable gas investigations for our Taranaki and Hawke's Bay projects would be significantly restricted with a reset allowance at $56,000 per annum, and would not enable any other projects to be considered. Based on our knowledge now of actual investigation costs (attachment 4a), part allocation of costs to the regulatory business, and the projects/timing for investigation from RY27, an opex allowance of $250,000 per annum is recommended to ensure investigations can continue efficiently and we can strive to achieve the consumer benefits that are available with renewable gas – maintaining the pace already underway.

4.4 Assessment and recommendations – renewable gas

69. Allowances for system growth capex and opex for renewable gas:
    - **Maintains incentives to invest at a quality consumers want** – A future network operating with blended gas, or 100% biomethane in some locations, is a future we are confident will emerge in DPP4. This future is a strong incentive for GDBs to invest in maintaining the network at the quality consumers expect today and will expect in the future.
    - **Consumers of today and tomorrow are protected** – Our renewable gas investment is clearly targeted at providing a future for the gas network so consumers of today retain energy choices and New Zealand's energy system of the future manages the energy transition in a secure and affordable way.
    - **Manages price volatility within the period** – The Commission has accepted some opex investment for renewable gas investigations is prudent and efficient. Capex investment related to renewable gas is

[34] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, para 3.47
[35] Commerce Commission, Gas DPP4 reset 2026, Draft decision reasons paper, 27 November 2025, Attachment C para C56
[36] As noted in our response to DPP4 RFI2, 16 May 2025.

in accordance with the purpose of system growth capex. We now have confidence on the types of investigation investment, capex costs and the projects that will be active within the DPP4 period. This provides the opportunity to adjust allowances in line with the investment needed to ensure prices are managed within the period.

70. We recommend **adjusting the draft decision to provide allowances**:

Category	Description	Draft decision	Proposed allowance	Difference	Justification
System growth capex	Providing for renewable gas network projects	Refer section 2.4. This includes $980,000[37] for renewable gas capex.			Renewable gas programme, refer section 4.1
SONS opex	Providing for regulatory allocation of investigation costs	$280,000	$1,250,000	$970,000	Renewable gas project stages and programme, refer section 4.1

[37] This is based on $480,000 for the Manawatu project in RY27 and an estimate of $500,000 for a second project across RY29 and RY30.

5 Corrections and minor matters

71. Powerco has identified what appears to be an inconsistency in the Commission's financial model relating to calculation of depreciation on additional assets, as it does not appear to reflect how the asset lives are adjusted in practice.

72. On the RAB tab of the financial model, the "years of remaining life" for additional assets in the DPP3 years prior to 2027 are calculated as:
    - 45 years × DPP3 adjustment factor (0.839 for Powerco) = 37.75 years.

73. However, from 2027 in DPP4, the "years of remaining life" for additional assets is calculated as:
    - 45 years × DPP4 adjustment factor (0.692) = 31.14 years.

74. When accelerated depreciation was implemented in Powerco's systems in 2023, the IM remaining useful life (for example, 45 years) was adjusted by the DPP3 factor (0.839), such that the useful life of existing assets in the asset register became 37.75 years, less any years elapsed since commissioning. There was also a requirement to apply this same adjusted useful life to newly commissioned additional assets. As a result, additional assets commissioned during DPP3 have a theoretical useful life of 37.75 years in our asset register. At the start of DPP4, the theoretical useful lives used for both existing assets and additional assets are therefore aligned at 37.75 years, with the only difference being the number of years already elapsed for existing assets.

75. To apply the further acceleration of depreciation in DPP4, the DPP4 adjustment factor (0.692) is applied to this aligned starting point. This results in an average starting useful life for existing assets of:
    - 37.75 years × 0.692 = 26.13 years.

76. The requirement for additional assets to use the same useful life as existing assets continues to apply in DPP4 (and would be difficult to implement in practice if different). Accordingly, additional assets commissioned in DPP4 would also have a theoretical useful life of 26.13 years.

77. To better align the financial model's depreciation of additional assets with this practical application, we consider that the formula used to calculate the "years of remaining life" for additional assets in DPP4 should be:
    - 45 years × DPP3 adjustment factor (0.839) × DPP4 adjustment factor (0.692) = 26.13 years.

Attachment 1a IM amendment for change event

Proposed IM amendment

4.5.5 Change event –

(1) A 'change event' occurs where there is a change of the type described in subclause (2) or (4), the effect of which is not explicitly or implicitly provided for in the DPP.

(2) The first type is a change in a regulatory or legislative requirement that applies to a GDB as a result of new or amended legislation, or judicial clarification of the interpretation of legislation, that-

(a) results in additional reasonable costs (whether capex, opex, or both) **or causes a change in revenue** to respond to the changed requirement that exceed the relevant threshold specified in subclause (3); or

(b) causes an input methodology to become incapable of being applied.

(3) For the purposes of subclause (2)(a), the thresholds are-

(a) $100,000 for GasNet Limited; and

(b) **~~$2~~ $1**million for any other GDB.

(4) The second type is a change in a requirement that applies to a GDB under GAAP, that-

(a) results in a change in the recognition or measurement (including timing) of 1 or more of the following: (i) opex; (ii) capex; (iii) assets; (iv) liabilities; (v) allowable notional revenue; or (vi) taxation, including deferred tax; and

(b) if in effect at the time the DPP was determined, would have caused the aggregate amount of the allowable notional revenue for all disclosure years of the DPP regulatory period to have differed by an amount that exceeds the relevant threshold specified in subclause (5).

(5) For the purposes of subclause (4)(b), the thresholds are-

(a) $100,000 for GasNet Limited; and

(b) **~~$2~~ $1**million for any other GDB.

Attachment 2a Subdivision forecast data

[redacted]

[redacted]

[redacted]

Attachment 2b Customer contribution calculation workings – example cases

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Attachment 3a Resilience project case studies

1.1.1 Case study 1: Hawke's Bay Special Crossings – value of proactive investment case study

Three strategic gas special crossings located in Clive, south of Napier, form part of the main supply feed to approximately 3,100 customers, including six major customers, across the Napier region. As identified in the Climate Adaptation & Resilience Plan, all three crossings are exposed to similar climate risks, including inland flooding with return periods of approximately 1-in-20 to 1-in-60 years, and longer-term coastal inundation under SSP1-1.9 scenarios. Each crossing is supported on a bridge structure vulnerable to failure or loss during a 1-in-60 to 1-in-100-year flood event. The climate risks for these special crossings made them a high priority for remediation within the next planning cycle.

The failure of any one of these crossings would result in the loss of gas supply to approximately 3,100 customers, including six major customers across the Napier region. Based on Gas Operations Network Sector Isolation Guideline Standard (394S118), restoring supply from the Clive Bridge isolation valve would require [redacted] Using current restoration benchmarks, this equates to an estimated direct restoration cost of approximately $300,000 per event simply to relight the network.

This figure excludes a range of additional costs that would be incurred in a real event, including emergency traffic management, restricted bridge access, contractor mobilisation delays, specialist equipment, and cost escalation under adverse weather conditions. As a result, the total cost could significantly higher.

Restoration timeframes are also material. Following a major flood, reinstatement is expected to take [redacted] under standard resourcing assumptions and could [redacted] where resources are constrained or coordinated through lifeline groups. A [redacted] outage would cost $1.2m more than the current project underway to strengthen the Ngaruroro bridge approved at $1.11m. Extended outages materially increase safety risk and customer impacts, particularly if electricity supply is also unavailable. For many customers, gas supports essential needs such as heating, cooking, commercial operations, and critical services during emergency conditions.

1.1.2 Case study 2: Georges Drive DRS

Georges Drive DRS experienced flooding during a recent severe rainfall event, resulting in water ingress to the station compound and damage to electrical and control components. While gas supply was ultimately maintained, the event required urgent response actions, asset inspection, clean-up, and component replacement to restore the station to a compliant operating condition.

Post-event remediation works focused on relatively low-cost measures, including improved drainage, raising vulnerable components, sealing of cabinets, and targeted flood protection enhancements. These measures significantly reduced the likelihood of repeat damage from similar events and were delivered at a cost materially lower than full station relocation or major structural upgrades.

This event demonstrated that flood-related impacts at DRS sites can occur under current climate conditions and that reactive response carries both direct repair costs and heightened operational risk during severe weather events.

1.1.3 Case study 3: Cliff Road DRS

Cliff Road DRS also experienced flooding during a significant rainfall event, resulting in damage to station equipment and requiring unplanned repair works to reinstate the asset. While the immediate damage was addressed, the event confirmed that the station is exposed to repeat flood risk and that reactive repairs alone do not provide sufficient long-term protection.

As a result, further work is planned in FY2026 to modify the station to improve flood resilience. This work will build on post-event learnings and is expected to include targeted measures such as elevation of critical equipment and enhanced protection of electrical and control systems.

This approach represents a transition from reactive repair to proactive adaptation, addressing the underlying vulnerability rather than repeatedly responding to flood damage after each event.

Attachment 3b DRS and special crossings resilience projects

Vulnerability assessment – DRS stations and special crossings vulnerable to hazard

	Hazard				Total
Asset Type	Inland flooding	Coastal inundation	Slips	Exposed to both	
Regulator stations	29	9	1	8	46 (24%)
Special crossings	2	3		5	10 (3%)

Project investment assessment – examples of DRS and special crossings projects

[redacted]

Estimated resilience expenditure on four priority projects

Attachment 4a Biomethane projects information

Typical biomethane project stages

Pre-feasibility – 8 to 16 weeks

Activities conducted include

Initial market analysis
- High-level network acceptance of biomethane flows
- Regional customer scoping

Basic technical assessment
- Site suitability and location
- Feedstock scan
- Basic technology review
- Initial infrastructure requirements

Preliminary financial evaluation
- CAPEX / OPEX estimate
- High-level project feasibility

Initial regulatory assessment
- Summary of key permits and consents
- Preliminary legal and compliance requirements

Decision Gate

- ✓ Initial technical feasibility
- ✓ Viable market
- ✓ First-pass financial outcomes are favourable
- ✓ Viable consenting / permitting pathway

Indicative opex cost
- $50k to $150k

Feasibility – 12 to 24 weeks

Activities conducted include

Detailed market analysis
- Scenario modelled network acceptance of biomethane flows
- Regional customer engagement

Detailed technical assessment
- Detailed site assessment and plant location scoping
- Detailed feedstock assessment
- Technical specifications compiled for vendor engagement and design
- Infrastructure and integration requirements

Comprehensive financial analysis
- Detailed CAPEX / OPEX estimates
- ROI and financial analysis

Preliminary commercial agreement
- Basic framework of contracts and commercial terms between parties

Decision Gate

- ✓ Technically feasible
- ✓ Viable offtake
- ✓ Financially viable
- ✓ Commercial model agreed

Indicative opex cost
- $200k to $500k

Front-End Engineering Design – 6 to 12 months

Activities conducted include

Full Commercial Due Diligence
- Feedstock supply, pricing, and key commercial risks

Binding Agreements
- Biomethane take off agreements ready to sign

Front End Engineering
- Sufficient engineering design to provide a firm price estimate for FID, including
  - Control philosophy
  - Civil/structural/geotechnical requirements
  - Datasheets for long lead procurement items ready for purchase
  - A 3D plant model
  - Safety and risk assessments
  - Material take offs including piping details, instrumentation, electrical cabling estimates etc
  - Hazard and Operability studies, design and constructability reviews

Decision Gate
- ✓ Technically feasible
- ✓ Off take agreement
- ✓ Financially viable

Indicative opex cost
- $0.5m to $1m

Final Investment Decision

Procurement

Construction

[redacted]

[redacted]

Attachment 4b Excerpts from Blunomy study – biomethane benefits assessment November 2025

Market scan of biomethane benefits assessment methodologies

Powerco

24 November 2025

Executive summary

Globally, networks value renewable gas as a strategic lever for mitigating asset risk and enabling lower-cost decarbonisation

KEY INSIGHTS

The market scan delivered five key insights that are relevant for Powerco's activities:

- While **no common methodology exists for quantifying renewable gas benefits for gas assets, networks align around three complementary narratives** to build stakeholder support for biomethane:
  - **Stranded asset mitigation**: Retaining customer base amidst the energy transition and reducing stranded asset risk
  - **System-wide decarbonisation at lower cost**: Positioning biomethane as a lower-cost alternative to electrification for network customers and the economy as a whole
  - **Socioeconomic value creation**: Leveraging co-benefits (employment, regional economic development) to secure political and regulatory buy-in
- **Across jurisdictions, the same drivers have prompted networks to support development in the biomethane value chain** :
  - Energy security concerns from declining gas supplies (e.g., Nordstream cut-off and EU-wide phase out of Russian gas imports)
  - Climate policy and decarbonisation targets (e.g., Net Zero by 2050, Denmark fossil gas phase-out by 2050)
  - Support for rural economic development (e.g., providing additional income streams for farmers)
- **Regulatory appetite for including biomethane CapEx in the RAB correlates strongly with national energy security priorities**. Countries facing supply vulnerabilities or import dependence grant broader regulatory asset treatment, enabling gas networks to socialise more biomethane investment costs.
- **Networks in mature biomethane markets have developed system planning tools to optimise the economics of biomethane integration at scale**. These tools factor in feedstock availability and changes in gas demand among other considerations to inform network rationalisation and biomethane connection planning (e.g., Evida and GRDF network mapping)
- **International experience reveals that biomethane assessments align with network ownership structures**. Where networks are state-owned, biomethane initiatives emerge through coordinated national energy planning, with system-level modeling identifying renewable gas as the most beneficial decarbonisation solution (e.g., Denmark's integrated energy strategy). In jurisdictions with privately-owned networks (e.g., Australia, UK), biomethane value assessment is market-driven, with individual network operators taking the lead in quantifying benefits, engaging regulators, and building commercial cases for renewable gas.

Note: In this report, the terms "biomethane" and "renewable gas" are used interchangeably.

[redacted]

Learnings from international experiences – Key drivers of bioCH_4

Governments value bioCH_4 adoption in response to declining fossil gas supplies, decarbonisation obligations, and rural economy needs

Fossil gas supply decline

- EU countries are facing declining fossil gas reserves, and ongoing geopolitical tensions are accelerating the shift away from traditional gas sources, placing gas assets at high risk if supply volumes prove insufficient.
- Biomethane is insulated from natural gas price volatility, offering a means to secure gas supply while reducing vulnerability to global supply shocks.

Decarbonisation mandates

- With national net-zero targets, gas networks face increasing pressure from regulators and industry customers to provide low-carbon energy solutions, or else risk obsolescence.
- Countries seek sustainable waste management solutions, particularly for organic waste.
- Biomethane offers a pathway to reduce emissions from gas assets, valorise organic waste, and provide customers in hard-to-abate sectors with a cost-effective means to decarbonise.

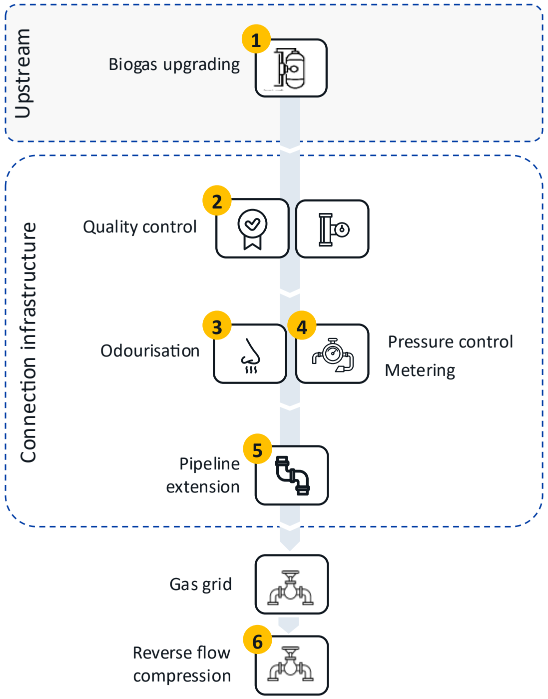
Rural economic development

- Rural areas face growing pressure on economic viability, improving on-farm waste management, and maintaining jobs.
- The biomethane value chain provides additional income streams for farmers while valorising their farm waste and providing local job opportunities (strong political drivers of biomethane support).

Learning from international experiences – Inclusion in RAB

Regulators facing energy security concerns are more likely to allow the inclusion of $bioCH_4$–related CAPEX in the RAB

France (GRDF) and Ireland (GNI) have the highest natural gas import dependence among the surveyed markets



Equipment type	GRDF	GNI	Evida	SGN	JGN
NG import %	100%	79%	56%	66%	0%
1 Biogas upgrading	✗	✗	✗	✗ Part of unregulated activities	✗ Part of unregulated activities
2 Quality and pressure control	✓	✓	✓	✓	✗
3 Odourisation	✓	✓	✓	✓	✗
4 Metering	✓	✓	✓	✓	✗
5 Pipeline extension	✓ 40% of costs included in RAB	✓ 70% of costs included in RAB	✓ Costs recovered by producer tariffs*	✗ 100% charged to $bioCH_4$ producer	✗
6 Reverse flow compression	✓	Pending approval from regulator	✓	No information available	No information available

GRDF provides advisory and knowledge-sharing services to $bioCH_4$ producers under its regulated business

Ireland has implemented progressive CAPEX regulations to accelerate $bioCH_4$ development

JGN's pipeline extension for the Malabar project was accepted into the RAB after the reg reset

Legend ✓ Included in RAB ✗ Not included in RAB

blunomy

Notes: *Evida charges $bioCH_4$ producers an additional tariff on grid injection to cover connections fees

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Case studies: GRDF – Gaz Reseau Distribution France; GNI – Gas Networks Ireland; Evida – Gas distribution company, Denmark; SGN – Scotia Gas Networks, United Kingdom; JGN – Jemena Gas Networks, Australia

Learnings from international experiences – Key benefits of $bioCH_4$

Gas networks use similar narratives for justifying $bioCH_4$ investments, despite quantifying benefits of $bioCH_4$ differently (1/2)

Benefit	GRDF	Evida	GNI	JGN	SGN
Customer retention and mitigating stranded asset risk	Provides industrial customers with a convenient decarbonisation lever	Retains large industrial customers with carbon tax liabilities and sustainability targets, and improve the economic viability of at-risk network assets	Retains large industrial customers in hard-to-abate sectors*, mitigating asset stranding risk as fossil gas use declines	Retains customers with legal GHG abatement needs. Injecting $bioCH_4$ will mitigate over NZD 1bn of stranded asset risk	$BioCH_4$ usage will extend commercial lifespan of gas network assets in islanded gas networks, reducing depreciation impact
System-wide decarbonisation at lower cost	Helps meet legal decarbonisation mandates and avoids 218 $kgCO_2e/MWh_{injected}$ compared to natural gas. $BioCH_4$ production costs will be up to 50% lower than natural gas in 2050†	Lowest-cost system decarbonisation option for the gas sector and hard-to-abate industries. Network modelling includes an internal carbon price to evaluate decarbonisation benefits	Local $bioCH_4$ production shields against gas market price volatility while supporting the decarbonisation of hard-to-abate sectors	$BioCH_4$ uptake avoids additional expenditure on fossil gas infrastructure, and is the most cost-effective use of bioenergy feedstock (in terms of decarbonisation impact) compared to biogas CHP	$BioCH_4$ is the lowest cost solution to decarbonise islanded grid systems, and provides the least disruption to industrial customers on the main gas grid

Legend Benefit recognised by network Benefit quantified in regulatory submissions

Notes: *Combined heat and power. †When including carbon tax.

Learnings from international experiences – Key benefits of $bioCH_4$

Gas networks use similar narratives for justifying $bioCH_4$ investments, despite quantifying benefits of $bioCH_4$ differently (2/2)

Benefit	GRDF	Evida	GNI	JGN	SGN
Social benefits (jobs, GDP, etc.)	✓ 🏛 EUR 14bn of economic benefit from the bioCH4 value chain in a 30% green gas scenario	✓ 🏛 $BioCH_4$ supports rural economic development and job creation	✓ 🏛 Meeting $bioCH_4$ targets would generate over 6,000 jobs across rural Ireland	✓ 🏛 Lowered decarbonisation subsidy requirement for hard-to-abate sectors	✓ Enables vulnerable customers in remote rural communities to switch to low-carbon, locally produced energy sources

Legend ✓ Benefit recognised by network 🏛 Benefit quantified in regulatory submissions

blunomy Notes: *Combined heat and power

[redacted]

Valuing biomethane projects

Biomethane projects create value through four streams, which can be assessed using two different approaches

Based on the findings from the market scan, there are four value streams created by biomethane projects on gas networks against the backdrop of declining gas demand

Avoided costs for Powerco's electricity network

Avoided stranded asset risk	Deferred decommissioning costs	Avoided loss of electricity network tariff from hard-to-abate customers (i.e., lost due to lack of green gas options)	Electricity network CapEx deferment benefit from gradual electrification ramp-up

Another value stream is the presence of new connection to the gas grid resulting from Coal & Oil customers transitioning, but this could also be part of BAU[1]

The value streams of a given project can be assessed through two approaches

System-level approach

Where the project's value reflects its contribution to system-wide avoided costs (using a proxy measure such as the project's relative contribution to the required level of biomethane injection)

Localised/sub-segment approach

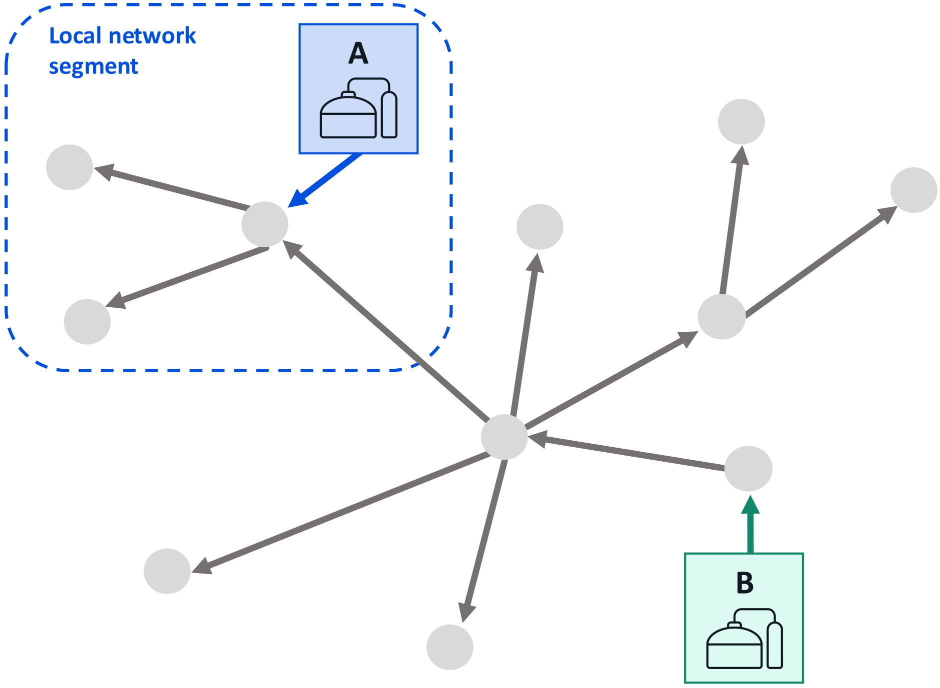
Where the value of a project is determined by the impact of injecting biomethane gas into its local network (e.g., Feilding gas network)

Notes: [1] As switching to natural gas is already a form of decarbonisation for these actors, the argument for green gas is m ore difficult here.

[redacted]

Valuing biomethane projects

Illustration: bioCH_4 benefits can be assessed at a system level or at the local level



Under a **system-level approach**, both project **A** and **B** are valued based on the biomethane they introduce into the system

Under a **local segment-level approach**, project **B**’s value is derived from hard-to-abate customers in the whole network while project **A**’s value is derived only from the branch it is injecting into

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