Gas Industry Company

Gas Supply and Demand Study

8 December 2023

Building a better working world

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The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 8 December 2023 ("**Report**"). The Report should be read in its entirety including the [cover letter/transmittal letter], the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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1. Executive summary

EY has been commissioned by the Gas Industry Company Limited (GIC) to investigate the current and future supply and demand in the gas industry in New Zealand. This report details the methodology and findings of this supply and demand study. The analysis has been completed in consultation with the GIC and a number of key stakeholders from within industry. These key stakeholders include field operators, large industrial consumers, gas network owners, retailers, and owners of gas-fired electricity generation.

This Report has considered four distinct scenarios. These scenarios have been developed in collaboration with the GIC and deliberately chosen as GIC wanted to explore unique pathways for the sector. Each scenario has certain benefits and disbenefits depending on which lens it is being viewed through. A high-level overview of the scenarios considered is provided in Table 1.

This Report has also considered a range of scenario enablers across policy and infrastructure, and how they may impact, or be impacted by, each of the scenarios. While these enablers were not explicitly modelled within the analysis, they help to set the context which underpins the assumptions in the scenarios and analysis, as well as help to identify the levers available to achieve certain outcomes.

1.1 Key findings

The key findings from this study can be summarised as follows:

1. **Demand is decreasing:** The closure of several large industrial users in recent years has materially reduced demand. However, the reasons for industrial closure are important to consider and distinguish. The Marsden Point oil refinery closed due to increased competition from global refineries which has pushed down margins. In contrast, the Waitara Valley methanol plant closure was due to natural gas supply constraints and Methanex has said it would restart the plant if supply were available. The decrease in demand is projected to continue across all scenarios as the economy decarbonises and consumers switch to low- or zero-emissions fuels. However, there is considerable uncertainty as to the rate at which this decrease will occur. Furthermore, not all consumers are equal. Development on the supply side is currently almost entirely dependent on long-term contracts for large amounts of fixed offtake. Users such as Methanex underwrite development on the supply side which has benefits to other smaller consumers. If demand from these large users is the first to disappear, remaining users may not be able to underwrite the necessary supply development.

2. **The current commercial environment is creating challenges for bringing new natural gas supply to market and demand may not be met:** There has been a dramatic reduction in upstream exploration activity in recent years. Drilling activity since 2015 has averaged 9.5 wells per year compared to 34 wells per year during the period 2002 to 2014[1]. Between those same periods, 2D seismic data acquisition (a means of identifying drilling targets) has reduced by 66%[1]. The number of permits with granted status has been decreasing since 2014 at a CAGR of -9.7%[1]. According to field operators, the reduced activity is due more to factors such as uncertainty around regulatory changes (in particular, decommissioning security arrangements), difficulty obtaining resource consents and difficulty financing for fossil fuel operations, rather than the scarcity of natural gas as a resource.

[1] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fpetroleum-reserves.xlsx

In all the scenarios considered, the best estimate of commercially viable future natural gas production (known as 2P reserves) is estimated to be insufficient to meet demand at some stage between 2025 and 2027. Even if production from 2C resources, which are not currently commercially viable, comes online the results still show natural gas production from all sources as being insufficient to meet demand at some stage between 2028 and 2034.

These factors, combined with a declining demand forecast, create a challenging environment for any investment in new natural gas supply which will likely require support from both Government and industry to overcome.

3. **Renewable supply options are on the horizon but require time to develop:** New Zealand has significant potential for biogas and biomethane production. Studies commissioned for the Gas Transition Plan Issues Paper[2] estimated that 7 PJ/year (roughly the energy consumed by residential consumers annually) of biogas is commercially viable at today's prices and 24 PJ/year is potentially available. The timing at which this biogas comes to market is difficult to estimate as it will require biogas production schemes to be built and/or infrastructure to be built to inject biomethane into the gas network. It may be accelerated by the introduction of renewable certification schemes to allow for a price premium to be supported and regulatory/policy support. For the purposes of exporting goods, such a certification scheme needs to be internationally recognized as international customers are unlikely to familiarise themselves with New Zealand specific standards.

   The benefits of a vibrant biogas sector in New Zealand would be significant from an environmental, economic, and strategic perspective. Biogas can provide options for hard to abate sectors where electrification is challenging, reduce the requirement for imported fuels, and divert organic waste from landfill. Who the end-user of biogas will be is currently unclear. Current estimates of the amount of commercially viable biogas fit nicely with residential consumption. However, depending on the price premium for green manufacturing (for example of green methanol), it may be advantageous (from both an economic and environmental viewpoint) for the biogas to be consumed by industrial consumers.

   In addition to biogas, there is potential for green hydrogen production in New Zealand, although much work is required to get there.

4. **There are potential opportunities to reduce emissions which could be actioned now**: The potential for CCUS to reduce emissions provides an opportunity for New Zealand to accelerate its emissions reduction, take advantage of its remaining natural gas reserves without compromising the emissions budget, and maintain a competitive advantage for trade exposed, emissions intensive industries. The simplest opportunity sits within the upstream emissions. From Figure 5 (bottom left chart) there is a maximum of between 6.2 and 9.3 million tonnes of CO_2 emissions that could be avoided between now and 2035 if CCUS were implemented to remove upstream emissions. The settings within the ETS allow suppliers to gain credit for sequestering their own emissions as it reduces their reported production emissions. However, once the gas is injected into the network, there is no ability to gain credit for sequestration of emissions from downstream use of gas through the ETS. Furthermore, the Resource Management Act lacks clarity as to whether sequestration is permitted under existing production permits and potential successor Acts are uncertain at this point. New tax incentives under the Inflation Reduction Act are creating tailwinds for the deployment of CCUS technologies globally. New Zealand should position itself to take advantage of new developments that come about as a result.

[2] https://www.mbie.govt.nz/dmsdocument/27255-gas-transition-plan-issues-paper-pdf
https://www.mbie.govt.nz/dmsdocument/27267-gas-transition-plan-biogas-research-report-february-2023-pdf

1.2 Scenarios overview

The modelling considered four scenarios to test a range of outcomes for supply and demand in the gas sector. No single scenario is considered a 'base case' but each represents the outcomes of key decision points in the sector. Hence, in contrast with other modelling, they are not a prediction of likely pathways but rather allow us to compare the interrelated impacts of the different decision points. This approach has been adopted as it provides for a richer range of conversations than where each scenario is treated as a variation to a base case. Inevitably, more scenarios could have been chosen, but for expediency the following were selected by GIC as representative of the wide range of outcomes.

The scenarios chosen were:

- ***Industry focus:*** tests a future where the industrial sector (in particular petrochemicals) remains the dominant consumer of gas.
- ***Methanex exits early:*** tests a future where the largest consumer exits, causing a major change to the supply demand balance.
- ***Elevate electricity:*** tests a future where the electricity sector is more heavily reliant on gas for its own security of supply for longer.
- ***Supply headwinds:*** tests a future where current supply is challenged and future supply is not able to be developed.

In particular, we note that the *Methanex exits early* scenario has a complete exit of all methanol production in 2029. This is in line with the Climate Change Commission's (CCC) Demonstration Path in its draft advice in 2021[3]. Subsequently, the CCC final advice amended this to allowing for a single methanol production train from 2029 as it was based on modelled gas supply at the time[4]. This original scenario has been included in our modelling to explore the impacts of a complete exit. It is not a forecast of Methanex's operations.

An overview of the scenarios is given in Table 1.

[3] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/evidence/advice-report-DRAFT-1ST-FEB/Evidence-CH-07-Where-we-are-currently-heading-26-Jan-2021-compressed-1.pdf

[4] https://www.climatecommission.govt.nz/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

Table 1: Scenario narratives

	Industry focus	Methanex exits early	Elevate electricity	Supply headwinds
Overview	▸ Sustained high demand from industrial users helps to underwrite new sources of natural gas in the near-to-medium term. ▸ Decarbonisation efforts out to 2035 are focused on getting off coal and decarbonising transport and electricity generation, after which the focus moves to reducing emissions from gas.	▸ Methanex signals that it will close its operations and exit New Zealand in 2029, causing supply-side development to stall. ▸ Industrial, commercial, and residential gas demand remains relatively high. ▸ There is higher demand from gas-fired electricity generators, with gas playing an important role out to 2050.	▸ Centred around an electricity system that relies on gas-fired generation to firm the intermittency of wind/solar and to provide dry year reserve. ▸ Gas is prioritised for electricity and industrial demand declines. ▸ Methanex continues to operate but reduces demand out to 2040 because of tightening supply.	▸ Considers a supply side which experiences a considerable reduction in existing and future supply. ▸ Demand from industrial, commercial, and residential sectors is sharply reduced due to lack of supply. ▸ Alternative sources of gas are developed in response to declining availability of natural gas supply.
Purpose	▸ To test a future where the industrial sector (in particular petrochemicals) remains the dominant consumer of gas.	▸ To test a future where the largest consumer exits, causing a major change to the supply demand balance.	▸ To test a future where the electricity sector is more heavily reliant on gas for its own security of supply for longer.	▸ To test a future where current supply is challenged and future supply is not able to be developed.
Demand assumptions	▸ Methanex operates at full capacity out to 2040. Waitara Valley closes in 2040 and Motunui-1 closes in 2045. ▸ Gas-fired electricity generation is rapidly phased out (baseload by 2030, cogeneration by 2035 and peaking and dry year reserve by 2040) to support industrial supply. ▸ Demand across the industrial, commercial, and residential sectors continues, with limited decline over the next decade.	▸ Methanex does not reopen Waitara Valley. Both plants at Motunui close in 2029 when its existing contract expires. ▸ Gas-fired generation is gradually phased out of the electricity mix. Baseload is phased out by 2033, cogeneration by 2048, and peaking and dry year reserve by 2050. ▸ Industrial, commercial, and residential sector demand continues, with limited decline over the next decade.	▸ Methanex does not reopen Waitara Valley. Motunui-1 closes in 2035 and Motunui-2 in 2040. ▸ Gas-fired generation is kept in the electricity mix. Baseload is phased out by 2037, and cogeneration by 2048. However, gas for peaking and dry year reserve remains in the mix beyond 2050. ▸ Moderate decline in demand for the industrial, commercial, and residential sectors.	▸ Methanex does not reopen Waitara Valley. Motunui-1 closes in 2035 and Motunui-2 in 2040. ▸ Gas-fired generation is phased out of the electricity mix. Baseload is phased out by 2030, cogeneration by 2035, and peaking and dry year reserve by 2050. ▸ Significant decline in demand for the industrial, commercial, and residential sectors.
Supply assumptions	▸ Supply outlook based on 2P production profiles published in the MBIE reserves data. ▸ 50% of the reported 2C resources are assumed to be converted to deliverable production. ▸ 30% of feasible biogas potential production is supplied to pipeline. ▸ Additional supply needed to meet demand comes from prospective resources and/or importing of LNG (assumed to be an option from 2030).	▸ Supply outlook based on reported 2P production profiles published by MBIE but reduced to 70% of reported production by 2029 to reflect supplier uncertainty over demand. ▸ 20% conversion of reported 2C resources to deliverable production. ▸ 30% of feasible biogas potential production is supplied to pipeline.	▸ Supply outlook based on 2P production profiles published in the MBIE reserves data. ▸ 40% conversion of reported 2C resources to deliverable production. ▸ 30% of feasible biogas potential production is supplied to pipeline. ▸ Additional supply needed to meet demand comes from prospective resources and/or importing of LNG (from 2030).	▸ Supply outlook based on reduced 2P production profiles published in the MBIE reserves data (reduced to 70% of reported production by 2027). ▸ 30% conversion of reported 2C resources to deliverable production. ▸ 50% biogas production is supplied to pipeline. ▸ Green hydrogen is used to supplement pipeline gas (20% blend by volume). ▸ Additional supply needed to meet demand comes from prospective resources and/or importing of LNG (from 2029).

1.3 Modelled gas demand

For each scenario there are five key drivers of demand considered. These are outlined in Table 2.

Table 2: Demand drivers

Demand Drivers	Description
Petrochemical industry	Driven by demand from Methanex and Ballance. This industry serves as a crucial source of firm demand and underpins almost half of current natural gas demand. Demand in this sector has major impacts on the supply demand balance. There is uncertainty around the timing of changes within this driver.
Gas-fired electricity generation	Gas is used for both baseload and peaking generation. Gas may also provide support if hydro storage lakes run low (a so-called *dry year*). Gas is also used for industrial cogeneration
Industrial Sector	Gas is used primarily to provide heat for manufacturing and industrial processes
Commercial Sector	Gas is used for commercial space heating, including gas boilers, hot water, and cooking
Residential Sector	Gas is used for space heating, hot water, and cooking within homes

The results of the modelled demand for each scenario are shown in Figure 1, followed by a summary of the key findings in Table 3. In all four scenarios, a decline in total gas demand is observed. Broadly, there are two distinct forces driving this decline:

1. The drive to decarbonise the economy (which includes reducing fossil fuel use for electricity generation)

2. The closure of large industrial consumers, noting that such closures may be due to increased global competition or upstream supply constraints

The potential to increase gas demand within certain sectors is also seen, for example where gas can provide an alternative to existing coal use, or the re-opening of the Waitara Valley methanol plant.

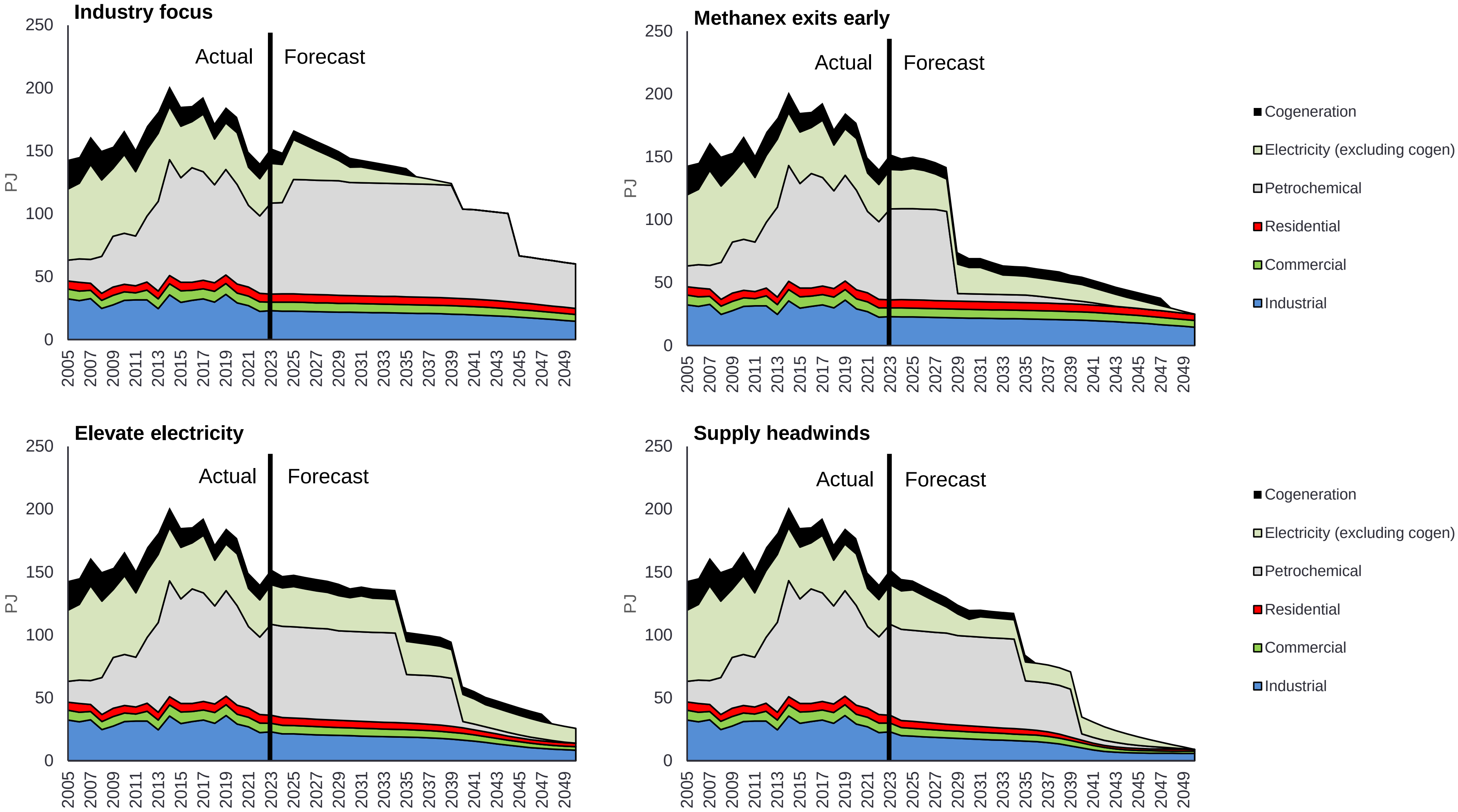

Figure 1: Total annual gas demand

Table 3: Summary of results from demand-side modelling for each scenario

Scenario	Modelled demand results summary
Industry focus	In the *Industry focus* scenario, there is higher demand in comparison to the other scenarios. This is driven by estimates for higher industrial demand, particularly from the petrochemical industries. Results show the demand for gas-fired generation (including cogeneration) rapidly phased out of the electricity mix, which is assumed to have zero dependence on gas by 2040. In the 2040s, the demand drops as Methanex stages the removal of gas from its three methanol trains.
Methanex exits early	In the *Methanex exits early* scenario, it is assumed there is a dramatic drop in demand in 2029 when Methanex closes its New Zealand methanol plants. Gas-fired generation (including cogeneration) take longer to phase out of the electricity mix, which now achieves zero dependence on gas by 2050. The only consumers left to underwrite supply side development are the electricity generators and the industrial consumers.
Elevate electricity	In the *Elevate electricity* scenario, there is higher gas demand for electricity generation than in any other scenario. In this scenario, gas-fired generation plays the critical role of firming intermittent renewable generation such as wind and solar. It also plays a role in providing dry year security. Industrial, commercial, and residential demand drops away slightly faster than in the *Industry focus* and *Methanex exits early* scenarios. This is assumed to be due to lower electricity costs and therefore higher electrification. However, in this scenario Methanex stages an exit in the mid- to late-2030s which leaves electricity generation to finance all necessary supply side development from the mid-2030s.
Supply headwinds	In the *Supply headwinds* scenario, the industrial, commercial, and residential demand is assumed to decline faster than in any other scenario. Methanex stages an exit in the mid- to late-2030s. Gas-fired generation is phased out of the electricity mix by 2050, with cogeneration phased out earlier in 2037.

1.4 Modelled gas supply

For each scenario there are five sources of supply considered. These are outlined in Table 4.

Table 4: Supply drivers

Supply source	Description
Natural gas	The primary source of current gas supply is through the development and production of domestic natural gas reserves and transported to end users through the transmission and distribution pipelines. MBIE reserves data of known 2P reserves and 2C resources[5] is the basis of the assumptions for each scenario's overall supply outlook. An unconstrained natural gas supply forecast is provided in Figure 2.
Biomethane/Biogas	Currently, biomethane production in New Zealand is used on-site for generating heat or electricity. Biogas can be upgraded and used to supplement natural gas without any changes required to pipelines or appliances. The analysis only considered production that was feasible to connect to the gas grid and not supply used for heat and power locally.
Green hydrogen	Green hydrogen can be blended with gas up to 20% by volume and used in existing networks and appliances. The low density of hydrogen means this 20% by volume is equal to 6% of the gas supply on an energy basis. The analysis considers hydrogen blending at the distribution network level to augment gas supply to residential and commercial consumers in Auckland and Wellington. These consumers are considered to have the lowest technical barriers to the use of blended hydrogen. The analysis does not include local supply of hydrogen to consumers not connected to the gas grid.
Liquefied Natural Gas (LNG)	LNG imports can offer an alternative solution to supplement domestic gas supply, allowing for greater flexibility in satisfying demand during peak consumption periods. LNG is higher cost than the domestic natural gas supply. Moreover, investment in additional infrastructure, such as an import terminal and upgrades to the gas network, will be required to support the use of LNG. In the analysis, imported LNG is used in certain scenarios to underpin supply where domestic gas

[5] See Appendix C for further details on petroleum reserves and resources definitions.

Supply source	Description
	or biogas, hydrogen and natural gas is insufficient to meet demand. It has been used as a balancing factor and imported to match demand.
Prospective supply	Prospective supply refers to additional natural gas production that has not been reported with the estimates of 2P reserves and 2C resources. This could include fields that come online as a result of exploration. There are currently 11 active petroleum exploration permits that could yield production and potential for further permits to be issued[6]. However, supply from these fields is potentially costly and development timeframes lengthy. Prospective supply has therefore been modelled alongside LNG import in terms of timeframes and cost as both these supply sources would have similar economic challenges.

Based on supply outlooks for existing domestic natural gas fields, and analysis of identified contingent resources, an unconstrained natural gas supply outlook was developed and is shown in Figure 2. This assumes production is not matched to demand but is produced according to currently likely timeframes for development and under the assumption that operators can sell all the natural gas into the market. The outlook based on MBIE production profiles for the current year shows a plateau between 2023 and 2026 and a decline in production from 2026 onwards until new resources can be brought into production. A plateau period appears possible out until the early 2030s as 2C resources are produced but decline is steep after this point. Due to the lead time in consenting and sanctioning new production it is unlikely that significant amounts of 2C resource can be accelerated to maintain or increase production. It should be noted that this scenario does not represent field operator plans, it is indicative only.

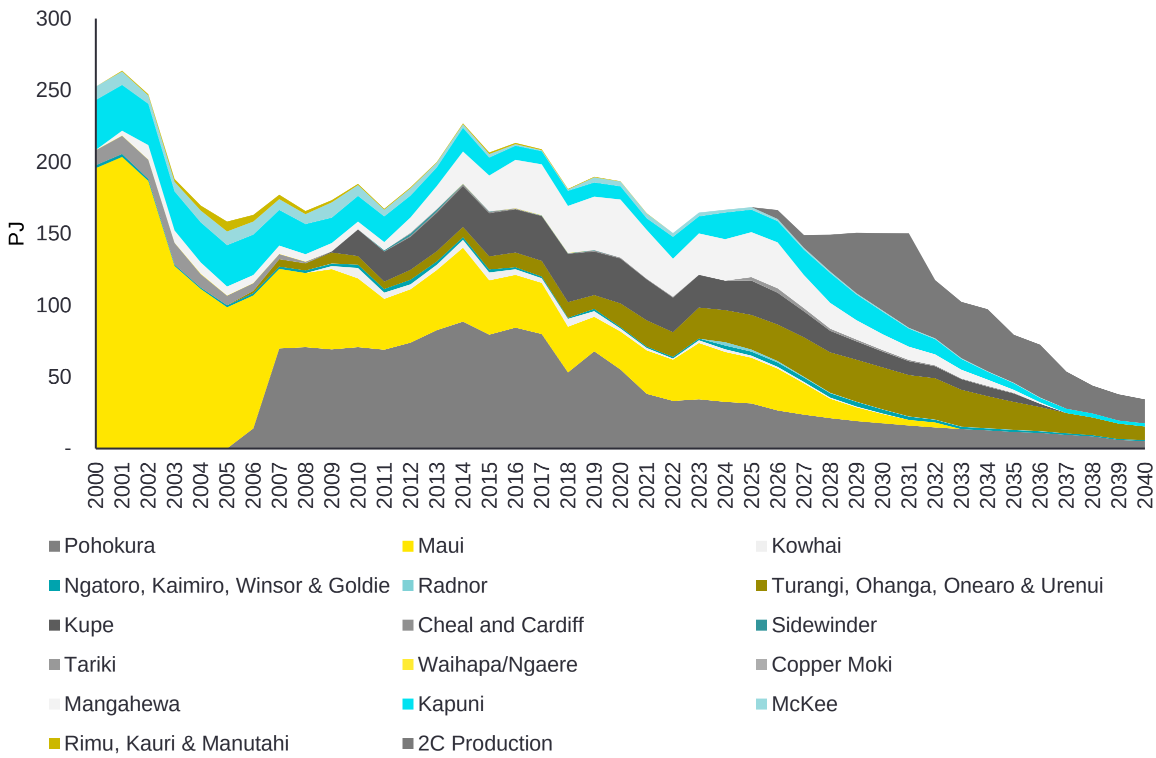

Figure 2: Unconstrained natural gas supply forecast

The results of the modelled supply for each scenario are shown in Figure 3, followed by a summary of the key findings in Table 5. The total annual demand for each scenario (as in Figure 1) is also shown in the charts.

[6] https://data.nzpam.govt.nz/permitwebmaps/?commodity=petroleum

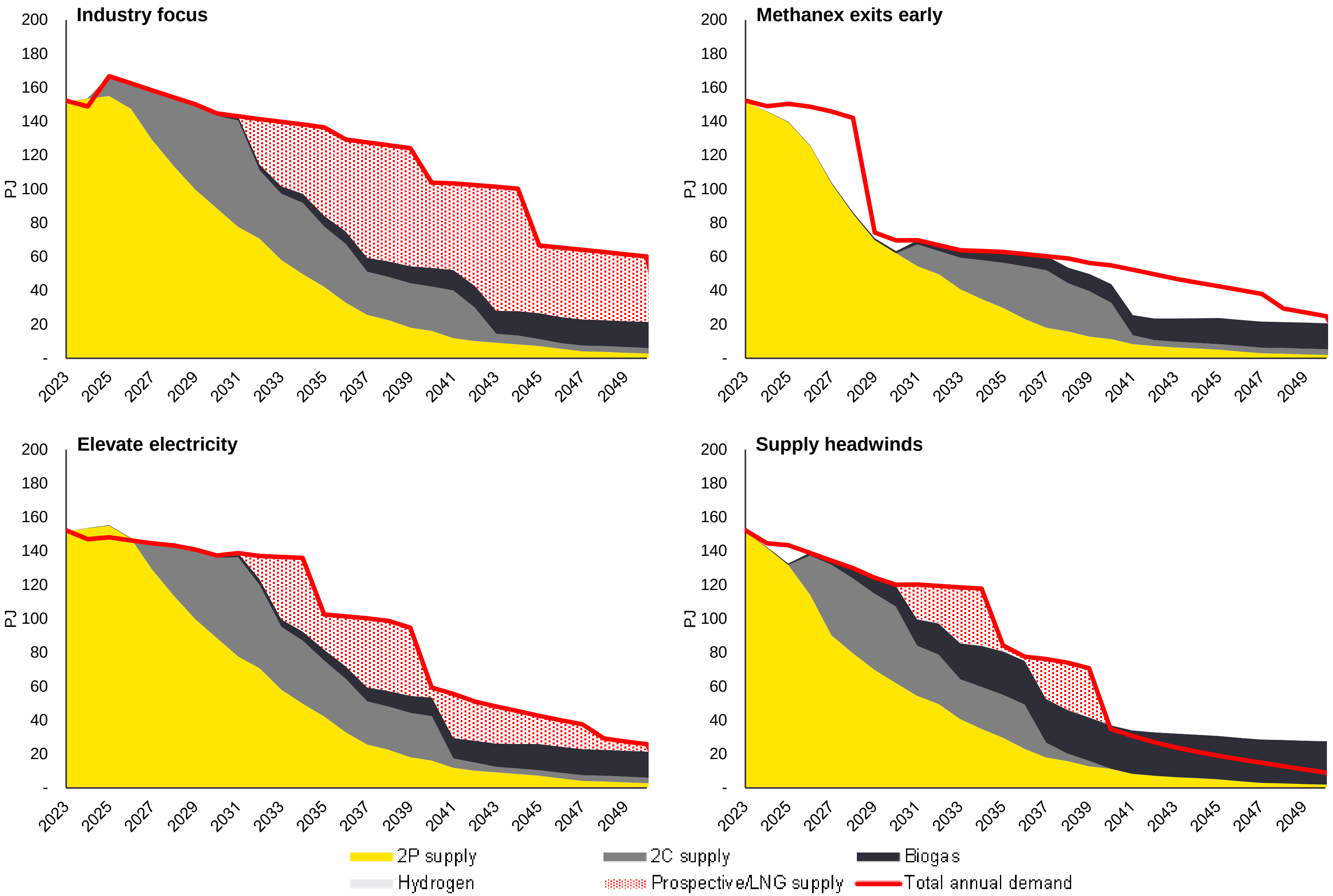

Figure 3: Modelled gas supply for each scenario. Note that the whitespace between demand and supply indicates a shortfall in supply.

Table 5: Summary of results of the modelled supply for each scenario

Scenario	Modelled supply results summary
Industry focus	In the *Industry focus* scenario, the results of the analysis show that: ▸ 2P production can support total annual demand up until 2025 based on current Methanex demand without Waitara Valley. ▸ Development of 2C resources will need to commence from 2025 and is able to support total annual demand up until 2031. ▸ Biogas supply ramps up after 2030 and grows to 6 PJ by 2035. ▸ Hydrogen supply is not directed to the gas network in this scenario. ▸ LNG/prospective supply is required from 2032 onwards.
Methanex exits early	In the *Methanex exits early* scenario, the results of the analysis show that: ▸ 2P production can support total annual demand up until 2025 based on current Methanex demand without Waitara Valley. ▸ Development of 2C resources is required but does not commence until 2030. ▸ Biogas supply ramps up after 2030 and grows to 6 PJ by 2035. ▸ Hydrogen supply is not directed to the gas network in this scenario. ▸ LNG/prospective supply is not available in this scenario.
Elevate electricity	In the *Elevate electricity* scenario, the results of the analysis show that: ▸ 2P production can support total annual demand up until 2027 based on current Methanex demand without Waitara Valley. ▸ Development of 2C resources will need to commence from 2028 and is able to support total annual demand up until 2031. ▸ Biogas supply ramps up after 2030 and grows to 6 PJ by 2035. ▸ Hydrogen supply is not directed to the gas network in this scenario. ▸ LNG/prospective supply is required from 2032 onwards.
Supply headwinds	In the *Supply headwinds* scenario, the results of the analysis show that: ▸ 2P production can support total annual demand up until 2024 based on current Methanex demand without Waitara Valley. ▸ Development of 2C resources will need to commence from 2025 and is able to support total annual demand up until 2026. ▸ Biogas supply ramps up early and grows to 25 PJ by 2035. ▸ Hydrogen supply, via blending in the distribution network, occurs and reaches 0.4 PJ by 2035.

1.5 Modelled outcomes

For each scenario three key outcomes are considered. These outcomes are: energy security, emissions reduction, and price outcomes, as described in Table 6.

Table 6: Modelled outcomes description

Outcomes	What is being testing with these outcomes:	What is learnt from these outcomes:
Energy security	▸ Is supply sufficient to meet total demand? ▸ If supply is scarce, some demand may be able to switch to an alternative fuel source. Is supply able to meet the non-switchable demand? ▸ The analysis distinguishes between production from 2P reserves and other forms of production such as 2C conversion, biogas, and hydrogen to account for uncertainty in production between these sources.	▸ How does energy security differ between the scenarios? ▸ What are the key levers that can be pulled to provide greater security of supply?

Outcomes	What is being testing with these outcomes:	What is learnt from these outcomes:
Emissions reduction	▸ Forecast of emissions from the natural gas sector broken down among upstream, midstream, and downstream components. ▸ Comparison with the Climate Change Commission's modelling of their demonstration path scenario used to determine the emissions budget. ▸ Opportunities for carbon capture and utilisation or storage	▸ How do the scenarios compare with the those that informed the emissions budget? ▸ What are the key levers that can be pulled to reduce emissions? ▸ Are there opportunities to accelerate emissions reductions?
Price outcomes	▸ Wholesale price outcomes are considered in each scenario for differing levels of natural gas (2P and 2C), biogas, LNG and hydrogen. ▸ Commodity costs are estimated through a breakdown of fixed vs variable components, biogas feedstock costs, LNG import costs, and hydrogen levelized-cost estimates ▸ Total price is broken down among wholesale price (commodity and carbon), network costs, retailer, metering, and regulatory components	▸ How does affordability differ between the different scenarios? ▸ What is driving the changes in price? ▸ What are key levers that can be pulled to ensure greater energy affordability?

The modelled outcomes for each of these areas are described in the following sections for each scenario.

1.5.1 Energy security outcomes

Security of supply is a critical measure of energy sector performance. To quantify security of supply a graduated score has been created. Rather than a binary supply sufficiency measure, supply adequacy has been assessed within a certain tolerance. It is considered reasonable to include this tolerance because in certain applications fuel switching can occur which mitigates insufficient supply. For example, dry year reserve and baseload gas-fired electricity generation could be substituted with coal-fired generation if the gas supply were insufficient. In this way, the demand has been split into '*switchable*' demand and '*non-switchable*' demand to better understand the security of supply measure.

Furthermore, the security forecast to be provided by 2P supply is considered as a separate score from security forecast to be provided by all indigenous gas supply (which includes conversion of 2C, biogas, and hydrogen). The reason for breaking down security in this way is because the 2C, biogas, and hydrogen supply all have higher uncertainty than the 2P supply. In this way, the score provides further insights and allows understanding of the key driver of security in any given year of a scenario.

The security of supply score is 0 if supply is below non-switchable demand, 1 if supply is greater than or equal to non-switchable demand but less than total demand, and 2 if supply is greater than or equal to total demand. This scoring system is applied separately to 2P supply (on its own) and 2P+ supply (2P+ supply is the sum of 2P, 2C, biogas, and hydrogen supply). Adding the 2P and 2P+ scores together results in a score that varies from 0 (when security is very low and there is a high chance of demand curtailment) to 4 (when security is very high and there is little chance of demand curtailment).

This approach does not consider LNG imports or prospective supply within the security of supply score because the model uses the deficit between supply and demand to calculate the volumes required for either LNG import or prospective supply. It is emphasised that there is a significant risk associated with relying on prospective supply and/or LNG import. The former is highly uncertain, and the latter is both expensive and poses a strategic risk around imported fuels.

Figure 4 shows the security of supply score in each scenario along with the supply and demand (including non-switchable and switchable demand) charts. The chart is discussed in detail and commentary is provided in Table 7.

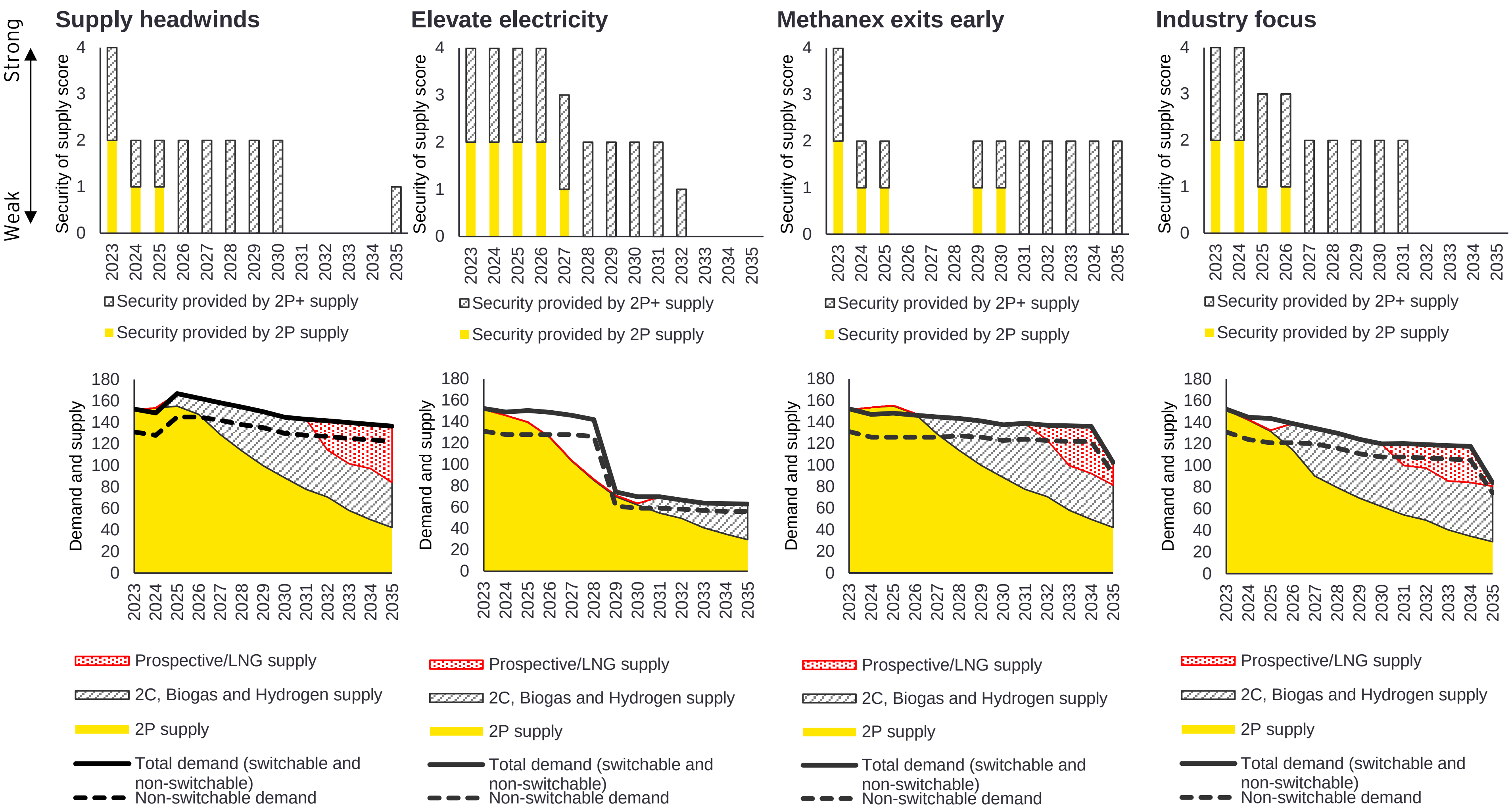

Figure 4: Security of supply score (top row) and the supply demand balance (bottom row) across the scenarios. Note that the whitespace between demand and supply indicates a shortfall in supply.

Table 7: Summary of modelled energy security outcomes for each scenario

Scenario	Modelled energy security outcomes summary
Industry focus	In the *Industry focus* scenario shown in the first column of Figure 4, the security of supply score is 4 through to 2024 then drops to 3 in 2025. This drop in 2025 is due to the assumed reopening of the Waitara Valley methanol plant (a significant increase in demand) which causes the 2P supply to drop below the total demand but stay above the non-switchable demand. The score stays at 3 through to 2026. During this time, 2P supply is able to meet the non-switchable demand and 2P+ supply is able to meet total demand. In 2027, the score drops to 2. This is because 2P supply drops below the non-switchable demand in 2027. In 2032, the score drops to zero as 2P+ supply is not able to meet the non-switchable demand.
Methanex exits early	In the *Methanex exits early* scenario, the assumed closure of Methanex is signalled in advance and therefore there is less 2P supply and all conversion of 2C resources is deferred. For this reason, as shown in the second column of Figure 4, security of supply score drops to 2 in 2024 and stays there in 2025. At this score, 2P supply (and also 2P+ supply) is able to meet non-switchable demand but insufficient to meet total demand. In 2026 the score drops to zero, indicating that 2P+ supply is not able to meet even the non-switchable demand. This occurs earlier than the assumed lead time on LNG imports within the model, so this presents a scenario wherein significant demand curtailment would be required. In 2029, when Methanex exits, the score increases to 2. In 2029 and 2030, 2P supply can meet non-switchable demand but insufficient to meet total demand. It is assumed that, beyond 2030 with demand somewhat stabilised (albeit at a much lower level), 2P+ is boosted by the conversion of 2C resources. In 2031, the 2P supply drops below the non-switchable demand but the 2P+ supply (with boosted 2C conversion) can meet total demand, therefore the score stays at 2. Because of the crucial role that Methanex plays in underwriting supply side development, the security of supply in the *Methanex exits early* scenario is particularly uncertain. If Methanex were to close its operations in New Zealand, it may be necessary for smaller consumers to band together on large, fixed offtake contracts to provide greater certainty for the suppliers. Moreover, the scale of the market could fall below the materiality threshold for field operators and new supply would not be brought to market.
Elevate electricity	In the *Elevate electricity* scenario shown in the third column of Figure 4, the security of supply score stays at 4 through to 2026 then drops to 3 in 2027. The high security in the early years of this scenario is driven by the assumed low demand in the industrial, commercial, and residential sectors in this scenario. The drop in 2027 is due to the 2P supply dropping below the total demand but staying above the non-switchable demand. This drops again to 2 in 2028 as 2P supply drops below the non-switchable demand. From 2023 right through till 2031, the 2P+ supply is able to meet total demand. This situation changes in 2032 when 2P+ supply drops below total demand but stays above non-switchable demand, meaning the score drops to 1. The situation changes again in 2033 when 2P+ supply drops below the non-switchable demand and the score drops to zero.
Supply headwinds	In the *Supply headwinds* scenario shown in the fourth column of Figure 4 the security of supply drops to 2 in 2024. In 2024 and 2025, both 2P and 2P+ supply drop below total demand but stay above the non-switchable demand. In 2026, 2P supply drops below non-switchable demand, but 2P+ supply picks up and can meet total demand through till 2030. The score therefore stays at 2. In 2031, the score drops to zero as 2P+ is no longer able to meet even the non-switchable demand. The score increases to 1 in 2035 as one of the Motunui methanol trains is assumed to close.

1.5.2 Emissions reduction outcomes

New Zealand is united toward achieving net zero emissions by 2050, and dramatic reductions are required from all sectors to achieve this objective.

The emissions in each scenario are categorised and quantified as either, upstream emissions, midstream emissions, or downstream emissions. Downstream emissions are further broken down according to the demand drivers.

Figure 5 shows the emissions for each scenario broken down among these categories. It is emphasised that the modelling only accounts for emissions from gas. It does not include emissions from additional consumption of coal, diesel, or otherwise, that may be required in the event of gas supply being unavailable. If high emissions fuels were substituted for gas due to supply constraints, this would lead to higher emissions which is not shown in the figures. Furthermore, the emissions accounting in this analysis only covers New Zealand emissions. This is particularly relevant to the emissions reduction that is seen from Methanex closures. The emissions intensity of methanol produced in New Zealand is estimated to be around 0.74 tonnes of CO_2 per tonne of methanol[7]. In contrast, producing methanol from coal (a potential outcome if the Motunui and Waitara Valley plants close) creates around 1.25 tonnes of CO_2 per tonne of methanol. This raises material doubt around any level of global emissions reduction associated with closing Methanex's New Zealand operations. Modelled emissions outcomes in each scenario is discussed in Table 8.

The uptake of CCUS has been presented as a sensitivity to the *Industry focus* scenario in Figure 5. The most apparent application of CCUS is within the upstream emissions. Recent estimates by Wood Beca suggest reductions of approximately 460 kt of CO_2 in 2035 from upstream emissions alone[8]. Outside of upstream applications, the viability of CCUS is linked to high on-site gas demand, high CO_2 concentration in the flue gas, and access to nearby sequestration. These factors point to certain Taranaki-based industries being well placed to take up CCUS. CCUS is gaining momentum internationally due to tax incentives in the Inflation Reduction Act[9]. New Zealand has seen recent activity in CO_2 reinjection at geothermal power plants[10]. If CCUS is to be used as a tool for emissions intensive trade exposed (EITE) entities, this would require appropriate incentives. In Figure 5, where CCUS is shown, it is assumed that 236 kt of CO_2 from upstream emissions (approximately 50% of the total) and 629 kt of CO_2 from petrochemical emissions (approximately 35% of the total) are sequestered. The assumption for petrochemical emissions means the Motunui and Waitara Valley methanol plants have a net emissions factor of around 0.5 tonnes of CO_2 per tonne of methanol[11], which is comparable though still materially higher than the Geismar 3 project[12] which is estimated to be less than 0.4.

Table 8: Summary of modelled emissions reduction outcomes for each scenario

Scenario	Modelled emissions reductions outcome summary
Industry focus	In the *Industry focus* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 2.8 million tonnes of CO_2 additional emissions as compared to the CCC demonstration path. This is approximately 3.8% higher emissions. From Figure 5 (bottom left chart), results show the higher emissions in this scenario come from Methanex, which is running at maximum production. The higher emissions in this scenario likely only occur in New Zealand, with no actual change in global emissions.
Methanex exits early	In the *Methanex exits early* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 11 million tonnes of CO_2 fewer emissions as compared to the CCC demonstration path. This is approximately 15% lower emissions. From Figure 5 (bottom left chart), results show the lower emissions in this scenario is due to Methanex closing early. As discussed above, Methanex's emissions should be considered in the context of global emissions rather than domestic emissions. It is considered unlikely that closing Methanex's New Zealand plants would reduce global emissions.
Elevate electricity	In the *Elevate electricity* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 3.1 million tonnes of CO_2 additional emissions as compared to the CCC demonstration path. This is approximately 4.2% higher emissions. From Figure 5 (bottom left chart), results show the higher emissions in this scenario come from higher use of gas in the electricity generation mix.
Supply headwinds	In the *Supply headwinds* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 11.5 million tonnes of CO_2 fewer emissions as compared to the CCC demonstration path. This is approximately 15.3% lower emissions. From Figure 5 (bottom left chart), results show the lower emissions in this scenario come from lower industrial demand and lower use of gas in the electricity generation mix.

[7] Emission intensity estimated based on private communications with GIC

[8] https://www.mbie.govt.nz/dmsdocument/27264-review-of-ccus-ccs-potential-in-new-zealand-march-2023-pdf

[9] https://www.iea.org/policies?topic=Carbon%20Capture%20Utilisation%20and%20Storage&region%5B0%5D=North%20America

[10] https://www.energynews.co.nz/news/geothermal/125507/geothermal-generators-team-carbon-reinjection

[11] Calculated from GHG emissions data and Methanex plant capacity.

[12] https://www.methanex.com/geismar-3/

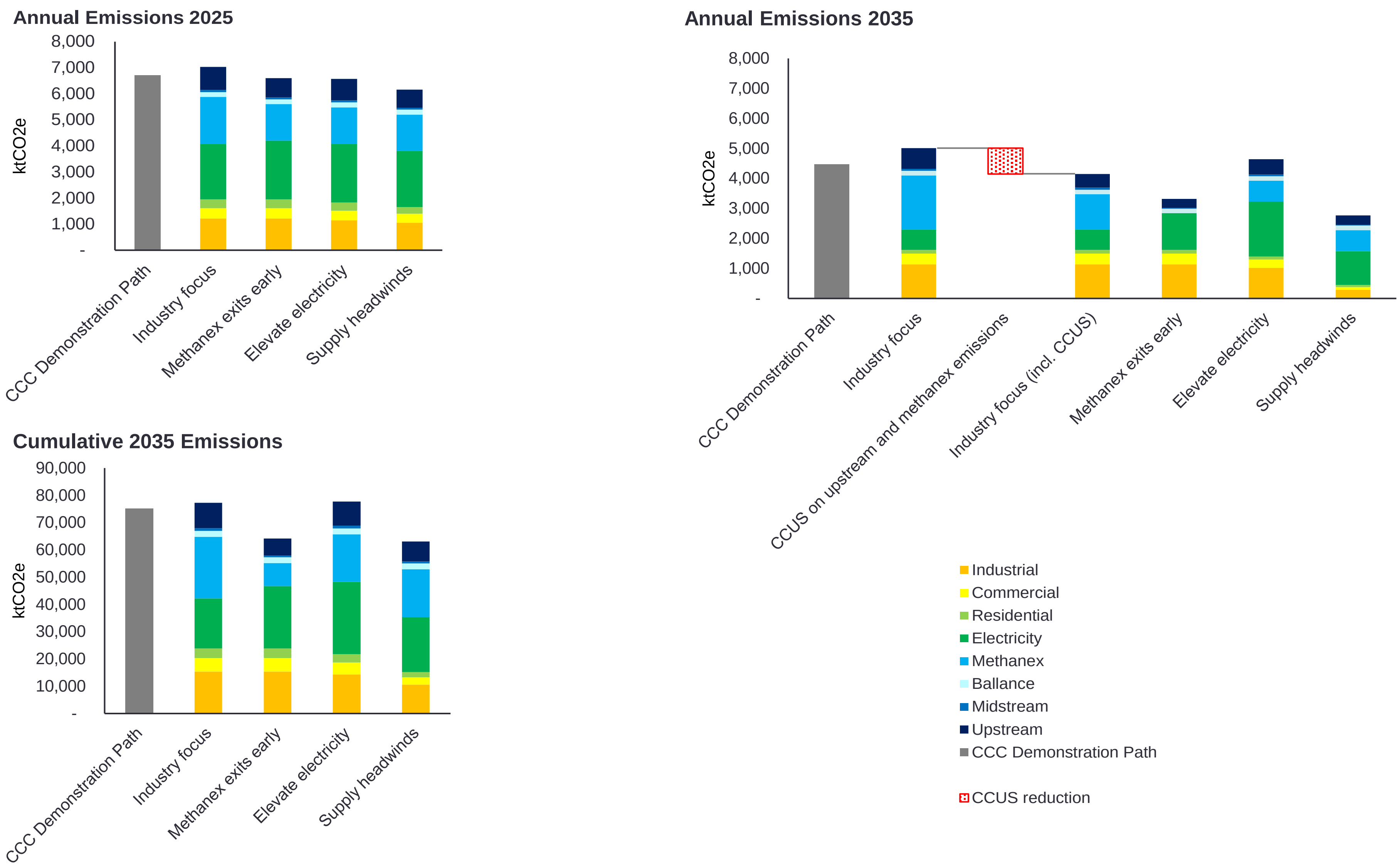

Figure 5: Summary of modelled emissions outcomes

1.5.3 Price outcomes

The components that make up the final cost of gas to residential consumers include wholesale gas price, retail, metering, regulator levies, transmission, distribution, and carbon costs.

In all scenarios, results show the estimated cost of gas increasing. This is due to a forecast increase in natural gas per-unit production costs as volumes decline; increasing penetrations of biogas, hydrogen, and LNG, all of which are presently more expensive than indigenous natural gas; conversion of 2C resources to production; and increasing carbon price. The cost of gas for residential consumers is shown in Figure 6 for small residential consumers (with annual demand of 15 GJ) large residential consumers (with an annual demand of 40 GJ).

The different supply sources (natural gas, biogas, hydrogen, and LNG/prospective) have slightly different estimated costs across the four different scenarios. This is because they have different levels of production in each scenario which affects their price. This is shown in the top row of Figure 7. The modelling does not consider willingness to pay and the potential for different users to bear different cost levels. This could mean that some users are willing to use higher cost biogas (for example) earlier than other users. Moreover, switching may be driven by other factors such as corporate decarbonisation objectives, that decrease price sensitivity. Modelled price outcomes in each scenario are discussed in Table 9.

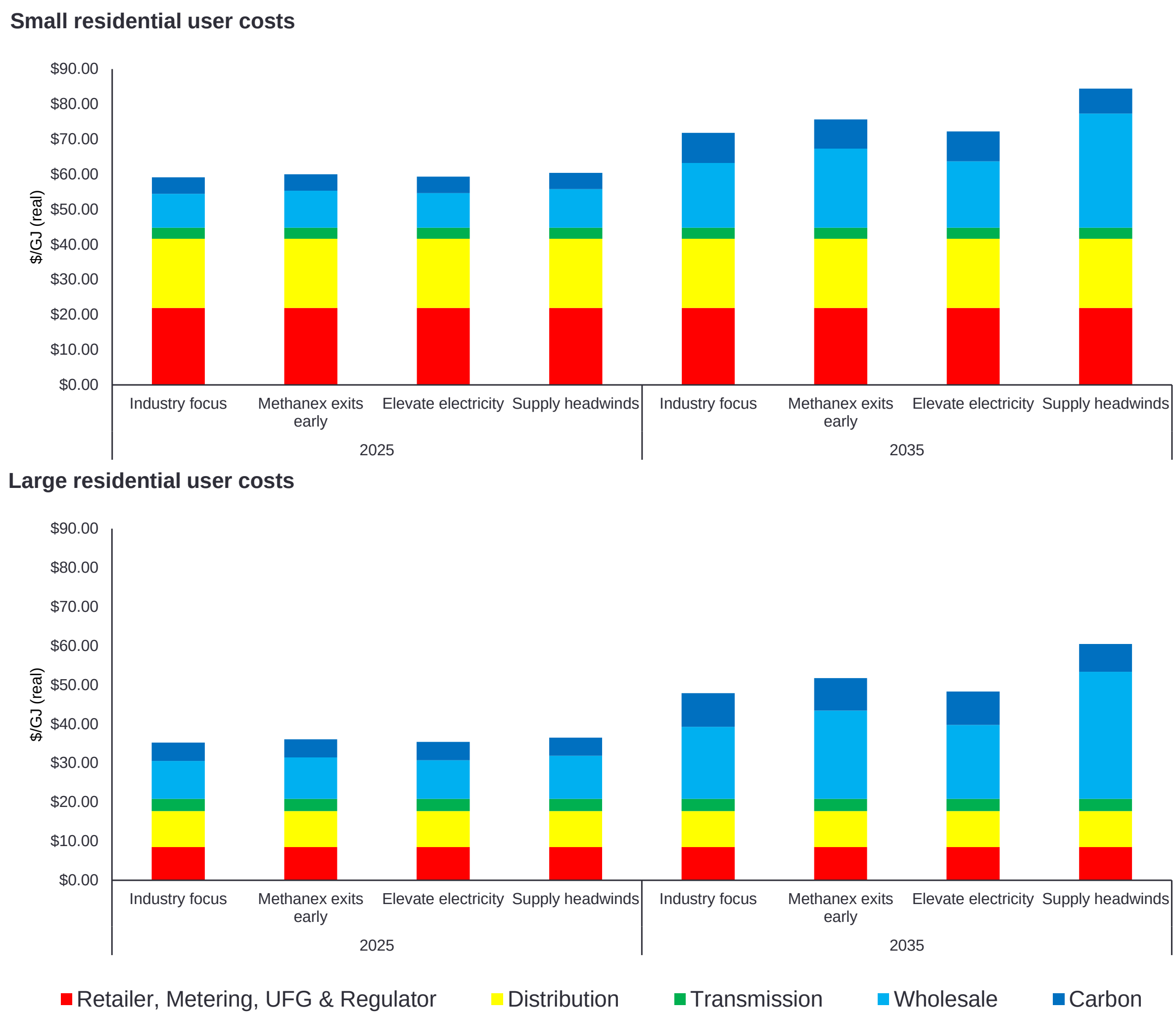

Figure 6: Residential gas user costs across the scenarios in 2025 and 2035

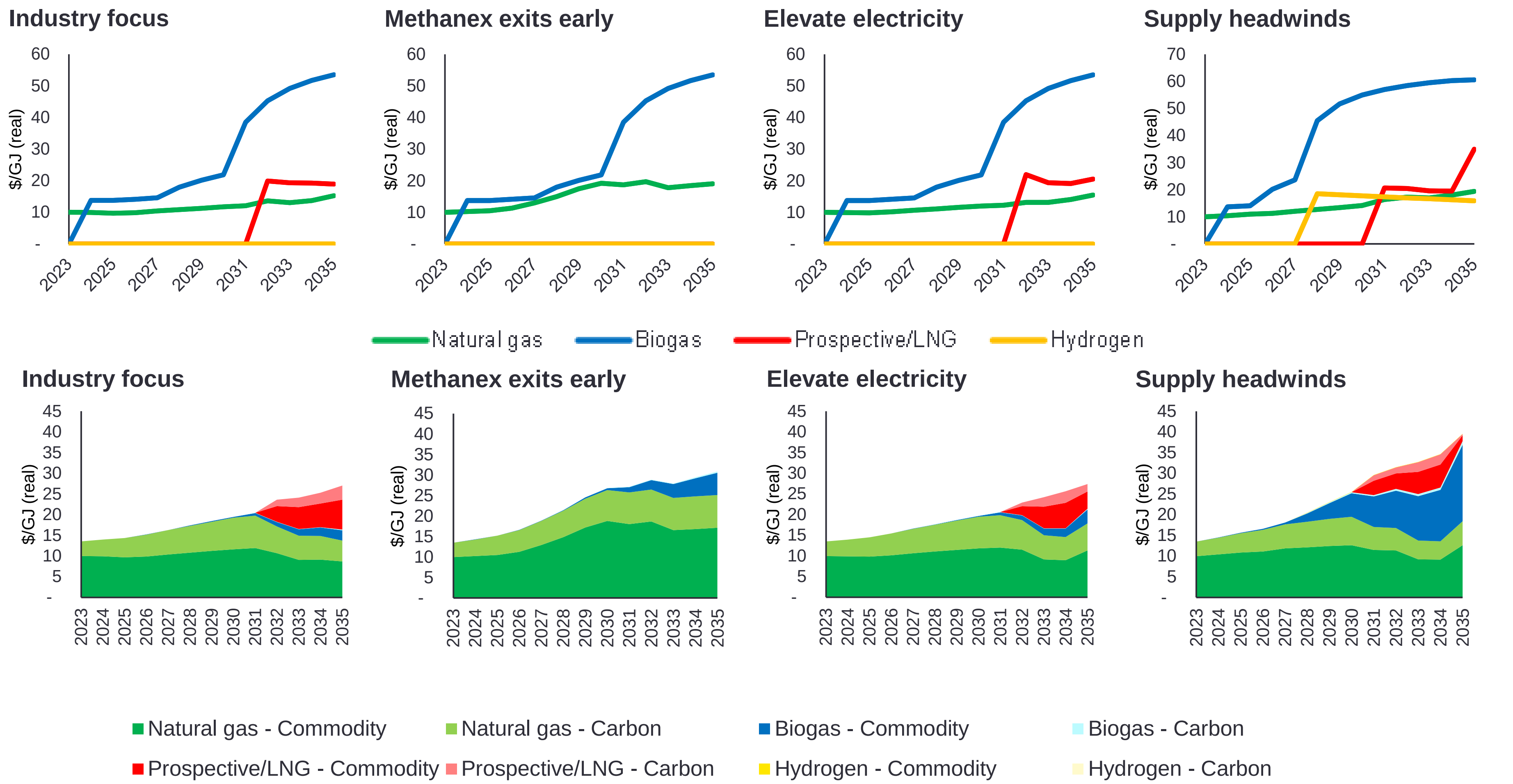

Figure 7: Fuel costs across the different fuels (top row) and Energy-weighted average price (EWAP) (bottom row) in each scenario

Table 9: Summary of modelled price outcomes for each scenario

Scenario	Modelled price outcomes summary
Industry focus	In the *Industry focus* scenario, results show the cost of gas for small residential users are estimated to increase by approximately 21.5% between now and 2035. The estimated wholesale cost of gas (including carbon costs) increases by 88.5% over this period, mainly due to higher carbon prices and a material LNG/prospective supply component.
Methanex exits early	In the *Methanex exits early* scenario, results show the cost of gas for small residential users are estimated to increase by approximately 26.1% between now and 2035. This is driven by an estimated 102.7% increase in the wholesale cost of gas (including carbon costs), which comes from higher carbon prices, a significant increase.in the cost of natural gas, and a material biogas component.
Elevate electricity	In the *Elevate electricity* scenario, results show the cost of gas for small residential users are estimated to increase by approximately 21.7% between now and 2035. This is driven by an estimated 88.7% increase in the wholesale cost of gas (including carbon costs), which comes from higher carbon prices and a material LNG/prospective supply component.
Supply headwinds	In the *Supply headwinds* scenario, results show the cost of gas for small residential users are estimated to increase by approximately 39.7% between now and 2035. This is driven by an estimated 153.3% increase in the wholesale cost of gas (including carbon costs), which comes from higher carbon prices and material components of both biogas and LNG/prospective supply.

2. Introduction

2.1 Background

The GIC regularly publishes supply and demand studies, which investigate the current and forecast production and consumption of natural gas in New Zealand. These studies aim to provide the gas sector with insights into the medium to long-term outlook, thereby supporting businesses in making informed decisions for their future operations.

GIC is also involved in the development of the Gas Transition Plan to understand how the gas industry will transition to a low carbon future and meet the obligations under New Zealand's Emissions Budget. In 2023, GIC is seeking to update the study by incorporating the key shifts in the industry, including the displacement of thermal electricity generation by renewable electricity resources and rising level of investment in new technologies. These changes have potential to impact future investments in gas production and infrastructure.

2.2 Purpose of this report

The potential for a net zero carbon gas industry in New Zealand and its associated impacts to the supply chain and consumption portfolio remain highly uncertain. The legislated emission reduction targets require a transit away from natural gas. However, the transition needs to balance reliability and affordability with sustainability. To comprehend these uncertainties, GIC commissioned EY to develop and model a set of scenarios that are representative of a range of possible futures for the industry. This report provides outcomes of the scenarios and sensitivity analysed as part of our report noting that there may be other possible scenarios and sensitivities which are outside the scope of this report.

In undertaking this work, various aspects of the supply and demand uncertainties have been examined, including production volumes and demand, as well as the potential impacts on the economy and wider energy system. The intention was to provide a wide-ranging analysis of the potential outcomes associated with the scenarios and support investigations by policymakers and stakeholders in the sector.

During the scenario and model development phase of this work, several workshops with GIC teams were held to better understand the extent of which these uncertainties could impact the future and investment outlook of the gas industry. Additionally, a number of confidential interviews with key gas suppliers were held to align the modelling methodology with industry viewpoints concerning the availability and commercialization of natural gas supply in the future.

In addition, the key industry players were provided with an opportunity to respond to the draft report. The viewpoints of stakeholders, experts, and industry players provided us with additional insights, perspectives, and a deeper understanding of the nuances within the natural gas sector.

This report presents the findings of this work. Through the analysis, the aim is to provide clarity on the different possible futures of the gas industry in New Zealand and the potential associated supply and demand forecasts.

3. Gas scenarios

The gas sector is currently entering a period of significant transformation as part of the broader energy transition to meet global decarbonisation objectives. How this plays out in New Zealand is highly uncertain and influenced by a range of domestic and global factors, including policy and strategic decisions as well as the evolution of technology and markets. To understand the possible outcomes associated with varying these factors, this study uses scenarios based on different narratives and drivers which give rise to different outcomes. The scenarios have been developed based on both publicly available information and discussions with stakeholders across the sector. For this report, the framework shown in Figure 8 is used to perform and guide the analysis.

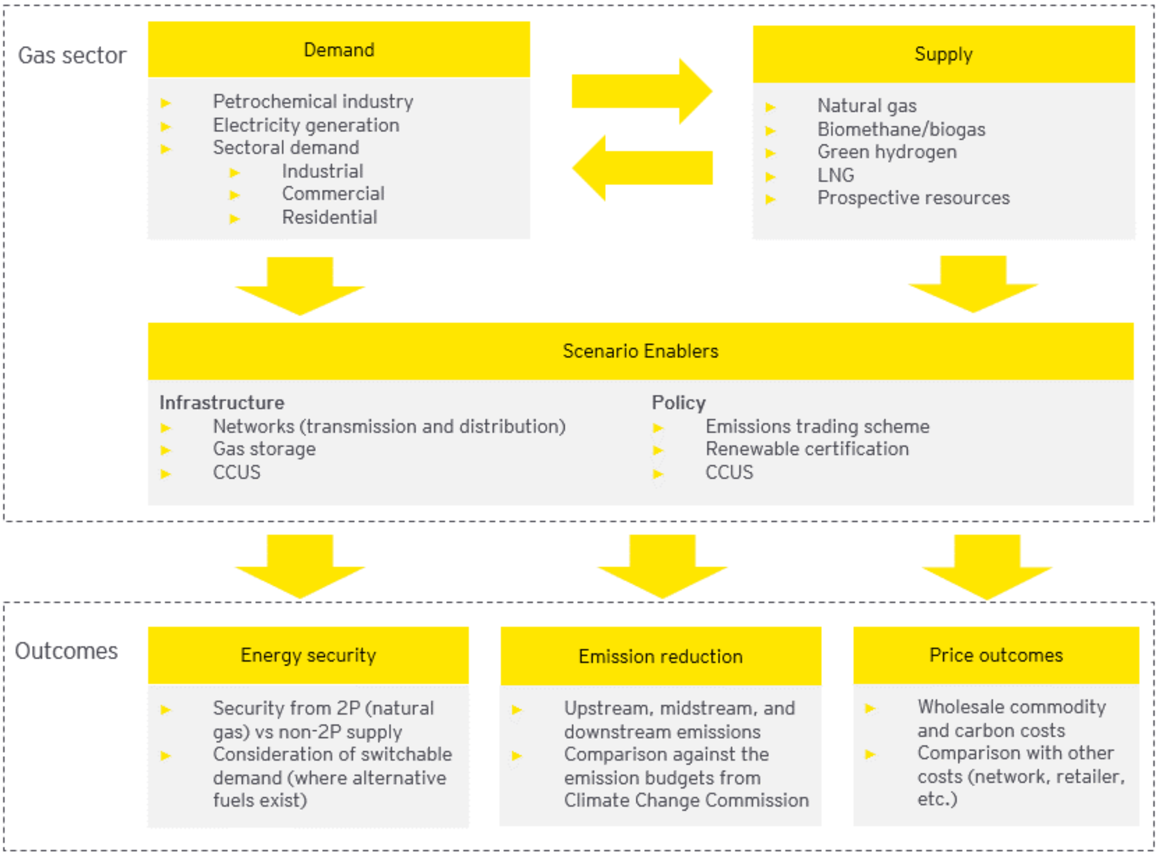

Figure 8: Gas scenario framework

3.1 Sector context

The gas sector operates within a complex and changing market and regulatory environment. Government and business decarbonisation goals are creating uncertainty as to the role of gas. This creates both challenges and opportunities for the gas sector in determining its fate. The outcome will determine the balance of gas supply and demand, and broader energy system security into the future.

In July 2023, the Ministry of Business, Innovation and Employment (MBIE) published the annual reserves update[13]. This showed that 2P gas reserves have dropped and that the conversion of 2C resources to 2P reserves is required[14]. The amount of 2P reserves is falling due to a lack of

[13] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/petroleum-reserves-data/

[14] This report adopts the definitions of reserves according to the Petroleum Resources Management System (revised June 2018) as included in appendix C.

investment which is needed to prove the amount of known reserves (and thereby increase it) and convert 2C resources into 2P reserves.

At the same time as reserves forecasts are decreasing, the demand context is uncertain. Large petrochemical gas users, including Methanex (which uses approximately 45% of New Zealand's domestic gas production) and Ballance, are looking at options to decarbonise their operations.[15] Similarly, the use of gas for industrial heat is likely to reduce into the future as businesses seek to reduce their emissions, primarily through electrification. On the other hand, the mothballing of Waitara Valley by Methanex is a reversible measure. If sufficient gas supply were available, Methanex could reactivate this plant. Hence, while gas demand has decreased, there may be pockets of unmet demand that could be reactivated should the right conditions emerge.

Gas has, and will continue to, play a key role in helping to balance New Zealand's electricity system. However, the role of gas-fired electricity generation in the market is changing. Currently, gas provides both baseload and peaking generation, as well as cogeneration[16]. It also plays a limited role as a strategic reserve during dry years. As baseload thermal generation is retired, it is expected to be replaced by more intermittent renewable generation, primarily wind and solar. Gas is expected to play an important role in this transition to renewables by providing dispatchable generation during periods of peak demand and during calm and cloudy periods where less or no solar or wind is available.

The changing role of gas creates significant uncertainty for the future demand and supply of gas. While the overall demand for gas is generally expected to decrease into the future, understanding and managing the rate of reduction in demand, and timings of significant changes (for example, an early exit of Methanex), are critical to maintaining energy security into the future. This is also required to support any future investment in gas infrastructure required to maintain energy security into the future as part of the energy transition.

Although the uncertainty around the changing role of gas presents challenges for new investment, it also creates some significant opportunities. While low temperature end-use of gas can be easily electrified, medium and high temperature end-use is more challenging and may require investment in innovation such as biogas, CCUS, and hydrogen. These innovations have the potential to help ensure energy security and support the energy transition more broadly.

With so many moving parts involved in the future supply and demand for gas, it is useful to consider scenarios. The following section describes the scenarios developed to help understand the different potential futures for gas supply and demand, and how this affects energy security.

3.2 Scenario narratives

The modelling considered four scenarios to test a range of possible outcomes for supply and demand in the gas sector. No single scenario is considered a 'base case' but each represents the outcomes of key decision points in the sector. Hence, in contrast with other modelling, they are not a prediction of likely pathways but rather allow us to compare the interrelated impacts of the different decision points. This approach has been chosen in order to provide for a richer range of conversations than where each scenario is treated as a variation to a base case. Inevitably, more scenarios could have been chosen, but for expediency the following were selected as representative of the wide range of outcomes.

The scenarios are as follows.

The ***Industry focus*** scenario involves a relatively high level of demand that comes mainly from large industrial consumers. Methanex reopens their Waitara valley plant in 2025 and demand from other

[15] Methanex, submission to MBIE Process Heat in New Zealand: Opportunities and Barriers to lowering emissions, 1 March 2019.
[16] Cogeneration is where generation is coupled with industrial heat demand, such as at the Whareroa plant which is used to produce both electricity and heat for Fonterra's dairy factory.

industrials remains relatively high with only a moderate decline before 2035. Demand from gas-fired electricity generators is low in this scenario with the electricity system achieving 100% renewable status by 2040. The presence of large industrial consumers means that supply side development in natural gas proceeds because it is underwritten by long-term contracts for fixed offtake. This is a scenario wherein decarbonisation efforts out till 2035 are focused on removing fossil fuels from the electricity supply, electrifying transport, and removing coal as a source of industrial process heat. Beyond 2035, the focus shifts toward decreasing gas consumption through fuel switching and the use of new technologies.

The purpose of the *Industry focus* scenario is to test a future where the industrial sector (in particular petrochemicals) is the dominant consumer of gas.

The ***Methanex exits early*** scenario assumes that Methanex closes its operations and exits New Zealand in 2029 (when a material supply contract ends[17]). The significant reduction in demand causes supply side development to stall. Industrial, commercial, and residential gas demand remains relatively high (the same as in the "*Industry focus*" scenario). There is higher demand from gas-fired electricity generators than in the "*Industry focus*" with the electricity system achieving 100% renewable status by 2050. The exit of Methanex means that supply side development in natural gas is highly restricted due to difficulties associated with financing. This manifests in reduced 2P production and lower conversion of 2C resources.

The purpose of the *Methanex exits early* scenario is to test a future where the largest consumer exits, causing a major change to the supply demand balance and a disruption to existing market dynamics where gas is brought to market supported by large, long-term contracts.

The ***Elevate electricity*** scenario involves a demand forecast that centres around an electricity system that relies on gas-fired generation to firm the intermittency of wind and solar and also to provide dry year reserve. The electricity system does not achieve 100% renewable status by 2050. Methanex does not reopen its Waitara valley plant but keeps Motunui-1 running until 2035 and Motunui-2 until 2040. Demand from other industrials declines reasonably quickly as electricity is cheap, promoting fuel switching. Without such a strong Methanex presence, and reduced industrial consumption, supply side development struggles but still proceeds in a limited way.

The purpose of the *Elevate electricity* scenario is to test a future where the electricity sector is more heavily reliant on gas for its own security of supply for longer.

The ***Supply headwinds*** scenario considers a supply side which experiences considerable difficulty in moving ahead with new development. Demand from industrial, commercial, and residential sectors is assumed to be sharply reduced. Methanex does not reopen its Waitara valley plant but keeps Motunui-1 running until 2035 and Motunui-2 until 2040. Demand from gas-fired electricity generators is phased out early for both baseload and cogeneration but peaking and dry year reserve still operates until 2050.

The purpose of the *Supply headwinds* scenario is to test a future where current supply is challenged and future supply is not able to be developed.

These scenarios have been deliberately chosen to explore unique pathways for the sector. Each scenario has certain benefits and disbenefits depending on which lens it is being viewed through. In particular, we note that the *Methanex exits early* has a complete exit of all methanol production in 2029. This is in line with the Climate Change Commission's (CCC) Demonstration Path in its draft advice in 2021[18]. Subsequently, the CCC final advice amended this to allowing for a single methanol production train from 2029 as which was based on modelled gas supply at the time[19].

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[17] https://www.scoop.co.nz/stories/BU1807/S00444/methanex-signs-nz-supply-agreements-for-gas-supply-to-2029.htm
[18] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/evidence/advice-report-DRAFT-1ST-FEB/Evidence-CH-07-Where-we-are-currently-heading-26-Jan-2021-compressed-1.pdf
[19] https://www.climatecommission.govt.nz/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

This original scenario has been included in our modelling to explore the impacts of a complete exit. It is not a forecast of Methanex's operations. Table 10 lists the key assumptions for the scenarios.

Table 10: The key differences in the demand and supply forecast between the scenarios

	Industry focus	Methanex exits early	Elevate electricity	Supply headwinds
Gas demand	▸ Methanex reopens Waitara Valley in 2025 and operates at the full production of 3 plants out to 2040. ▸ Ballance completes stage 1 of its decarbonisation programme by 2030 and begins stage 2 in the early 2040s. Its gas demand reaches zero by 2058. ▸ Gas-fired generation is rapidly phased out of the electricity mix. Baseload is phased out by 2030, cogeneration by 2035, and peaking and dry year reserve by 2040. ▸ The industrial (excluding petrochemical), commercial, and residential sectors see a small decline in demand. There is a 10% reduction in gas for high temperature process heat and a 15% reduction for residential space heating by 2035.	▸ Methanex does not reopen Waitara Valley. Both plants at Motunui close in 2029 when its existing contract expires. ▸ Ballance completes stage 1 of its decarbonisation programme by 2028 and begins stage 2 in 2036. Its gas demand reaches zero by 2044. ▸ Gas-fired generation is gradually phased out of the electricity mix. Baseload is phased out by 2033, cogeneration by 2048, and peaking and dry year reserve by 2050. ▸ The industrial (excluding petrochemical), commercial, and residential sectors see a small decline in demand. There is a 10% reduction in gas for high temperature process heat and a 15% reduction for residential space heating by 2035.	▸ Methanex does not reopen Waitara Valley. Motunui-1 closes in 2035 and Motunui-2 in 2040. ▸ Ballance completes stage 1 of its decarbonisation programme by 2029 and begins stage 2 in 2039. Its gas demand reaches zero by 2050. ▸ Gas-fired generation is kept in the electricity mix. Baseload is phased out by 2037, and cogeneration by 2048. However, gas for peaking and dry year reserve remains in the mix beyond 2050. ▸ The industrial (excluding petrochemical), commercial, and residential sectors see a moderate decline in demand. There is a 24% reduction in gas for high temperature process heat and a 33% reduction for residential space heating by 2035.	▸ Methanex does not reopen Waitara Valley. Motunui-1 closes in 2035 and Motunui-2 in 2040. ▸ Ballance completes stage 1 of its decarbonisation programme by 2029 and begins stage 2 in 2039. Its gas demand reaches zero by 2050. ▸ Gas-fired generation is phased out of the electricity mix. Baseload is phased out by 2030, cogeneration by 2035, and peaking and dry year reserve by 2050. ▸ The industrial (excluding petrochemical), commercial, and residential sectors see a large decline in demand. There is a 50% reduction in gas for high temperature process heat and a 50% reduction for residential space heating by 2035.

	Industry focus	Methanex exits early	Elevate electricity	Supply headwinds
Gas supply	▸ Supply outlook based on production profiles in MBIE's reported petroleum reserves data. ▸ 50% of the reported 2C resources are converted to deliverable production. ▸ Uptake of biogas depends on feedstock; lead times vary between 1-8 years. ▸ 30% of biogas production is supplied to pipeline. ▸ Green hydrogen is not used to supplement gas supply. ▸ Any further supply is supported by development of prospective resources and/or importing of LNG. Earliest start date for this is 2030.	▸ Supply outlook based on production profiles in MBIE's reported petroleum reserves data. An adjustment factor of 70% is gradually applied between now and 2029 to account for lower supply side development as a result of Methanex exiting. ▸ 20% of the reported 2C resources are converted to deliverable production. ▸ Uptake of biogas depends on feedstock; lead times vary between 1-8 years. ▸ 30% of biogas production is supplied to pipeline. ▸ Green hydrogen is not used to supplement gas supply.	▸ Supply outlook based on production profiles in MBIE's reported petroleum reserves data. ▸ 40% of the reported 2C resources are converted to deliverable production. ▸ Uptake of biogas depends on feedstock; lead times vary between 1-8 years. ▸ 30% of biogas production is supplied to pipeline. ▸ Green hydrogen is not used to supplement gas supply. ▸ Any further supply is supported by development of prospective resources and/or importing of LNG. Earliest start date for this is 2030.	▸ Supply outlook based on production profiles in MBIE's reported petroleum reserves data. An adjustment factor of 70% is gradually applied between now and 2026 to account for regulatory and financial hurdles. ▸ 30% of the reported 2C resources are converted to deliverable production. ▸ Uptake of biogas depends on feedstock; lead times vary between 1-5 years. Shorter lead times (roughly half the other scenarios) are a response to headwinds in natural gas. ▸ 50% of biogas production is supplied to pipeline. The higher percentage is in response to headwinds in natural gas. ▸ Green hydrogen is blended in pipeline gas (20% blend by volume or 6% blend by energy). ▸ Any further supply is supported by development of prospective resources and/or importing of LNG. Earliest start date for this is 2030.

3.3 Scenario drivers

While the scenario narratives provide an overview of the conditions and key assumptions for each scenario being considered, the scenario drivers describe the key levers which are pulled within the modelling to capture each scenario. These scenario drivers are broken down into demand and supply categories. The specific drivers under each of these areas are summarised in Table 11, Table 12, and Table 13 below, with the further details of each driver included in Appendix A.

Table 11: Demand drivers description

Demand Drivers	Description
Petrochemical industry	Driven by demand from Methanex and Ballance This industry serves as a crucial demand driver and underpins almost half of current gas demand It is a source of significant uncertainty as large consequences hinge on the decisions of individual players
Gas-fired electricity generation	In an ordinary year, gas is used for both baseload and peaking generation. Gas may also provide support if hydro storage lakes run low (a so-called *dry year*) Fast-start gas turbines can provide firming capacity for intermittent solar and wind generation Gas is also used for industrial cogeneration
Industrial Sector	Gas used primarily to provide heat for manufacturing and industrial processes
Commercial Sector	Gas use for commercial space heating, including gas boilers, hot water, and cooking
Residential Sector	Gas use for space heating, hot water, and cooking within homes

Table 12: Supply drivers description

Supply Drivers	Description
Natural gas	The primary source of current gas supply through the development and production of domestic gas reserves. Transportation of gas to end users through the transmission and distribution pipelines. MBIE reserves data of known 2P reserves and 2C resources is the basis of the assumptions for each scenario's overall supply outlook.
Biomethane/Biogas	Currently, biogas production in New Zealand is presently for on-site applications, particularly for generating heat or electricity. Biogas can be upgraded to biomethane and used to supplement natural gas with contingency upon the specific assumptions made within each scenario.
Green hydrogen	Green hydrogen can be blended with natural gas up to 20% by volume and used in existing networks and appliances. The low density of hydrogen means this 20% by volume is equal to 6% by energy.
Liquefied Natural Gas (LNG)	LNG imports can offer an alternative solution to supplement domestic gas supply, allowing for greater flexibility in satisfying demand during peak consumption periods. However, in cases where there is limited capacity to import LNG in substantial quantities, it becomes necessary to invest in additional infrastructure, such as an import terminal and upgrades to the gas network, to support the use of LNG.
Prospective supply	Prospective supply refers to additional natural gas production that has not been reported with the estimates of 2P reserves and 2C resources. These may include fields that come online as a result of exploration.

Furthermore, several key scenario enablers are identified which can be broadly categorised as either infrastructure or policy. While the modelling has not accounted for these scenario enablers directly, they remain crucial assumptions, without which the scenarios would not be coherent. All key enablers are core aspects of the gas industry. Section 6 gives a further description of the background of these enablers' and how they have helped shape the thinking in this work.

Table 13: Key scenario enablers

Scenario Enablers	Key Description
Gas pipeline	Gas pipelines infrastructure is required to serve remote demand with conventional natural gas Supply and demand assumptions will impact investment in transmission pipeline, distribution networks and connection points
Gas storage	Improve reliability and resiliency by providing a flexible supply of gas and greater adaptability during seasonal demand fluctuations Potential extra underground storage facilities are considered in this study
CCUS	Enables emissions reduction for both conventional gas supply, as well as end use CCUS is assumed to be economically viable in certain applications, particularly on the supply side but also in certain demand side applications
Carbon price	Key economic driver for the decarbonisation of the gas sector, and energy sector more broadly The carbon price forecast aligns with Climate Change Commission's demonstration path
Renewable gas certification	Recognise and reward low carbon gas production e.g., biogas production Varying the availability of renewable gas certification leads to distinct levels of adoption of low carbon gas supply in each scenario

3.4 Scenario outcomes approach

The outcomes, and how they vary between scenarios, are assessed through the different lenses of energy security, emissions reduction, and price outcomes. Table 14 below summarises what these outcomes are testing and what learnings are gained by considering them.

Table 14: Modelled outcomes description

Outcomes	What is being testing with these outcomes:	What is being learnt from these outcomes:
Energy security	▸ Is supply sufficient to meet total demand? ▸ If supply is scarce, some demand may be able to switch to an alternative fuel source. Is supply able to meet the non-switchable demand? ▸ Distinction between production from 2P reserves and other forms of production such as 2C conversion, biogas, and hydrogen to account for uncertainty in production.	▸ How does energy security differ between the scenarios? ▸ What are the key levers that can be pulled to provide greater security of supply?
Emission reduction	▸ Forecast of emissions from the gas sector broken down among upstream, midstream, and downstream components. ▸ Comparison with the Climate Change Commission's modelling of their demonstration path scenario used to determine the emissions budget. ▸ Opportunities for carbon capture and utilisation or storage	▸ How do the scenarios compare with the those that informed the emissions budget? ▸ What are the key levers that can be pulled to reduce emissions? ▸ Are there opportunities to accelerate emissions reductions?
Price outcomes	▸ Wholesale price outcomes are considered in each scenario for differing levels of natural gas (2P and 2C), biogas, LNG, and hydrogen. ▸ Commodity costs are estimated through a breakdown of fixed vs variable components, biogas feedstock costs, LNG import costs, and hydrogen LCOH estimates ▸ Total price is broken down among into wholesale price (commodity and carbon), network costs, and retailer, metering, and regulatory components	▸ How does affordability differ between the different scenarios? ▸ What is driving the changes in price? ▸ What are key levers that can be pulled to ensure greater energy affordability?

4. Modelled gas demand

In this section, the forecast of annual demand in each scenario is presented. Demand for natural gas comes from a small number of very large consumers – such as Methanex, Ballance, electricity generators, and large industrials (particularly Fonterra, Oji fibre solutions, and New Zealand Steel), and a very large number of small consumers, such as residential homes and businesses. Demand is broken down into components to provide a clear picture of what is driving changes in each scenario.

4.1 Total annual demand

Total annual demand for gas in 2022 was around 145 PJ[20]. This has declined from a peak of approximately 250 PJ in 2001[20]. Recently, the decline in gas demand has been driven by the closure of large industrial facilities such as the Waitara Valley methanol plant in 2021 and the Marsden point oil refinery in 2022.

Large fluctuations in gas demand are driven by hydro storage levels in the electricity sector impacting gas usage for power generation and by the operations (cyclical and otherwise) of industrial plants. In all four scenarios, a continuation of this decline in total gas demand is observed. Broadly, two distinct forces are driving this decline:

1. The drive to decarbonise the economy (which includes reducing fossil fuel use for electricity generation)

2. The assumed closure of large industrial consumers, noting that such closures may be due to increased global competition or upstream supply constraints

There is also the potential for gas demand to increase within certain sectors, for example where gas can provide an alternative to existing coal use, or the re-opening of the Waitara Valley methanol plant. The total annual demand for all four scenarios is shown in Figure 9.

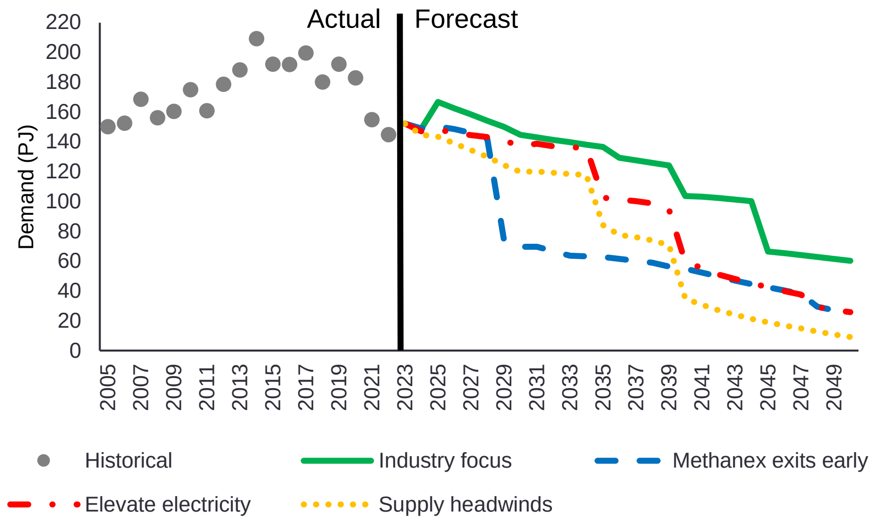

Figure 9: Total annual demand for the four scenarios

[20] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fgas.xlsx&wdOrigin=BROWSELINK

Figure 10 shows the annual demand split between the different components of industrial, commercial, residential, petrochemical, electricity, and cogeneration. Table 15, Table 16, Table 17, and Table 21 show the per scenario breakdown of demand across the different components for selected years.

In the *Industry focus* scenario, results show higher demand in comparison to the other scenarios. This is driven by higher industrial demand, particularly from the petrochemical industries. The demand for gas-fired generation (including cogeneration) is rapidly phased out of the electricity mix, which is assumed to have zero dependence on gas by 2040. In the 2040s, results show demand dropping as Methanex stages the removal of natural gas from its three methanol trains.

In the *Methanex exits early* scenario, results show a dramatic drop in demand in 2029 when Methanex closes its New Zealand methanol plants. Gas-fired generation (including cogeneration) take longer to phase out of the electricity, which is assumed to achieve zero dependence on gas by 2050. The only consumers left to underwrite supply side development are the electricity generators and the industrial consumers.

In the *Elevated electricity* scenario, results show higher gas demand for electricity generation than in any other scenario. In this scenario, gas-fired generation plays the critical role of firming intermittent renewable generation such as wind and solar. It also plays a role in providing dry year security. Industrial, commercial, and residential demand drops away slightly faster than in the *Industry focus* and *Methanex exits early* scenarios. This is assumed to be due to lower electricity costs and therefore higher electrification. However, in this scenario Methanex is assumed to exit in the mid- to late-2030s which leaves electricity generation to finance any and all necessary supply side development from the mid-2030s.

In the *Supply headwinds* scenario, results show industrial, commercial, and residential demand decline faster than in any other scenario. Methanex exits in the mid- to late-2030s. Gas-fired generation is phased out of the electricity mix by 2050, with cogeneration phased out earlier in 2037.

Sections 4.2, 4.3, and 4.4 further explore the petrochemical, gas-fired electricity generation, and sectoral demand drivers, respectively, within each scenario

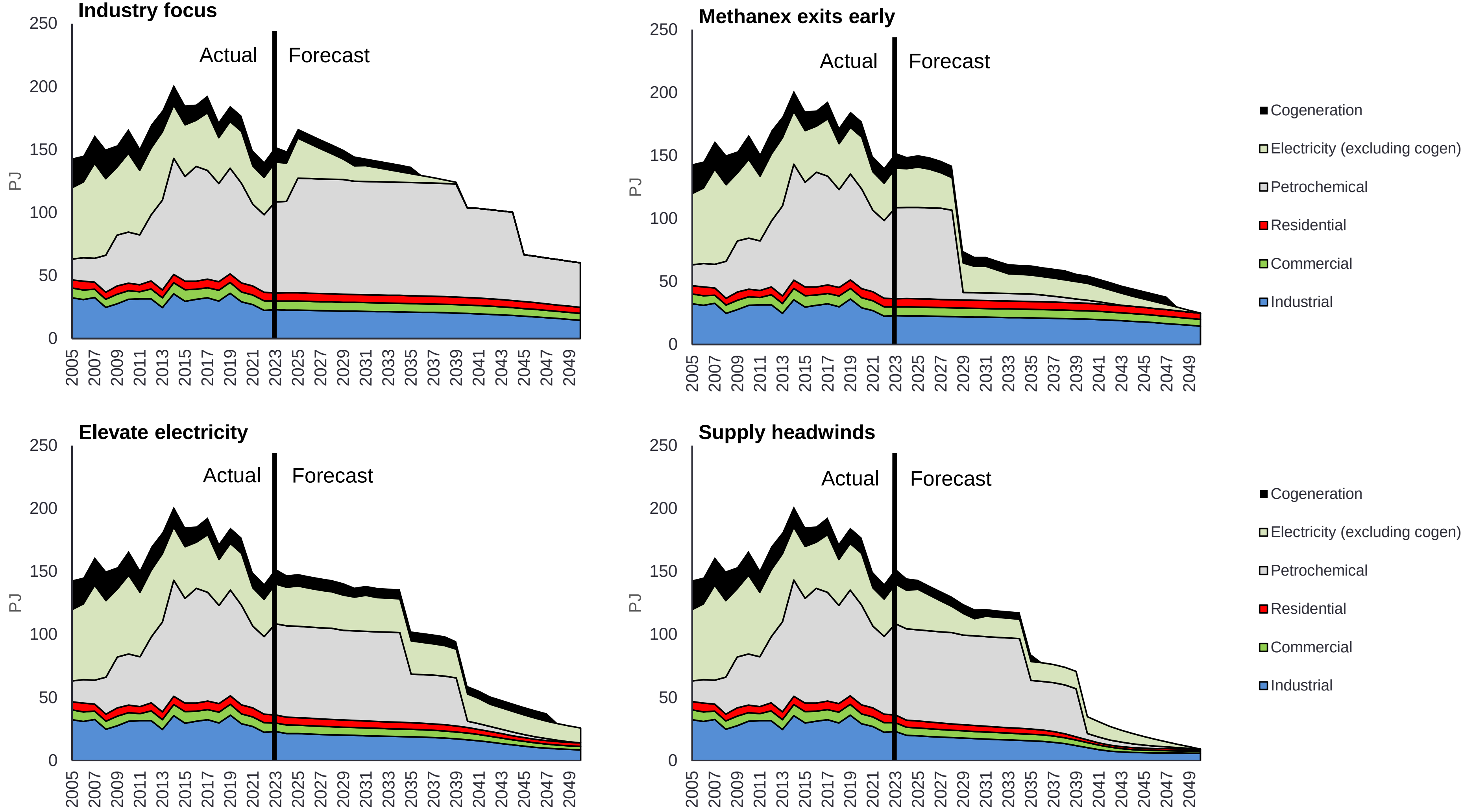

Figure 10: Gas demand forecast in all four scenarios

Table 15: Summary of gas demand by component – Industry focus scenario (PJ)

	2023	2025	2030	2035
Cogeneration	12.3	7.6	7.6	5.7
Electricity (excl. cogen)	31.4	31.8	12.2	7.0
Petrochemical	72.4	91.0	89.8	89.8
Residential	6.3	6.5	6.4	6.2
Commercial	6.9	7.1	7.0	6.8
Industrial	23.0	22.7	21.8	21.0
Total	**152.3**	**166.7**	**144.8**	**136.5**

Table 16: Summary of gas demand by component – Methanex exits early scenario (PJ)

	2023	2025	2030	2035
Cogeneration	12.3	9.5	7.6	7.6
Electricity (excl. cogen)	31.4	32.1	20.9	15.0
Petrochemical	72.4	72.4	6.0	6.0
Residential	6.3	6.5	6.4	6.2
Commercial	6.9	7.1	7.0	6.8
Industrial	23.0	22.7	21.8	21.0
Total	**152.3**	**150.3**	**69.7**	**62.6**

Table 17: Summary of gas demand by component – Elevate electricity scenario (PJ)

	2023	2025	2030	2035
Cogeneration	12.3	9.5	7.6	7.6
Electricity (excl. cogen)	31.4	32.1	26.7	26.2
Petrochemical	72.4	72.4	71.2	38.6
Residential	6.3	6.0	5.6	5.3
Commercial	6.9	6.7	6.3	5.9
Industrial	23.0	21.4	19.9	18.9
Total	**152.3**	**148.1**	**137.3**	**102.5**

Table 18: Summary of gas demand by component – Supply headwinds scenario (PJ)

	2023	2025	2030	2035
Cogeneration	12.2	7.6	7.6	5.7
Electricity (excl. cogen)	31.4	32.1	13.5	15.0
Petrochemical	72.4	72.4	71.2	38.6
Residential	6.3	5.5	4.7	4.1
Commercial	6.9	6.3	5.7	5.2
Industrial	23.0	19.6	17.4	15.6
Total	**152.3**	**143.5**	**120.1**	**84.2**

4.2 Petrochemical demand

Natural gas is an integral part of New Zealand's petrochemical industry, serving as both a fuel for process heat and as feedstock. There are two main gas consumers within the petrochemical industry, Methanex and Ballance.

Figure 11 shows the annual demand within the petrochemical sector across the scenarios. The historical demand is also shown. This has been estimated based on historical data[21] and the dates of previous openings and closures of Methanex's three different methanol trains.

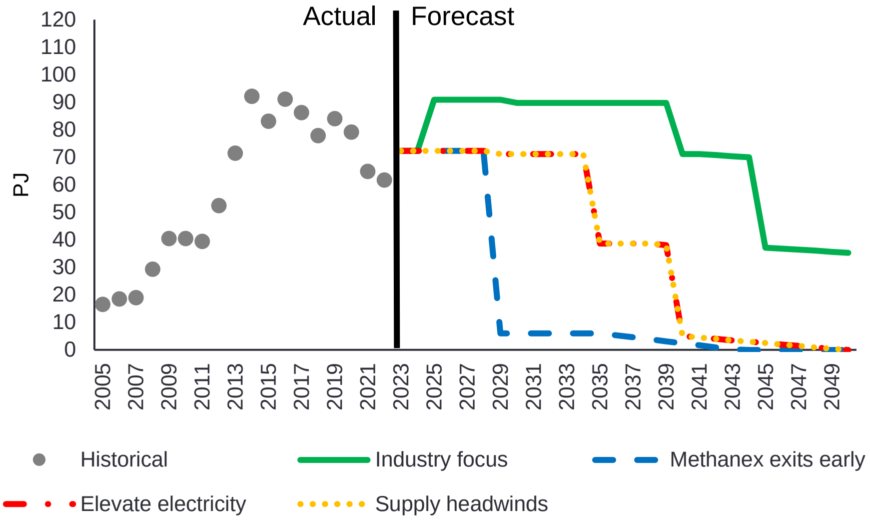

Figure 11: Total annual demand from the petrochemical sector for each of the four scenarios

4.2.1 Methanex

Methanex produces methanol which is a basic building block of plastics, paints, and synthetic fibres. Methanol is also used as both a fuel and a fuel additive. When running at maximum capacity, Methanex consumes around 90 PJ of natural gas annually[21], which is more than 50% of New Zealand's entire production in recent years. The Methanex operation is split across three production trains, Motunui 1 and 2, and Waitara Valley. The plants demand split is approximately two thirds feed gas and one third fuel gas. The Waitara Valley plant was mothballed in 2021.

Methanex is a vitally important consumer within the natural gas industry because their demand is used to underwrite investment in the supply side. They also provide demand response when supply is low.

A summary of operations from the two nearby plants in northern Taranaki is below:

1. Motunui 1 and 2 each have the capacity to produce 2,600 tonnes per day of crude methanol. The Motunui site was originally designed to produce synthetic petrol but was modified to produce methanol due to falling oil prices in the late 1990s. The combined consumption of Motunui is around 70 PJ of natural gas annually when operating at maximum capacity. The supply contract for the Motunui plants expires in 2029, although there is the potential for an early exit if supply is limited.

2. Waitara Valley has a single methanol plant with a capacity to produce 1500 tonnes per day of crude methanol. The plant was mothballed in 2021 due to a decline in the production of the Pohokura field and delays in the drilling of new wells. Methanex has said that they will maintain

[21] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/

the Waitara Valley plant in a safe condition and restart operations if supply becomes available. When operational, the Waitara Valley plant consumes up to 20 PJ of natural gas annually.

Although the mothballing of Waitara Valley is not a good sign for Methanex's New Zealand operations, it is worth noting that both Motunui and Waitara Valley have been mothballed in the past. A timeline of Motunui and Waitara Valley historical operations[22] is shown below in Figure 12.

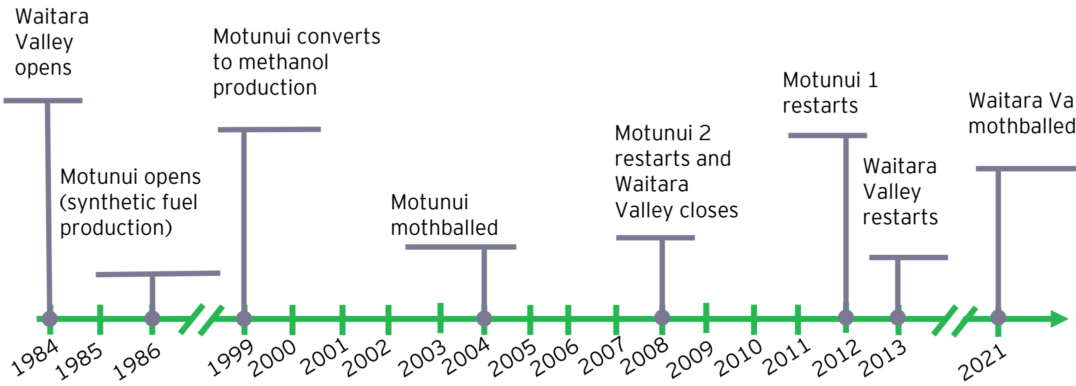

Figure 12: A timeline of the various openings and closings of the methanol (or synthetic fuel) plants

In contrast to methanol production in New Zealand, the global demand for methanol is strong and from 2018 to 2023 it has increased at a CAGR of 3%[23]. The combined production of Methanex's New Zealand plants has the capacity to account for 3% of global methanol production. The marginal global producer of methanol uses coal, rather than natural gas, which is much lower efficiency than the Waitara Valley plant and produces significantly higher greenhouse gas emissions.

The scenarios have varied the future closure dates of Motunui 1 and 2. It is assumed that Waitara Valley reopens in the *Industry focus* scenario. The assumptions are laid out in Table 19 below.

Table 19: Assumptions for the timing of Methanex closures/reopening within the scenarios

Scenario(s)	Motunui 1 closes	Motunui 2 closes	Waitara Valley reopens	Waitara Valley closes	Outcome for gas demand
Industry focus	2045	2060	2025	2040	High
Methanex exits early	2029	2029	-	-	Low
Elevate electricity	2035	2040	-	-	Medium
Supply headwinds	2035	2040	-	-	Medium

4.2.2 Ballance Agri-Nutrients

Ballance uses natural gas to produce urea, a type of nitrogen fertiliser used in agriculture, at its Kapuni plant in Taranaki. It is the only plant in New Zealand that produces urea and provides

[22] Based on private communication.
[23] https://www.methanol.org/methanol-price-supply-demand/

approximately one third of domestic urea demand. Ballance produces approximately 260,000 tonnes of urea per year, which consumes around 6.5-7.3 PJ of gas annually[24] (this varies according to a 3-year maintenance cycle).

Ballance's gas demand is used in two parts of its operations. Approximately half of its gas use is used as a source (feedstock) of hydrogen through Steam Methane Reforming (SMR) which is then combined with nitrogen to produce ammonia. The other half of Ballance's demand is used to drive its production processes, including heating of the SMR process, and driving the ammonia synthesis process.

Ballance has a decarbonisation programme to reduce its process emissions over the coming decades which consists of two phases. The first phase is to electrify the ammonia synthesis process, which would reduce its manufacturing emissions by 40-45% and demand for natural gas by 1-1.5PJ/year[25]. The second phase involves replacing the SMR (steam methane reformer) with a hydrogen electrolyser (or similar) in a staged approach. This has the potential to reduce its current manufacturing emissions by a further 50% and reduce its gas demand.

Ballance is targeting to complete phase one of its decarbonisation programme by the end of the decade. However, the investment required is significant and the economics is challenging. The timing of phase two is more uncertain as it is dependent on the progress of electrolyser technology and the economics of a significant investment in electricity infrastructure to support this change to its processes. The timing of phase one and phase two have been varied across the different scenarios. The assumptions are laid out in Table 20.

Table 20: Assumptions for the timing of Ballance's decarbonisation program within the scenarios

		Stage 2		
Scenario(s)	Stage 1 completed:	Start	Finish	Outcome for gas demand
Industry focus	2030	2042	2058	High
Methanex exits early	2028	2036	2044	Low
Elevate electricity	2029	2039	2047	Medium
Supply headwinds	2029	2039	2047	Medium

4.3 Electricity generation

Gas is a key component in New Zealand's electricity generation mix, delivering between 4.3 and 5.9 TWh per annum (11% of electricity demand) in the last 3 years[26]. While it offers a cleaner alternative to coal and diesel-fired generation, New Zealand's target of net-zero emissions by 2050 suggests it is likely to be phased down over time. However, due to the ability of open cycle gas turbines to rapidly ramp up or down, it is a natural candidate to play the crucial role of firming intermittent renewable sources of electricity (such as wind and solar).

24 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fgas.xlsx&wdOrigin=BROWSELINK

25 Private communication with Ballance

26 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/

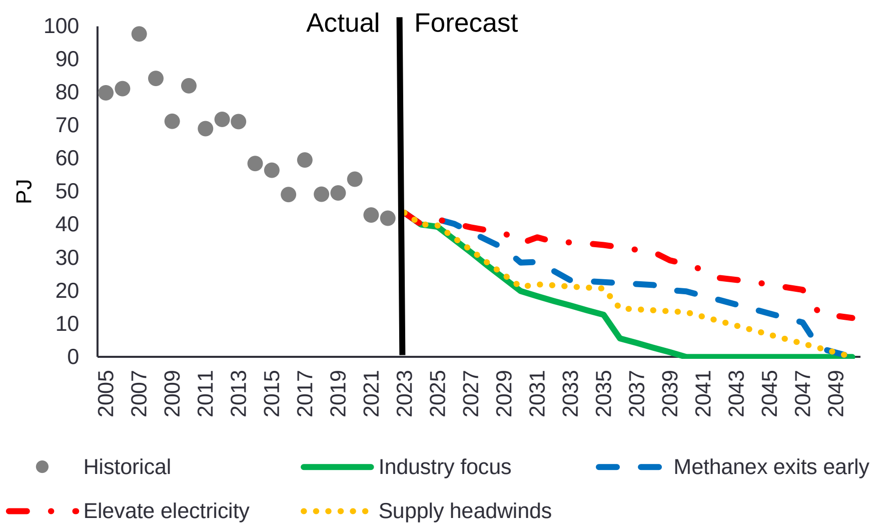

Figure 13: Total annual demand from gas-fired generation (including cogeneration) in each scenario[27]

Gas demand for electricity generation in New Zealand is made up from four key sources:

Baseload generation: Baseload refers to a near constant level of generation that sits beneath the minimum operational demand of the electricity grid. Fuel sources that provide baseload in New Zealand include coal, gas (through closed-cycle gas turbines or CCGT), geothermal, and run-of-river hydro. Thermal baseload generators typically have very high efficiency (heat rates of around 7.4 GJ of gas burned per MWh of electricity generated) but cannot be ramped up or down rapidly.

Peaking generation: Peaking refers to generation that can be rapidly ramped up or down as levels of operational demand on the electricity grid change. Fuel sources that provide peaking in New Zealand include hydro (with storage), gas (through open-cycle gas turbines or OCGT), and diesel. Peaking generation generally has lower efficiency than baseload generation (heat rates of around 10.9 GJ of gas burned per MWh of electricity generated).

Cogeneration: Cogeneration is generally attached to an industrial process facility. It captures the waste heat from the electricity generator and converts it to a productive use. Cogeneration operations are typically driven by the industrial process facility rather than in response to conditions on the grid.

Dry year cover: Because New Zealand's electricity system has more than 60% of the energy come from hydro, there needs to be something in reserve to cover for extended periods of low hydro catchment inflows. Fuel sources that provide dry year cover in New Zealand include coal, gas, and diesel. Dry year cover is unique in that it is only needed in particular years.

Figure 13 shows demand for gas from electricity generation including baseload, peaking and cogeneration demand in each of the four scenarios. It also includes a probability-weighted dry year cover across the four scenarios. Although dry year cover would not be required every year, it would need to be *available* to be able to provide this cover in any year.

Although natural gas currently provides only around 11% of total electricity generation[26], there has historically been a strong link between electricity price and natural gas price. Natural gas consumers are unlikely to find it economic to electrify until electricity prices materially reduce relative to natural gas prices. For this reason, the level of gas-fired generation in the electricity market has implications for energy economics, beyond just its own increment to demand. A

[27] The forecast data includes *demand for gas in a dry year* as a probability weighted demand in every year, whereas *demand for gas in a dry year* shows up as fluctuations in the historical data.

complete study of the energy economics, particularly the relativity between electricity and gas prices, is beyond the scope of this report.

Further detail on the assumptions for each electricity demand source (baseload, peaking, cogeneration, and dry year cover) under each scenario are provided in the following sections.

4.3.1 Baseload generation demand

Baseload generation is currently generated by the Taranaki Combined Cycle (TCC) and Huntly Unit 5 (also referred to as Huntly e3p). The TCC is due to retire in September 2024[28], which is reflected in the modelling of all scenarios. In recent years Huntly Unit 5 has generated at a capacity factor of ~77%[29] and it is assumed to continue operation in the near term, but the capacity factor and retirement date is varied by scenario. The baseline for the projected baseload demand is based on publicly released modelling from the Climate Change Commission's Demonstration Path[30] and Transpower's Whakamana i Te Mauri Hiko modelling[31], with an assumed split between baseload and peaking.

Under the *Elevate electricity* scenario, gas is prioritised for electricity generation, and this is reflected in the longer operation of Huntly Unit 5 at higher capacity factors (in alignment with the baseline projection) up to its planned retirement in 2038, when it is then assumed to be converted to a peaking unit. Under the *Methanex exits early* and *Supply headwinds* scenario, gas-fired baseload generation remains in the system for the same amount of time but there is assumed to be less dependence on baseload than the *Elevate electricity* scenario, resulting in lower capacity factors. In the *Industry focus* scenario, baseload generation is quickly replaced by renewable generation. All scenarios assume no new gas-fired baseload generation is built. The assumptions for baseload generation in each scenario are described in Table 21.

Table 21: Assumptions for baseload electricity demand

Scenario(s)	TCC	Huntly Unit 5 (Capacity Factor)
Industry focus	Retires 2024	Rapid reduction from 2025-2030 **(75% to 0%)**
Methanex exits early	Retires 2024	Moderate reduction from 2025-2033 **(75% to 0%)**
Elevate electricity	Retires 2024	Moderate reduction from 2025-2032 **(75% to 25%)** Slower reduction rate from 2032-2037 **(25% to 0%)** Converted to peaking unit in 2038 **(0% baseload)**
Supply headwinds	Retires 2024	Moderate reduction from 2025-2033 **(75% to 0%)**

The resulting demand profiles for baseload generation are illustrated in Figure 14.

[28] https://contact.co.nz/thewire/leadership/our-decarbonisation-story
[29] https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD
[30] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.climatecommission.govt.nz%2Fpublic%2FInaia-tonu-nei-a-low-emissions-future-for-Aotearoa%2FModelling-files%2FTiwai-point-sensitivity-dataset-final-advice-2021.xlsx
[31] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fstatic.transpower.co.nz%2Fpublic%2Funcontrolled_docs%2FWhakamana%2520i%2520te%2520Mauri%2520Hiko%2520data%2520report%2520figures.xlsx%3FVersionId%3DB1w9nnzgfdbvZW71kWkWhLbFay6VqZvf&wdOrigin=BROWSELINK

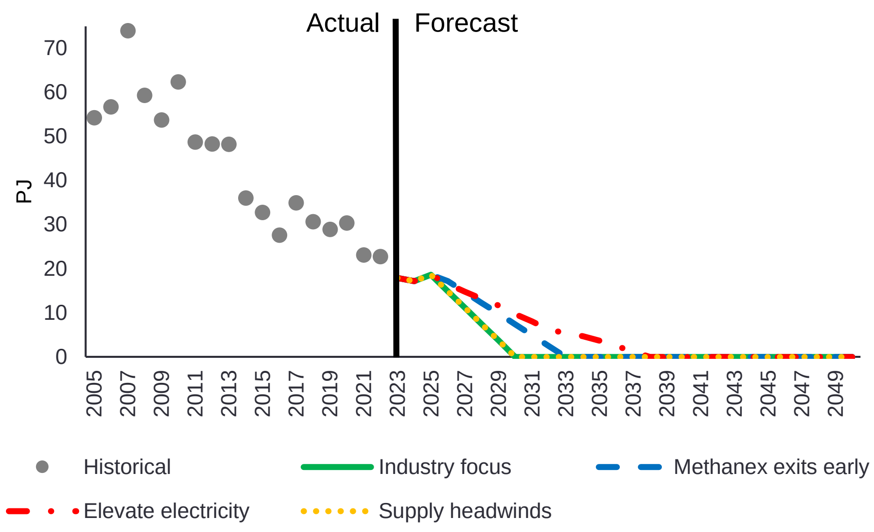

Figure 14: Total annual demand from baseload gas-fired generation for each scenario

4.3.2 Peaking generation demand

Over the past decade, Open Cycle Gas Turbine (OCGT) generators (also called "*peakers*" or "*peaking*") have generated an average of 750 GWh of electricity annually, fluctuating between approximately 550 – 1,025 GWh per year[32]. This establishes a starting requirement to ensure availability of up to approximately 1 TWh of peaking generation per year.

In the future there will be drivers which have the potential to be additive (e.g., the need for firming of intermittent renewables) or subtractive (for example through increased penetration of battery storage and demand response and/or 'overbuild' of renewable generation). The assumed balance of these additive and subtractive drivers for each scenario are described in Table 22.

Table 22: Assumptions for peaking electricity demand

Scenario(s)	Assumptions
Industry focus	Peaking demand of 1 TWh continues to 2030. Reliance on gas for peaking reduces to 0 by 2040.
Methanex exits early	Peaking demand of 1 TWh continues through to 2040. Reliance on gas for peaking reduces to 0 by 2050.
Elevate electricity	Peaking demand of 1 TWh continues to 2025. Peaking generation increases to meet the baseline generation profile in 2038. [33] Peaking generation continues to track the baseline generation profile.
Supply headwinds	Peaking demand of 1 TWh continues through to 2040. Reliance on gas for peaking reduces to 0 by 2050.

The resulting demand profiles for peaking generation are illustrated in Figure 15.

[32] https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD

[33] The 'baseline' generation profile refers to the total natural gas generation which is to be met by both baseload and peaking generation. Additional information on the 'baseline' generation profile can be found in the appendix.

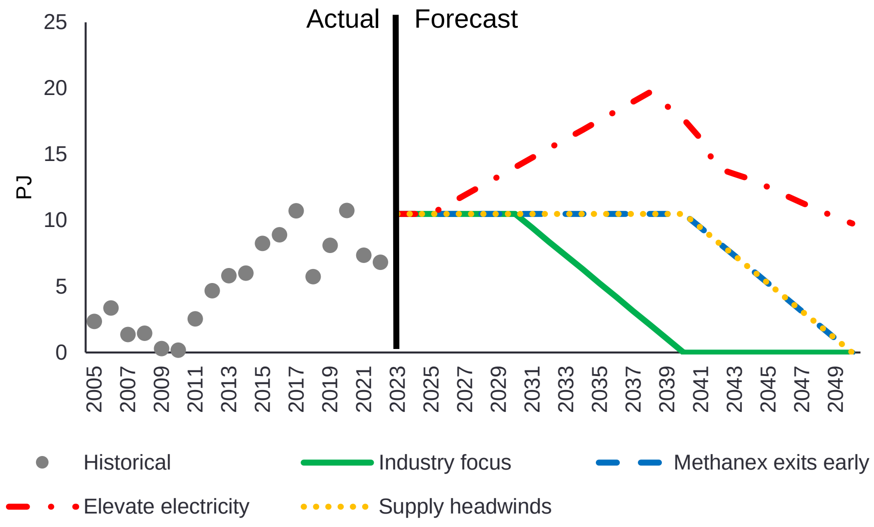

Figure 15: Total annual demand from fast-start peaking gas-fired generation for each scenario

4.3.3 Cogeneration demand

Cogeneration, unlike standard electricity generation, typically maintains a relatively stable annual output based off the heat demand for the associated processing plant. The availability and affordability of gas has the potential to impact the continued use of cogeneration at these plants, which could mean these businesses seek to reduce demand via transitioning to other energy sources or otherwise modifying their output or operations. Further to this, recent consultation on implementing a ban on new fossil fuel baseload generation is considering whether cogeneration should have an exemption or should be included in the proposed ban[34]. For this analysis, it is assumed that no new cogeneration plants are built, and existing plant are assumed to reduce their demand for gas over time as described in Table 23 until they reach their planned retirement dates.

Table 23: Assumptions for cogeneration demand

Scenario(s)	Assumptions
Industry focus	Cogeneration is reduced to 80% historical demand from 2025-2030 Demand is further reduced to 60% from 2031-2035 All cogeneration is retired by 2035
Methanex exits early	Cogeneration continues to operate at historical levels to 2029 From 2029 onwards demand is reduced to 80% of historical values Cogeneration retirements occur at the expected end of life for each plant[35]
Elevate electricity	Cogeneration continues to operate at historical levels to 2029 From 2029 onwards demand is reduced to 80% of historical values Cogeneration retirements occur at the expected end of life for each plant
Supply headwinds	Cogeneration is reduced to 80% historical demand from 2025-2030 Demand is further reduced to 60% from 2031-2035 All cogeneration is retired by 2035

[34] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/electricity-transition/implementing-a-ban-on-new-fossil-fuel-baseload-electricity-generation/
[35] Project lifetimes are taken from: https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf

The resulting demand profiles for cogeneration are illustrated in Figure 16.

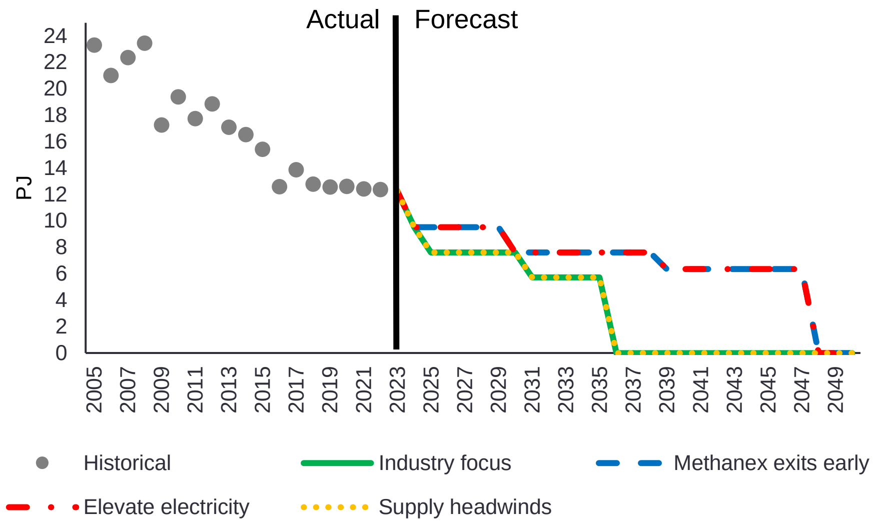

Figure 16: Total annual demand from gas-fired cogeneration for each scenario

4.3.4 Dry-year generation demand

The "*dry year*" problem refers to when the hydro-power catchments do not receive enough rainfall or snowmelt and the level of the storage lakes runs low. When this occurs some form of back-up is needed, and this is currently provided by a combination of coal, gas (if available), and diesel generation. Based on historical inflow data, this shortfall is estimated to be between 3-5 TWh. Once coal generation is retired post-2030, the shortfall will need to be met by gas-fired generation and / or a combination of storage and renewable sources[36]. For the purposes of this report, a dry year shortfall of 3 TWh and a frequency of 1-in-5 years has been assumed[37].

The starting point for all scenarios is that, in a dry year, gas would be required to be available to cover a proportion of a dry year shortfall consistent with historical use in dry years. Based on this, it is assumed that gas will meet 50% of the shortfall (1.5 TWh), and coal will meet the remaining 50% (1.5 TWh). Beyond this the assumptions vary by scenario, but dependency on gas for dry year cover generally reduces over time, with the exception of a sharp increase following the assumed cessation of burning coal at Huntly in 2031. After 2031 gas is assumed to take over coal's portion as well. The assumptions for each scenario are described in Table 24.

Table 24: Assumptions for dry year generation demand

Scenario(s)	Assumptions
Industry focus	Reliance on both coal and gas for dry year cover is phased down to 2030 Reliance on gas for dry year cover is phased out completely by 2040
Methanex exits early	Gas continues to provide dry year cover to 2030 Reliance on gas for dry year cover is phased out from 2030-2050
Elevate electricity	Gas continues to provide historical dry year cover to 2030 Reliance on gas for dry year cover is reduced to 1TWh from 2030-2050

[36] MBIE's NZ Battery project is investigating a renewable solution to the dry year problem
[37] This assumption is explained in section 1.10 of the appendix

Scenario(s)	Assumptions
Supply headwinds	Gas continues to provide dry year cover to 2030 Reliance on gas for dry year cover is phased out from 2030-2050

The resulting demand profiles for dry year generation are illustrated in Figure 17. The step change increase is due to the assumption that coal will be eliminated from electricity mix in 2030.

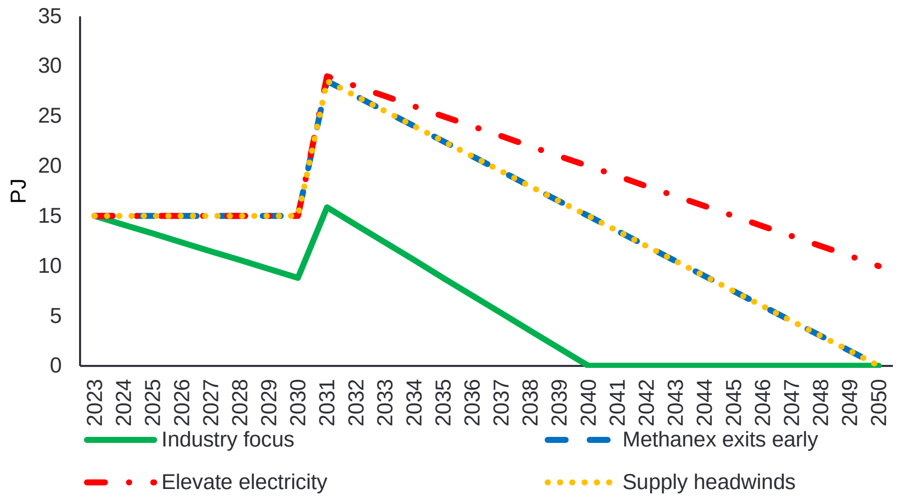

Figure 17: Additional gas demand in the event of a dry year

4.3.5 Impact of an NZ Aluminium Smelter (NZAS) exit

The NZ Aluminium Smelter at Tiwai Point consumes around 13% of NZ's annual electricity demand[38]. If the smelter were to close, around 5 TWh of electricity previously allocated to Tiwai, predominantly from the Manapouri hydroelectric power station, will be available to supply other customers and compete with gas fired generation. This is likely to reduce the need for gas-fired generation. Electricity market modelling of a Tiwai exit scenario published by the Climate Change Commission[39] shows a significant reduction in natural gas demand for electricity generation in the decade after the smelter closes. In this study, it is assumed that the smelter does not close in any of the scenarios.

4.4 Sectoral demand

New Zealand's economy relies on natural gas for a wide range of applications. Industrial, commercial, and residential sectors of the economy rely on gas for a variety of different purposes. Across the scenarios, demand for natural gas reduces for these sectors by between 10% and 25% by 2035 and by up to 73% in the longer term. This is illustrated in Figure 18.

[38] https://www.transpower.co.nz/about-us/our-strategy/whakamana-i-te-mauri-hiko-empowering-our-energy-future
[39] https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/

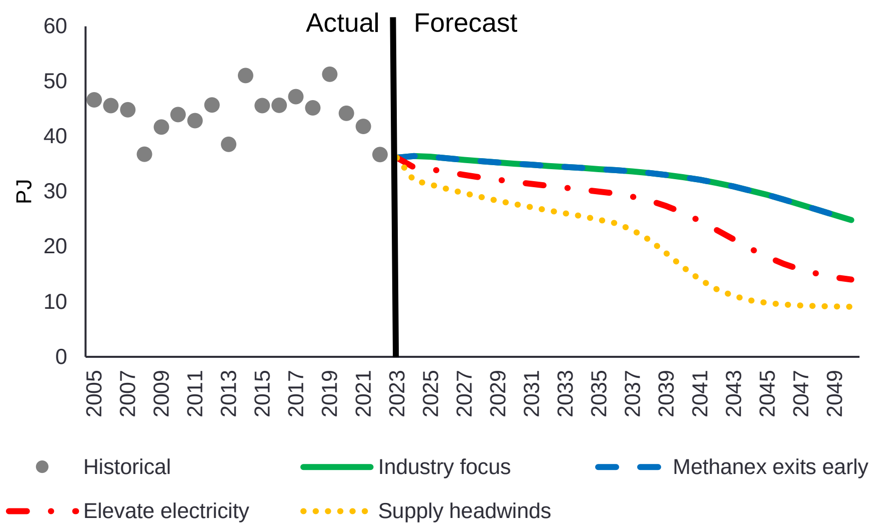

Figure 18: Total annual demand from the industrial (excluding petrochemical), commercial, and residential sectors

This section explains the underlying drivers of how gas demand is set to change among the different sectors within the economy.

4.4.1 Industrial demand (excluding petrochemical)

Industrial demand for natural gas in New Zealand (excluding the petrochemical industry) comes mainly from dairy, food, and meat product manufacturing. The largest industrial consumers include Oji Fibre Solutions, Fonterra, and New Zealand Steel. Annual gas demand in the sector was approximately 22 PJ in 2022[40].

Industrial demand is made up of 73% medium and high temperature process heat and cooking and 25% low temperature water and other heating[41]. The remainder provides motive power. This breakdown into low, medium, and high temperature end use is important because it plays a role in the physics and economics of electrification – essentially the efficiency of electric heat pumps scales as the inverse of temperature (efficiency decreases as temperature increases). From this perspective, the opportunity for electrification of industrial heat appears to be limited due to the high temperature applications.

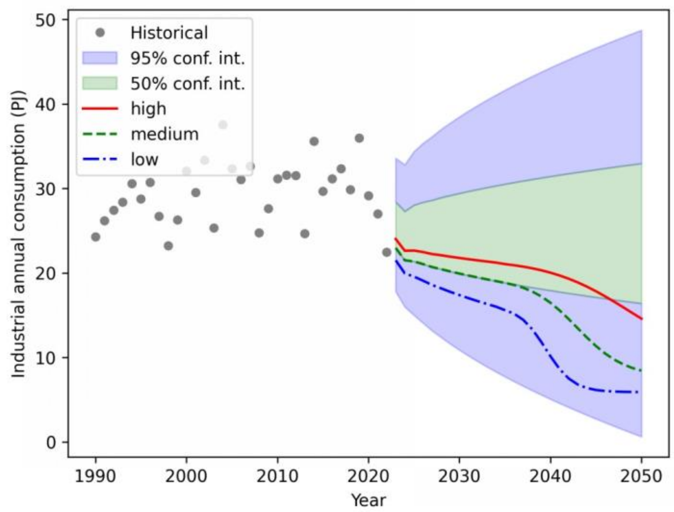

Figure 19: Annual industrial demand

[40] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fgas.xlsx&wdOrigin=BROWSELINK
[41] https://www.eeca.govt.nz/insights/eeca-insights/energy-end-use-database-eeud/

Fonterra is focused on reducing their greenhouse gas emissions through their commitment to stop using coal by 2037[42]. It has not, as yet, signalled an intention to reduce its demand for natural gas. It is however likely that their natural gas consumption will begin to reduce beyond 2035 once coal is phased out and there is a greater spotlight on emissions from natural gas. Fonterra consumed an estimated 4.4 PJ of gas[43] in 2022.

New Zealand Steel is similarly focused on reducing their coal consumption. They have announced plans to install an electric arc furnace that will replace the existing steelmaking furnace and two of the four coal-fuelled kilns. Furthermore, NZ Steel is exploring the use of natural gas as a transitional hydrogen source. Hydrogen produced DRI (direct reduced iron) can be achieved initially via natural gas before transitioning to green hydrogen as the market develops. Natural gas would allow a full transition away from using coal in the ironmaking process. NZ Steel consumed an estimated 1.8 PJ of gas in 2022[43].

Oji Fibre solutions use natural gas at the Kinleith, Tasman, and Penrose Mills. Kinleith is the largest mill and consumed an estimated 2.8 PJ of gas in 2022[43]. The Tasman and Penrose mills consumed less than 1 PJ in 2022[43]. Oji's total energy use is approximately 77% renewable[44] with significant use of geothermal heat from the Kawerau geothermal field. Their natural gas use is for high temperature process heat requirements, for which alternative fuels are likely to be prohibitively expensive. They do not expect to materially reduce their natural gas consumption beyond an organic reduction in demand through incremental energy efficiency improvements.

Prior to closing in April 2022, the Marsden Point Oil refinery consumed around 4 PJ of gas annually[43].

By fitting a statistical regression model to historical data it is observed that industrial demand for gas is neither trending up nor down but staying reasonably static. However, there are reasonably significant fluctuations in demand. The statistical regression model tells us that the forecast for industrial demand is dominated by uncertainty rather than a discernible trend. The shaded areas in Figure 19 illustrate the 50% and 90% confidence intervals from the regression model. The expected forecast from the regression model (which is not shown in the figure) is flat[45].

In summary, three key indicators suggest the industrial demand for natural gas is unlikely to dramatically reduce prior to 2035:

1. The physics and economics of electrification is challenging due to the medium and high temperature requirement of industrial processes.

2. Major industrial consumers have not announced plans to reduce their demand for natural gas.

3. Regression analysis on historical industrial demand data shows no clear decreasing trend.

Considering these indicators, this study has assumed small to modest reductions in industrial gas demand out to 2035. This study assumes reductions in high temperature process heat of 10%, 24%, and 50%, and reductions in medium temperature process heat of 4%, 13%, and 14% by 2035 in the low (*Supply headwinds*), medium (*Elevate electricity*), and high (*Industry focus* and *Methanex exits early*) scenarios, respectively. These assumptions are laid out in Table 25.

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[42] https://www.rnz.co.nz/news/country/494089/government-partners-with-fonterra-to-cut-coal-use-and-halve-manufacturing-emissions#:~:text=Fonterra%20plans%20to%20stop%20using%20coal%20by%202037.,its%20ambition%20to%20be%20net%20zero%20by%202050.

[43] https://www.gasindustry.co.nz/data/gas-production-and-consumption/

[44] Discussions with Oji Fibre solutions and sustainability report: https://cdn.sanity.io/files/gz4vq3tx/production/c4a349575740bc04877910991b681bd5a39cf317.pdf

[45] In this study, industrial demand includes agricultural, forestry, and fisheries demand but excludes petrochemical demand. The grey dots show historical demand, the solid red, dashed green, and dash-dotted blue lines show high, medium, and low demand respectively.

Beyond 2035, a structural break in historical trends has been modelled. This is because removing combustion emissions from natural gas will take on greater urgency due to higher carbon costs and greater technology availability. This is done using a model that quantifies the uptake of innovation, known as the Bass diffusion model. The innovation uptake model assumes different uptake rates and does not reduce gas demand to zero. Rather, it saturates at an assumed long-term target level shown in Table 25. The scenarios show some demand for high and medium temperature process heat remaining, particularly where opportunities for CCUS might exist.

The final forecasts for industrial gas demand (overlaid with the statistical regression model) are shown in Figure 19.

Table 25: Assumptions for target reductions for industrial end-use

	2035 (long term, in brackets) reduction target for industrial:			
Scenario(s)	High temp. heat	Medium temp. heat	Low temp. heat	Outcome for gas demand
Industry focus	10% (60%)	4% (75%)	2% (85%)	High
Methanex exits early	10% (60%)	4% (75%)	2% (85%)	High
Elevate electricity	24% (70%)	13% (80%)	7% (90%)	Medium
Supply headwinds	50% (80%)	14% (90%)	8% (95%)	Low

4.4.2 Commercial demand

Commercial demand for natural gas in New Zealand comes from a diverse set of consumers ranging from providers of accommodation, health care, wholesale and retail trade, arts and recreational services, education, and business services. Annual demand in the sector was approximately 7.4 PJ in 2022[46].

Commercial demand for natural gas is made up of 86% low temperature space (75%) and water (11%) heating. Medium temperature heat for cooking makes up 10% of demand[47]. From this perspective, the opportunity to reduce commercial demand for gas through electrification appears promising, particularly for the low temperature space heating. However, the focus is on reducing coal demand first.

Commercial demand is much less concentrated than industrial demand. There are many mid-size and smaller consumers, each with their own set of drivers for decision making and some of whom may have sizable demand for coal. For this reason, it is difficult to gauge the likelihood of any collective reduction in gas demand.

By fitting a statistical regression model to historical data, it is seen that commercial demand for gas was trending upward but has effectively plateaued since 2004. Very recently (2020 to 2022) demand has dropped which is consistent with reduced economic activity in the wake of the COVID-19 pandemic. The statistical regression model tells us that the forecast for commercial demand is dominated by uncertainty rather than a discernible trend. This is illustrated as the shaded area in Figure 20.

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[46] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fgas.xlsx&wdOrigin=BROWSELINK
[47] https://www.eeca.govt.nz/insights/eeca-insights/energy-end-use-database-eeud/

In summary, three key indicators suggest a complex and uncertain future for commercial natural gas demand, even in the relatively near term out to 2035:

1. The physics and economics of electrification is promising with 75% of demand used for low temperature space heating.

2. The sector is dilute and made up of diverse consumers. This may make it difficult to coordinate demand reduction through a GIDI type programme.

3. Regression analysis on historical industrial demand data shows no clear decreasing trend.

In light of these considerations, this study assumes modest reductions in commercial gas demand out to 2035. The scenarios assume reductions in space heating of 10%, 23%, and 33%, and reductions in water heating of 9%, 26%, and 43% by 2035 in the low (*Supply headwinds*), medium (*Elevate electricity*), and high (Industry focus and *Methanex exits early*) scenarios. These assumptions are laid out in Table 26.

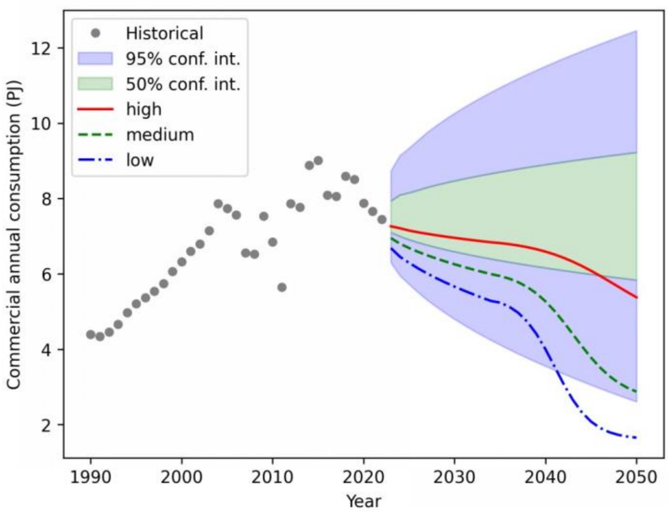

Figure 20: Annual commercial demand.

Beyond 2035, a structural break in historical trends has been modelled. This is because removing combustion emissions from natural gas takes on greater urgency. This is done using the Bass diffusion model, as for the industrial sector. The innovation uptake model assumes different uptake rates and does not reduce gas demand to zero. Rather, it saturates at an assumed long-term target level shown in Table 26. The scenarios see some demand for water heating and cooking remain, particularly where biomethane options are available.

Table 26: Assumptions for target reductions for commercial end-use

	2035 (long term, in brackets) reduction target for commercial:			
Scenario(s)	Medium temp. heat (cooking)	Low temp. heat (space)	Low temp. heat (water)	Outcome for gas demand
Industry focus	0% (0%)	10% (50%)	9% (20%)	high
Methanex exits early	0% (0%)	10% (50%)	9% (20%)	high
Elevate electricity	0% (0%)	23% (80%)	26% (40%)	Medium
Supply headwinds	0% (0%)	33% (95%)	43% (60%)	Low

4.4.3 Residential demand

Around 290,000 New Zealand homes use natural gas for hot water heating, cooking, and space heating. Annual demand was approximately 6.8 PJ in 2022[48].

Residential demand for natural gas is made up of 55% for low temperature space heating, 41% for water heating, and 4% for medium temperature cooking[49]. The space heating is particularly amenable to electrification through the installation of heat pumps. This comes with a material upfront capital cost but provides a reasonable payback over time through reduced operating costs. Using electricity for water heating has the downside of needing to keep the water at a high temperature rather than heating as required. Gas is a very popular choice for cooking and many people will be reluctant to switch to electricity, particularly if a renewable gas (such as biomethane) is available.

By fitting a statistical regression model to historical data, it is seen that residential demand for gas was trending upward but has effectively plateaued since 2000. The statistical regression model tells us that the forecast for residential demand is dominated by uncertainty rather than a reliable trend. This is illustrated as the shaded area in Figure 21.

In summary, two key indicators suggest a complex and uncertain future for residential natural gas demand, even in the relatively near term out to 2035:

1. The physics and economics of electrification is somewhat promising with 55% of demand used for low temperature space heating.

2. Regression analysis on historical industrial demand data shows no clear decreasing trend.

In light of these considerations, this study assumes modest to significant reductions in industrial gas demand out to 2035. The scenarios assume reductions in space heating of 15%, 33%, and 50%, and reductions in water heating of 0%, 10%, and 30% by 2035 in the low (*Supply headwinds*), medium (*Elevate electricity*), and high (*Industry focus* and *Methanex exits early*) scenarios. These assumptions are laid out in

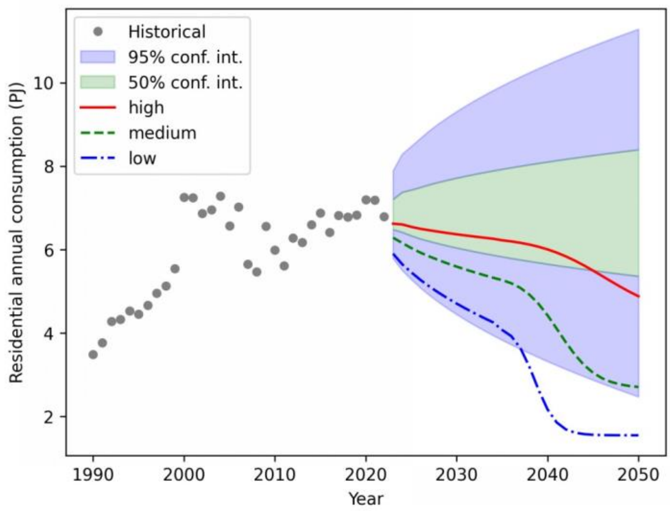

Figure 21: Annual residential demand

Beyond 2035, a structural break in historical trends has been modelled. This is because removing combustion emissions from natural gas takes on greater urgency. This is done using a model that quantifies the uptake of innovation, known as the Bass diffusion model. The innovation uptake model assumes different uptake rates and does not reduce gas demand to zero. Rather, it saturates at an assumed target level shown in Table 27. The scenarios see some demand for water heating and cooking remain, particularly when biomethane options are available.

The final forecast for residential gas demand (overlaid with the statistical regression model) is shown in Figure 21.

Table 27: Assumptions for target reductions for residential end-use

[48] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fgas.xlsx&wdOrigin=BROWSELINK
[49] https://www.eeca.govt.nz/insights/eeca-insights/energy-end-use-database-eeud/

	2035 (long term, in brackets) reduction target for residential:			
Scenario(s)	Medium temp. heat (cooking)	Low temp. heat (space)	Low temp. heat (water)	Outcome for gas demand
Industry focus	0%	15% (50%)	0% (20%)	high
Methanex exits early	0%	15% (50%)	0% (20%)	high
Elevate electricity	0%	33% (80%)	10% (40%)	Medium
Supply headwinds	0%	50% (95%)	30% (60%)	Low

5. Modelled gas supply

In order to understand conventional gas supply potential and how demand could be met by supply, this study has undertaken a bottom-up approach to supply modelling of gas from conventional fields. This has taken into account published information on gas reserves and resources, operator information on field development and lead times for bringing additional gas production on stream. From this information an 'unconstrained gas supply profile' has been produced. The demand profile built up in the previous section has then been used to modify this supply profile to match supply and demand and understand what supply would need to be from alternative sources (biomethane, hydrogen and LNG) if demand were to be met in full. This has formed the supply outlook for each of the scenarios.

This section outlines the outlook for natural gas supply, biomethane, hydrogen and LNG and then present the modelled gas supply scenarios.

5.1 Natural gas supply

5.1.1 Existing fields and production context

There are currently 22 petroleum mining permits producing gas in Taranaki through 12 production stations connected to the transmission network (receipt points)[50]. The first discoveries of natural gas date back to 1959 with Kapuni, which started production in 1970. The Maui field came onstream in 1979 and these two fields continue to produce. Further major production came onstream in the 1990s and 2000s with Turangi, Mangahewa, Kupe and Pohokura. All data for field reserves/resources, permits and operator details has been taken from annual reserves data published by MBIE in July 2023[51].

The last major field to come onstream was Kupe in 2009 and current 2P reserves[52] are, on average 85% produced as shown in Figure 22 below. Reserves refer to known accumulations of petroleum that are commercial to produce. 2P reserves (proven + probable) are reserves that have a 50% probability of being able to be produced. Annual production in 2022 was 143 PJ with daily average deliverability of 392 TJ/d. As can be seen from the data on production in Table 28 below, Pohokura, Maui and Mangahewa provide around 60% of production, Kupe, Turangi and Kapuni provide a further 35% of production while other fields contribute significantly lower amounts. Given the relative maturity of all the main producing fields, gas supply is likely to decline without investment into bringing 2C resources into production.

However, it should also be noted that the 2P reserves estimate is the production value with a 50% probability of occurrence base on the operator's plans for the field. The range of production could be higher or lower. The range of remaining production for each field Is shown in Figure 23. The 1P (proven) reserves estimate has a 90% probability of being produced, while the 3P (proven + probable + possible) reserves estimate has a 10% probability of being produced based on current operator plans.

[50] https://data.nzpam.govt.nz/permitwebmaps/?commodity=petroleum

[51] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fpetroleum-reserves.xlsx

[52] As defined by the Society for Petroleum Engineers, Petroleum Resource Management System: https://www.spe.org/en/industry/reserves/

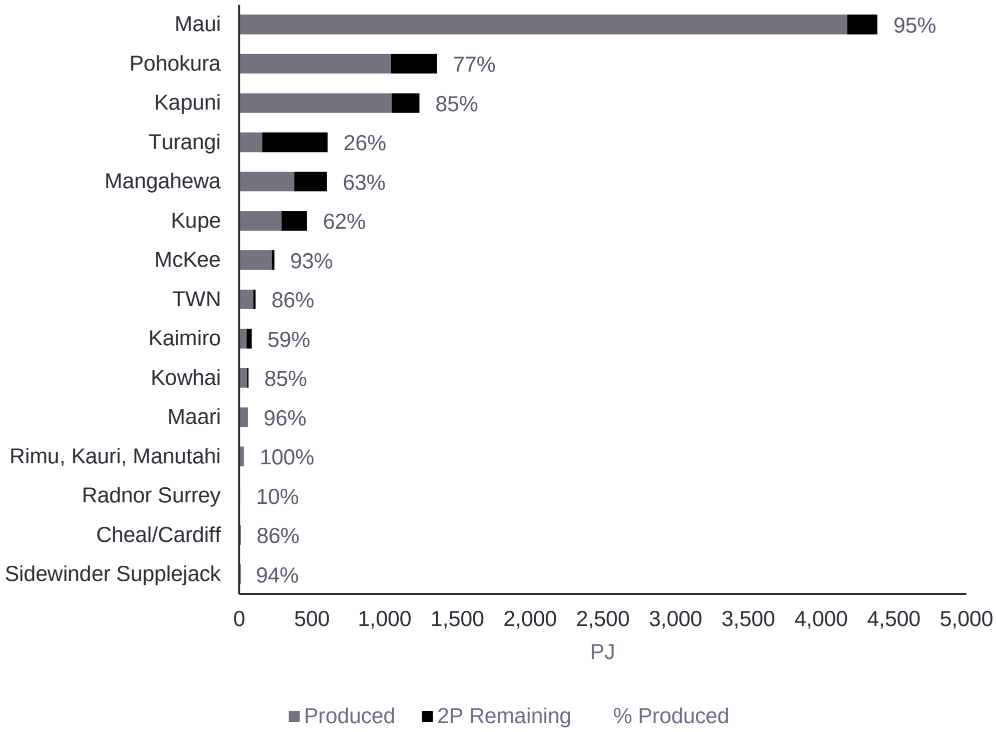

Figure 22: Production and 2P remaining reserves with percentage of 2P reserves produced as at 1 January 2023[53]

Table 28: 2022 gas production by field[54]

	PJ	TJ/d	% of Total Production
Pohokura	33.2	90.9	23%
Maui	27.5	75.4	19%
Mangahewa	26.6	72.9	19%
Kupe	19.6	53.7	14%
Turangi	17.0	46.7	12%
Kapuni	13.8	37.7	10%
McKee	2.5	7.0	2%
Kowhai	1.0	2.9	1%
Kaimiro	0.8	2.2	1%
Maari	0.6	1.7	0%

[53] Note that the reported 2P remaining and Ultimate Recoverable figures from the MBIE reporting are used as the basis for this chart. The 2P reported figure differs from the sum of the 2P production profile reported in the MBIE figures. The 2P production profiles have been used as the basis of supply modelling.
[54] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fgas.xlsx

	PJ	TJ/d	% of Total Production
Cheal/Cardiff	0.3	0.8	0%
Rimu, Kauri, Manutahi	0.1	0.3	0%
Sidewinder Supplejack	0.1	0.2	0%
TWN	0.0	0.1	0%
Radnor Surrey	0.0	0.0	0%
	143.2	392.4	

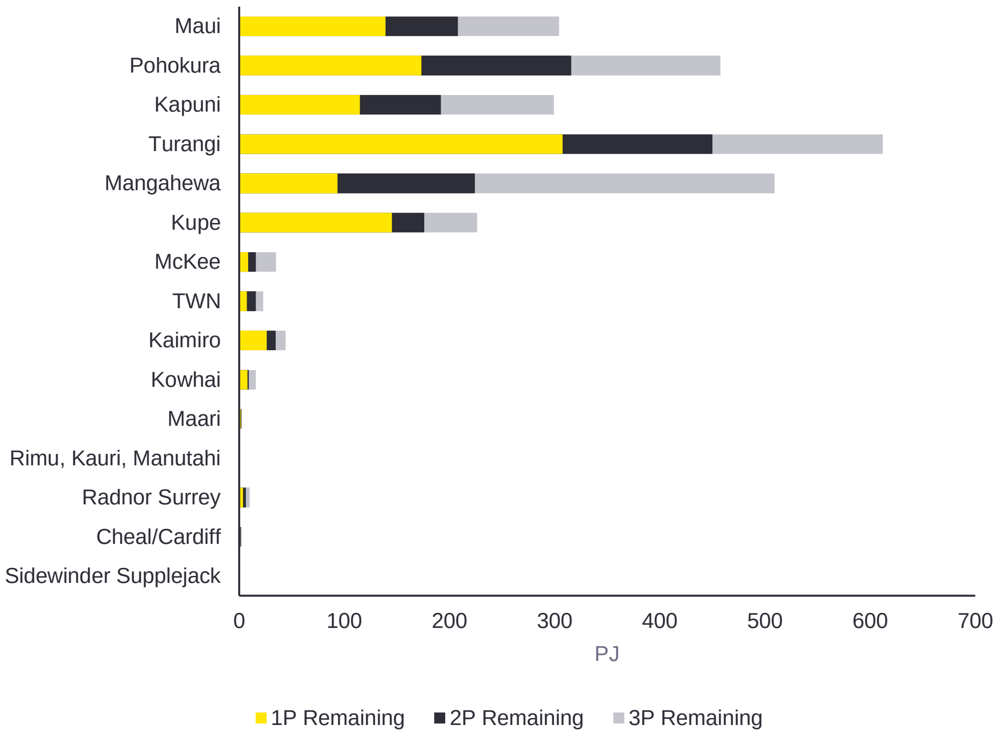

Figure 23: Remaining reserves range by field as at 1 January 2023

In terms of the economics of the producing fields, many are supported by oil and condensate production, with gas being an associated product. Hence new investment is not solely dependent on gas demand. However, all fields require continued investment to combat natural decline and these investments have a long lead time. Operators report a minimum of 3 years to obtain resource consents for drilling. Further lead time will be required for offshore drilling where drilling rigs are more costly and specialised. Offshore drilling campaigns generally require multiple wells to justify bringing a rig to New Zealand.

In previous decades the amount of activity and number of operators allowed field operators to share rigs (and therefore mobilisation/demobilisation costs) but this is no longer as feasible given the decreased level of activity. Figure 24 shows the number of wells drilled over the last two decades and the significant decline since 2015. While some reduction in activity in the last 3 years could be related to COVID-19, no exploration wells have been drilled since 2020 and drilling has been development-focused during this time. While this data includes oil-focused drilling, the trend is likely to hold across all hydrocarbon activity.

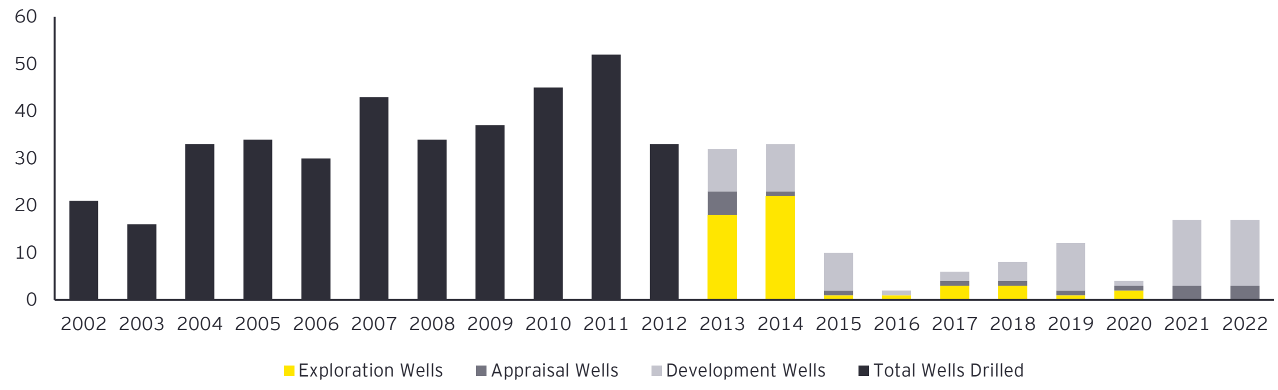

Figure 24: Wells drilled each year by type of well[55]

Similarly, the acquisition of seismic data, which can be used to identify drilling targets has slowed substantially as shown in Figure 25 and Figure 26.

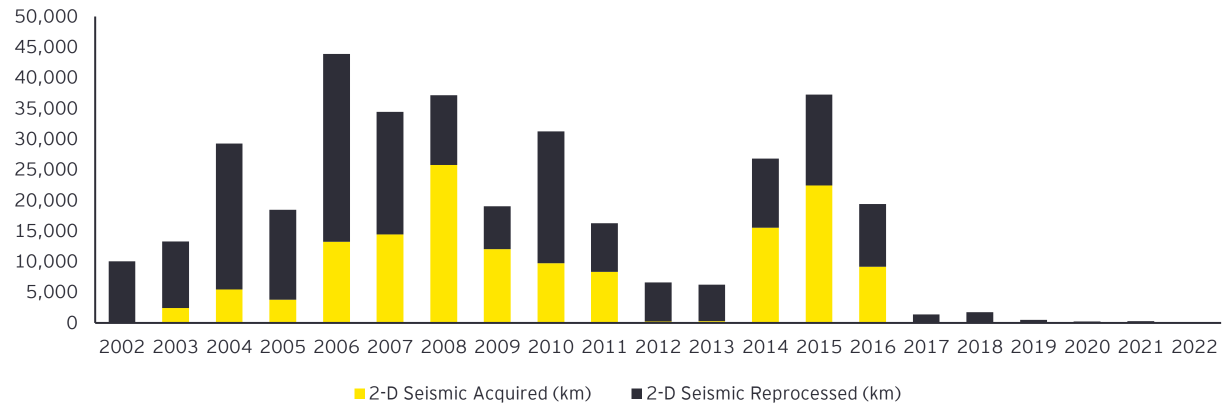

Figure 25: 2D seismic activity per year (km)[55]

55 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fpetroleum-reserves.xlsx
Note that, prior to 2013 wells were not reported split by type of well

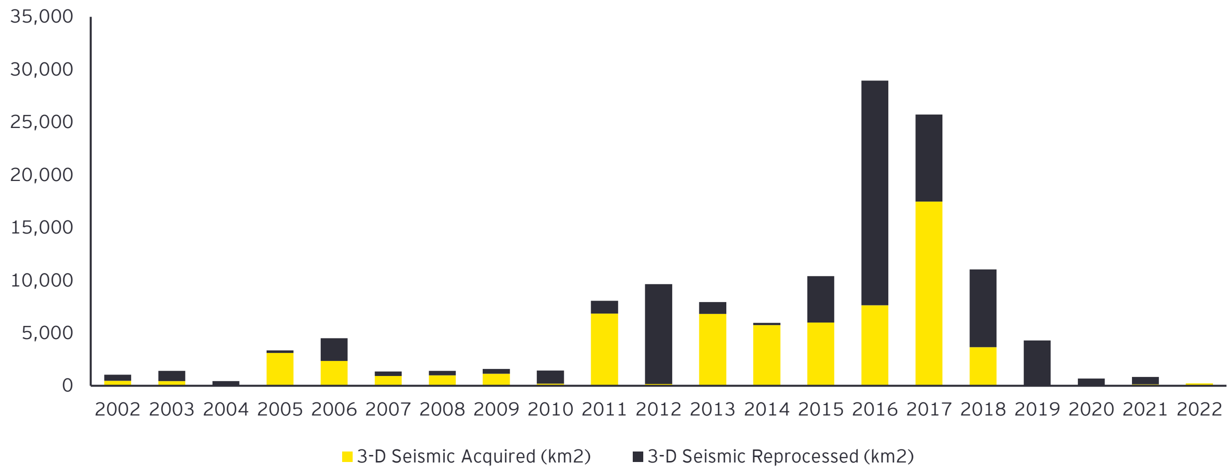

Figure 26: 3D seismic activity per year (km2)[56]

Finally, the number of active permits has declined over the same time period as shown in Figure 27. Moreover, the composition of the permits has changed from predominantly exploration-led (PEP and PPP) to being focused on existing production (PMP and PML). The restrictions on new exploration permits introduced in 2018 will have impacted the number of permits issued as new block offer rounds were not able to offer exploration acreage outside onshore Taranaki. This restriction has naturally limited supply of new permits for exploration. Current National Party policy is to repeal the 2018 ban on new offshore exploration permits[57]. The impacts of this policy change are uncertain at the time of writing. It is likely that any impacts will take time to develop due to lead times on legislative change and private sector reactions to those changes.

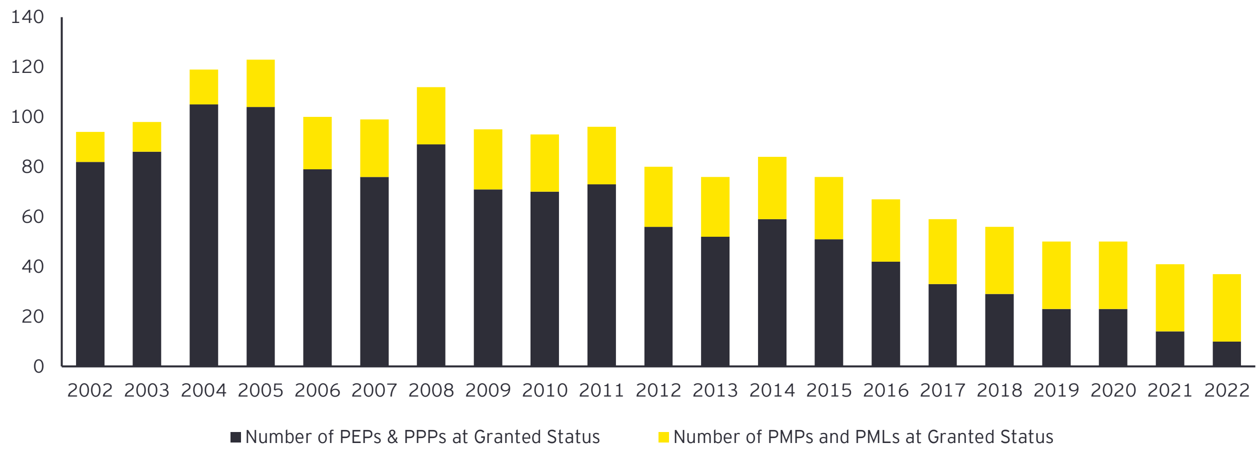

Figure 27: Number of permits at granted status

The trend across this data is that operators are focusing activity on activities on existing production permits. Exploration activity is diminishing and therefore supply additions are becoming less likely. In discussions with operators, consent timeframes and uncertainty over the regulatory regime (in particular decommissioning liability) was constraining their ability to sanction projects and take on

[56] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.mbie.govt.nz%2Fassets%2FData-Files%2FEnergy%2Fnz-energy-quarterly-and-energy-in-nz%2Fpetroleum-reserves.xlsx

[57] https://d3n8a8pro7vhmx.cloudfront.net/nationalparty/pages/14860/attachments/original/1600650042/Energy_and_Resources_Policy.pdf?1600650042

risk. Furthermore, overall trends by finance institutions to limit investment in fossil fuel operations made financing of operations more challenging.

5.1.2 Potential future natural gas supply

Potential future production in the modelling has been represented by the 2C resource[58] reported by field operators as shown in Figure 28 below. Resources are identified petroleum accumulations that are not yet commercial to produce. 2C refers to a 50% probability that the resource will meet or exceed the amount stated. Reporting of resources is more nuanced than report of reserves as data is less certain. Hence the potential for these resources to be produced is uncertain. The timing and amount of production will be heavily dependent on the operator building understanding of the subsurface sufficient to technically de-risk production while establishing a pathway to commercialisation. This can take many years and will always require significant investment.

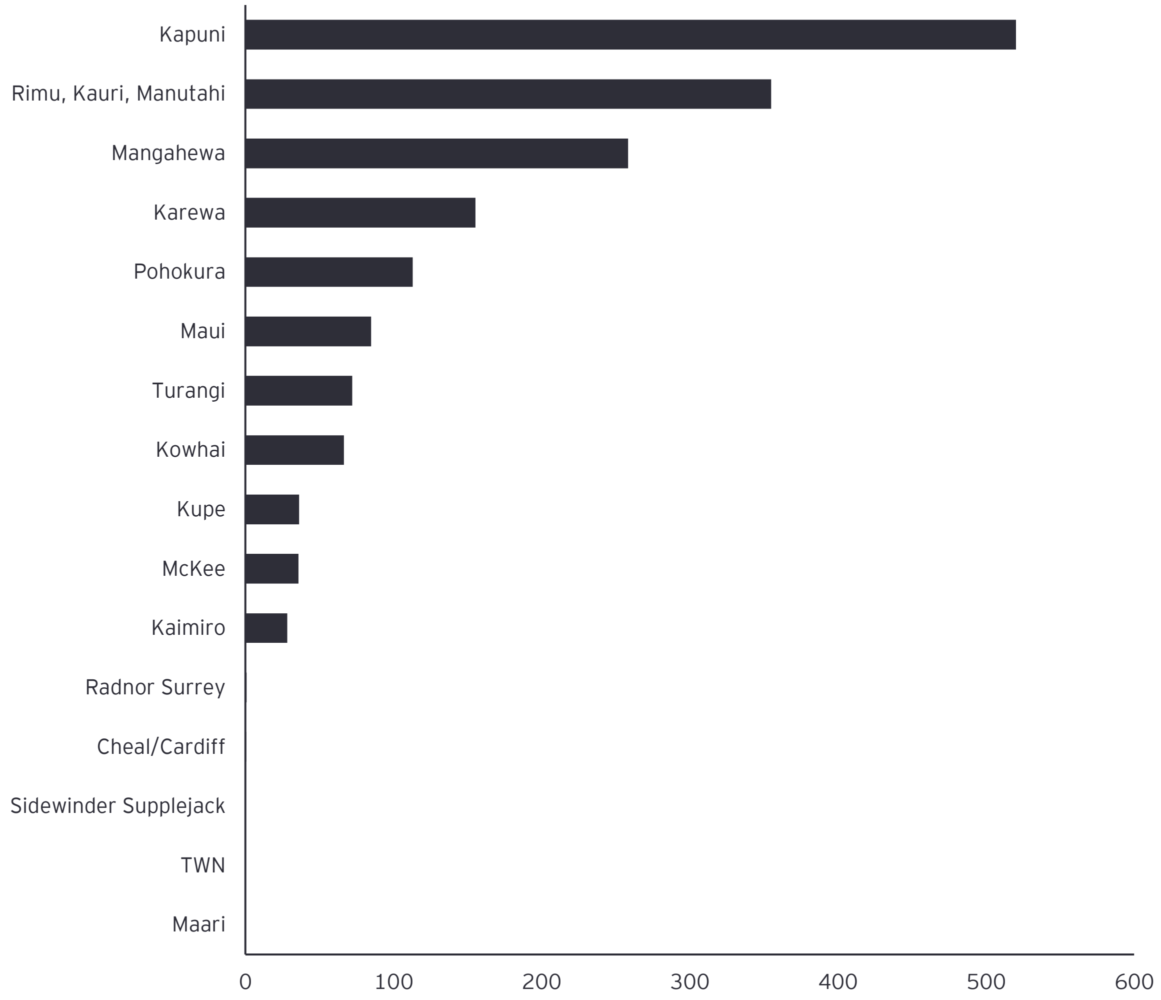

Figure 28: 2C resources by field

As outlined in the discussion in section 5.1.2, continued field investment is required to maintain production from existing reserves. More extensive time and investment is required to convert resources into reserves if this is possible. Some resources will always be too costly to produce. Field operators therefore seek to build understanding of the resource base through continually

[58] As defined by the Society for Petroleum Engineers, Petroleum Resource Management System: https://www.spe.org/en/industry/reserves/

capturing data and developing models of the resource to form a view if resources can be economically produced. There is a substantial lead time on these activities.

More prospective resources have been considered through separate analysis in Section 5.4.1.

5.1.3 Field supply outlooks

In order to model gas supply, the reserves data published annually by MBIE has been used as a starting point. This data gives a production profile for 2P reserves and totals for 2C resources. This data has been supplemented through discussions with operators to produce the field supply outlooks in Table 29 below.

Table 29: Field supply outlooks

Field					Supply Narrative
Kupe	Operator:	Beach Energy	Permit Expiry:	2031	Kupe is a mid-life asset undergoing further development drilling to maintain plateau. The inlet compression programme in 2020 maintained field deliverability and the current KS-9 (due to complete in December 2023) continues this programme. This well will secure 2P deliverability, but further drilling will need to be sanctioned to secure conversion of 2C resources. This will be difficult due to consenting timeframes and the need to contract a rig for a single well programme with limited potential to share costs with other offshore operators in NZ.
	Location:	Offshore	First Production Year:	2009	
	Production Type:	Oil/ Condensate/ LPG/ Gas	Remaining 2P Reserves (PJ):	176	
			2C Resources (PJ):	36.2	
Cheal/Cardiff and Cheal East	Operator:	Matahio Energy	Cheal and Cardiff		Cheal, Cardiff and Cheal East are oil producing fields onshore located near Stratford. The fields produce a small amount of gas which is exported to the pipeline (<0.5 TJ/d).
	Location:	Onshore	Permit Expiry:	2027	
	Production Type:	Oil/Gas	First Production Year:	2006	
			Remaining 2P Reserves (PJ):	1	
			2C Resources (PJ):	0.4	
			Cheal and Cardiff		
			Permit Expiry:	2037	
			First Production Year:	2006	
			Remaining 2P Reserves (PJ):	0.4	
			2C Resources (PJ):	0.2	
Sidewinder Supplejack	Operator:	Matahio Energy	Sidewinder		Sidewinder and Supplejack fields are oil producing fields onshore located near Inglewood. The fields produce a small amount of gas which is exported to the pipeline via the Norfolk mixing station (<0.5 TJ/d). The Supplejack field has been depleted and all remaining reserves/resources are attributed to the Sidewinder field.
	Location:	Onshore	Permit Expiry:	2030	
	Production Type:	Oil/Gas	First Production Year:	2011	
			Remaining 2P Reserves (PJ):	0.4	
			2C Resources (PJ):	0.1	
			Supplejack 2027		
			Permit Expiry:	2027	
			Remaining 2P Reserves (PJ):	0	
			2C Resources (PJ):	0	

Field					Supply Narrative
Rimu, Kauri, Manutahi	Operator:	Westside Corporation	Rimu		The Rimu, Kauri and Manutahi fields are established oil production assets with largely depleted gas reserves. Produced gas is consumed at the field. 2C resources have been identified in the form of gas associated with a new oil play in the Kauri reservoir. This is a large development and partners would need to be identified alongside consenting and other regulatory activities. The timeframe for this project development is over 5 years but production could be exported to the grid using the existing production facilities.
	Location:	Onshore	Permit Expiry:	2032	
	Production Type:	Oil/ Condensate/ LPG/ Gas	First Production Year:	2002	
			Remaining 2P Reserves (PJ):	0	
			2C Resources (PJ):	201.8	
			Kauri/Manutahi 2035		
			Permit Expiry:	2035	
			Remaining 2P Reserves (PJ):	0	
			2C Resources (PJ):	153	
Maari	Operator:	OMV	Permit Expiry:	2027	Gas is flared. Not produced to the pipeline.
	Location:	Offshore	First Production Year:	2009	
	Production Type:	Oil/ Gas	Remaining 2P Reserves (PJ):	2.1	
			2C Resources (PJ):	0	
Pohokura	Operator:	OMV	Permit Expiry:	2036	The Pohokura field came off plateau in 2020 after 14 years of production. Production is now constrained by well potential. As the production station is onshore and facilities are operated unmanned , there is flexibility to operate economically at lower fixed cost so production can continue at lower rates. Remaining reserves and resources are being developed through infill drilling of the reservoir. While production facilities are sized for 238 TJ/d, production is unlikely to reach this level again due to reservoir performance, and facilities turndown opportunities will continue through field life. OMV is preparing for drilling an additional onshore infill well in H2 2024.
	Location:	Offshore/ Onshore	First Production Year:	2006	
	Production Type:	Condensate/ Gas	Remaining 2P Reserves (PJ):	315.9	
			2C Resources (PJ):	113	
Maui	Operator:	OMV	Permit Expiry:	2036	The Maui field is a world-class giant reservoir that has underpinned gas supply in NZ since 1979 and allowed for the development of the synthetic fuels plant at Motunui and Huntly power station. It's reservoir properties (with permeability of several Darcies) have meant it could produce flexibly for many decades. However, the late life of these assets and higher cost of running offshore facilities meant that further production potential is limited. At this point decommissioning is envisaged within the next 10 years. OMV is currently in a divestment process potentially selling its assets in NZ and Malaysia and a new operator would define investment priorities going forward.
	Location:	Offshore	First Production Year:	1979	
	Production Type:	Oil/ Condensate/ LPG/ Gas	Remaining 2P Reserves (PJ):	207.9	
			2C Resources (PJ):	84.9	
	Operator:	Greymouth Petroleum	Permit Expiry:	2036	

Field					Supply Narrative
Ngatoro, Kaimiro, Winsor & Goldie	Location:	Onshore	First Production Year:	1998	The Kaimiro mixing station provides the surface facilities for the Kaimiro, Ngatoro, Winsor and Goldie fields located near Inglewood. Gas production is mid-life with 35 PJ remaining 2P reserves and 28 PJ of 2C resources. Greymouth exploration acreage to the north of the permit could provide upside for the facilities.
	Production Type:	Oil/ Condensate/ Gas	Remaining 2P Reserves (PJ):	34.7	
			2C Resources (PJ):	28.3	
Radnor Surrey	Operator:	Greymouth Petroleum	Radnor		It is unclear where the Radnor and Surrey gas is produced. This study has assumed that this gas is consumed at the field and not exported to the gas pipeline as the fields are largely oil producing.
	Location:	Onshore	Permit Expiry:	2030	
	Production Type:	Oil/ Condensate/ Gas	First Production Year:		
			Remaining 2P Reserves (PJ):	6.5	
			2C Resources (PJ):	0.9	
			Surrey		
			Permit Expiry:	2035	
			First Production Year:	2006	
			Remaining 2P Reserves (PJ):	0	
			2C Resources (PJ):	0	
Turangi	Operator:	Greymouth Petroleum	Permit Expiry:	2036	The Turangi, Ohanga, Onearo and Urenui field produces through the Turangi Mixing station near the Methanex plant at Motunui. The field has the largest remaining reserves of any field and some resources. Production is significant at up to 60 TJ/d. While operator plans are unclear, Greymouth holds exploration acreage to the west of the Pohokura permit that could be prospective and production is expected to continue until 2060.
	Location:	Onshore	First Production Year:	2006	
	Production Type:	Condensate /Gas	Remaining 2P Reserves (PJ):	450	
			2C Resources (PJ):	72.1	
Kowhai	Operator:	Greymouth Petroleum	Permit Expiry:	2032	The Kowhai field produces through the Kowhai Mixing station near the Methanex plant at Motunui. While the field has the limited remaining reserves, 2C resources are similar in size to current reserves + production. Spare production capacity in the surface facilities appears to be significant at up to 30 TJ/d. While operator plans are unclear, Greymouth holds exploration acreage to the west of the Pohokura permit that could be prospective.
	Location:	Onshore	First Production Year:	2009	
	Production Type:	Condensate/ Gas	Remaining 2P Reserves (PJ):	9.3	
			2C Resources (PJ):	66.5	
	Operator:	NZEC	Copper Moki		
	Location:	Onshore	Permit Expiry:	2046	

Field					Supply Narrative
TWN (Copper Moki Waihapa Ngaere Tariki)	Production Type:	Oil/Condensate/ Gas	First Production Year:	2012	The Tariki, Waihapa, Ngaere and Copper Moki (TWN) assets are late life assets with available surface facility capacity. The Tariki structure has remaining 2P reserves of ~14 PJ that could be developed following successful drilling.
			Remaining 2P Reserves (PJ):	0.1	
			2C Resources (PJ):	0	
			Waihapa		
			Permit Expiry:	2036	
			First Production Year:	1990	
			Remaining 2P Reserves (PJ):	2	
			2C Resources (PJ):	0	
			Ngaere		
			Permit Expiry:	2036	
				First Production Year:	
			Remaining 2P Reserves (PJ):	0	
			2C Resources (PJ):	0	
			Tariki		
			Permit Expiry:	2026	
			First Production Year:	1996	
			Remaining 2P Reserves (PJ):	13.8	
			2C Resources (PJ):	0	
McKee	Operator:	Todd Energy	Permit Expiry:	2025	The McKee field is predominantly and oil field with associated gas production. The McKee peaking power station is located near at the site and takes gas from the McKee Mangahewa Production Station (MMPS). Despite the late-life nature of the asset, the field could produce gas for another 10 years from the gas cap.
	Location:	Onshore	First Production Year:	1980	
	Production Type:	Oil/ Gas	Remaining 2P Reserves (PJ):	15.9	
			2C Resources (PJ):	35.8	

Field					Supply Narrative
Mangahewa	Operator:	Todd Energy	Permit Expiry:	2061	The Mangahewa field is a tight gas field adjacent to the McKee field but producing from a separate geologic trend and therefore a gas/condensate field rather than oil-producing. Continued drilling is required to maintain production due to the tight nature of the reservoir. Delays to the current drilling programmed will decrease production in the near term. However considerable reserves and resources remain for the field although the risk profile for this is increasing as the field enters late life and regulatory regime and costs become more onerous.
	Location:	Onshore	First Production Year:	2001	
	Production Type:	Condensate/ Gas	Remaining 2P Reserves (PJ):	224.2	
			2C Resources (PJ):	258.3	
Kapuni	Operator:	Todd Energy	Permit Expiry:	2053	The Kapuni field is a tight gas field in South Taranaki. Continued drilling is required to maintain production due to the tight nature of the reservoir. Kapuni natural gas is high in CO_2 and therefore less economic due to ETS burden. A CCUS scheme would improve the economic and environmental performance of the asset. Regulatory changes enabling CCUS need to happen expeditiously to enable future development and appraisal of the Kapuni field. Considerable reserves and resources are at risk as the field enters late life and regulatory regime and costs become more onerous.
	Location:	Onshore	First Production Year:	1970	
	Production Type:	Condensate/ Gas	Remaining 2P Reserves (PJ):	191.7	
			2C Resources (PJ):	520.3	

Based on these supply outlooks, this study has developed an unconstrained gas supply outlook. This assumes production is not matched to demand and that operators can sell all gas into the market. This outlook is shown in Figure 29 below. The key takeaway from this modelling is that there is potential for a decline in production from the MBIE modelled profiles from 2026 onwards until resources can be brought into production. A plateau period appears possible out until the early 2030s as 2C resources are produced but decline is steep after this point. Due to the lead time in consenting and sanctioning new production it is unlikely that significant amounts of 2C resource can be accelerated to maintain or increase production.

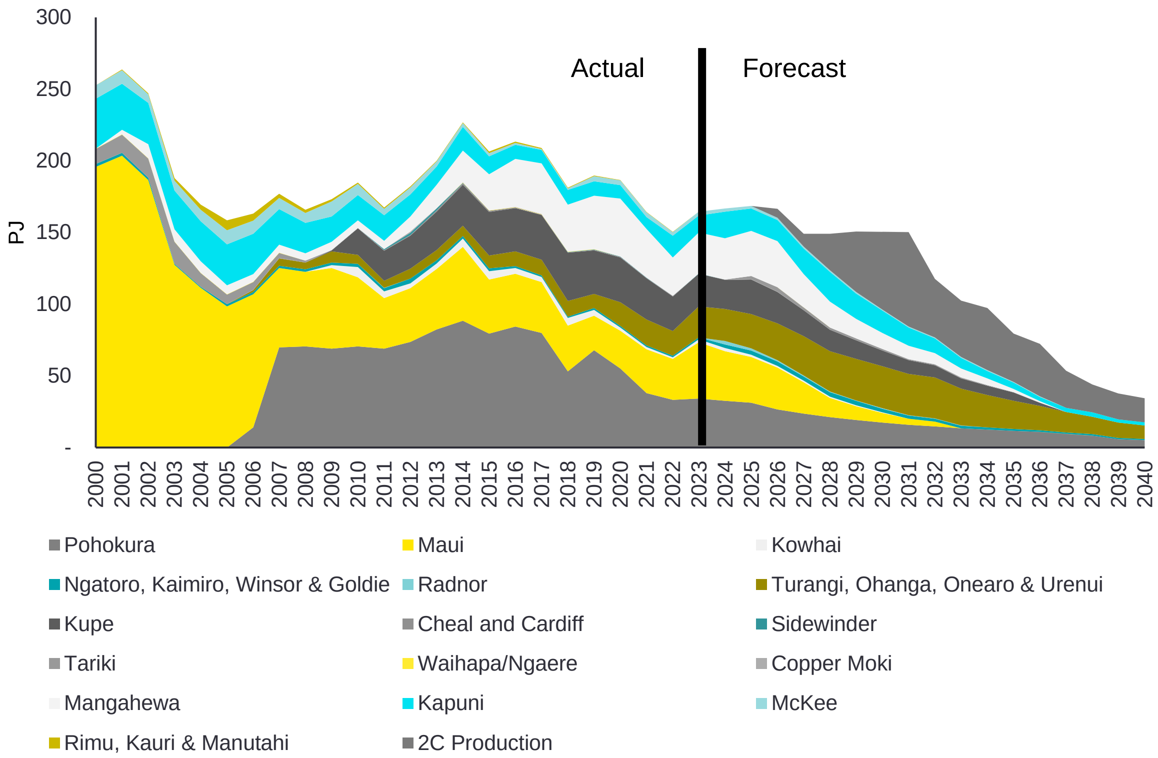

Figure 29: Unconstrained gas supply forecast

It should be noted that this scenario does not represent field operator plans. It is indicative only based on public data and information shared by field operators in confidence. It does not include production from prospective resources which considered in Section 5.4.1.

5.2 Biogas/biomethane supply

Biogas is a mixture of gases produced from the anaerobic digestion of organic matter, such as agricultural waste, manure, plant material, sewage, and municipal waste. Biogas is usually comprised mainly of methane and CO_2, with some trace gases such as hydrogen, hydrogen sulphide, nitrogen and more. Biogas generally comprises around 50% methane.

Biogas is a valuable source of renewable energy. It can be used directly as a fuel source for combined heat and power plants. It can also be upgraded to meet pipeline specification by removing impurities like hydrogen sulphide and CO_2. The output of the upgrading process is termed biomethane and can be used as a direct substitute for natural gas without any changes to end user appliances. The waste material left over after anaerobic digestion is called "digestate" and can be used as an effective fertiliser. Utility scale development of biomethane is well established in many countries, such as Demark, Sweden, Germany and the UK[59]. Production is beginning in NZ with the establishment of the Ecogas project in Reporoa which started production this year and will be

[59] https://task37.ieabioenergy.com/wp-content/uploads/sites/32/2022/02/IEA_T37_CountryReportSummary_2021.pdf

injected into the gas network from Q2 2024[60]. Additionally NZ produces 4.9 PJ/yr of biogas from wastewater treatment plant, industrial biogas and landfill gas operations[61].

The potential for biogas/biomethane in New Zealand was investigated during the development of the Gas Transition Plan Issues paper which was released in August 2023[61]. The overall potential for biogas/biomethane is outlined in Table 30 below. These findings form the basis of the modelling analysis in this report, using different assumptions for biogas development between scenarios as detailed in the modelling assumptions in Appendix A. This study has assumed that only North Island-produced biogas production would be upgraded and connected to the grid and have brought gas into production based on the indicative costs identified in Table 30.

The supply profile only considered production connected to the gas grid and not supply used for heat and power locally. While biogas volumes are not sufficient to replace all current gas supply, development of biogas will be a pathway for residential gas decarbonisation. Supply of gas could be developed locally and mitigate the need for electricity sector investment. As residential consumers could delay or not switch to electrical heat, hot water and cooking equipment through the uptake of biogas, local increases in electricity demand could be moderated. Certification of biomethane would be an important factor to allow the gas to be sold at a premium and recover costs. Green gas certification schemes are discussed in Section 6.4.

Table 30: New Zealand biogas potential and cost of supply

Feedstock	Max. Biogas Potential (PJ/yr)	% Available in North Island	Gas Price ($/GJ)				
			First 40%	40-60%	60-80%	80-90%	Last 10%
Municipal Biosolids	1.6	75%	15	20			
Post-consumer food waste	1.8	75%	30	40	50		
Municipal green waste	1.8*	75%	70	80			
Landfill gas	3	75%	10	15	20	30	
Dairy Wastewater	1.5	70%	20	25	40		
Meat wastewater	0.72	50%	10	25	40		
Pre-consumer food wate	0.26	75%	30	40	50	60	
Supplementary crops	1.5	60%	30	40	50	60	
Animal manure	8.1	25%	35	45	60		
Utility crops	7.5	70%	70	80			

**Including Organics currently going to composting*

***From 5.6% of NZ productive grassland (450,000 ha)*

5.3 Hydrogen supply

Supply of hydrogen has been proposed as a way to decarbonise the natural gas grid. Hydrogen is a clean burning fuel, as water is the only by-product from the combustion process. Green hydrogen made from electrolysis of water could be used on a low carbon basis to replace some gas applications. The limitations on replacing natural gas use with hydrogen, aside from cost, are the difference in calorific value, different safety properties and reactivity of hydrogen with steel. This means that hydrogen is not a direct replacement for natural gas and introduction of hydrogen needs careful consideration. The upper limit for hydrogen concentration prior to appliances needing to be changed is generally set at 20% by volume[62].However, the use of hydrogen is specific to the end use being considered.

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[60] https://www.ecogas.co.nz/news/firstgas-group-and-ecogas-to-turn-biogas-into-renewable-gas-to-inject-into-gas-network

[61] https://www.mbie.govt.nz/dmsdocument/27267-gas-transition-plan-biogas-research-report-february-2023-pdf

[62] https://www.iee.fraunhofer.de/content/dam/iee/energiesystemtechnik/en/documents/Studies-Reports/FINAL_FraunhoferIEE_ShortStudy_H2_Blending_EU_ECF_Jan22.pdf

The potential for hydrogen to be introduced into the gas network was explored in an accompanying report to the recent Gas Transmission Plan Issues Paper[63]. In the scenarios considered in that report blending into the transmission system was not considered feasible due to hydrogen sensitive customers. Blending into distribution networks was considered more feasible as customers were largely residential and commercial with a lower likelihood of specialised equipment and higher willingness to pay.

In this study it is considered that hydrogen blending could occur at the distribution network level to augment gas supply in to residential and commercial consumers in Auckland and Wellington. This would be in addition to local supply of hydrogen to consumers not connected to the gas grid. Hence production of hydrogen in the scenarios only relates to where hydrogen supply interacts with the gas system. Certification of green hydrogen would be an important factor to allow the gas to be sold at a premium and recover costs. Green gas certification schemes are discussed in Section 6.4.

5.4 Prospective/LNG supply

In addition to existing field production and biogas/hydrogen supply, the possibility of further supply being developed has been considered. This would be from two sources:

- Prospective resources
- Liquified natural gas (LNG) imports

Both these sources of supply would be higher cost and they have been assumed to have the same cost for the price outcomes modelling in Section 7.2. These sources of supply are used to balance demand where other sources are insufficient.

5.4.1 Prospective resources

In the modelling of natural gas supply, only reserves and resources currently connected to production stations and able to be injected into the gas pipeline system without further surface facility development have been considered. However, there are potentially additional resources that could be brought into production given further investment in de-risking production and appropriate commercial settings. There are currently 11 active petroleum exploration permits that could yield production[64]. One of these, the Karewa prospect, has associated 2C resources. These permits are summarised in Table 31.

Table 31: Current petroleum exploration permits[64]

Field	Operator	Onshore/ offshore	Permit grant date	Permit expiry date	Remaining Permit Years	2C resources (PJ)
Permit 60403 (225 sqkm in Taranaki Basin)	Greymouth Petroleum	Offshore	1/04/2023	31/03/2035	12	
Mangorei	Greymouth Petroleum	Onshore	1/07/2021	30/06/2031	8	
Puka	Matahio Energy	Onshore	23/09/2008	22/09/2026	3	
Permit 51150 (4 sqkm in Taranaki Basin)	NZEC	Onshore	23/09/2008	22/09/2026	3	
Ridgeline	OMV	Offshore	1/04/2016	31/03/2028	5	
Toutouwai	OMV	Offshore	1/04/2016	31/03/2028	5	
Cloudy Bay	OMV	Offshore	1/04/2015	31/03/2027	4	

[63] https://www.mbie.govt.nz/dmsdocument/27266-new-zealand-hydrogen-scenarios-and-the-future-of-gas-september-2022-pdf
[64] https://data.nzpam.govt.nz/permitwebmaps/?commodity=petroleum

Field	Operator	Onshore/ offshore	Permit grant date	Permit expiry date	Remaining Permit Years	2C resources (PJ)
Permit 60742 (53 sqkm in Taranaki basin)	Riverside Energy	Onshore	1/07/2021	30/06/2031	8	
Karewa	Todd Energy	Offshore	1/04/1993	31/07/2023	0	155
Tuihu	Todd Energy	Onshore	1/04/2017	31/03/2027	4	
Tarata	Todd Energy	Onshore	3/04/2020	2/04/2030	7	

Given the likely incoming government's policy on reversal of the offshore exploration ban[65], there is potential for further permits to be issued. However, supply from these fields Is potentially costly and development timeframes lengthy. Prospective supply has therefore been modelled alongside LNG import in terms of timeframes and cost as both these supply sources would have similar economic issues.

5.4.2 LNG imports

Liquified natural gas (LNG) is natural gas which has been cooled to temperatures of -162 °C to allow it to be transported efficiently over long distances. As it reduces the volume of the natural gas by approximately 600 times, allowing for more efficient transport. LNG cannot be directly substituted for natural gas in its liquid state. However, LNG can be re-gasified and injected into gas networks for use interchangeably with pipeline gas. Cargoes of LNG are typically around 4 PJ.

While LNG was first produced in the 1940s, international trade in LNG dates back to 1959. Initial projects were sanctioned based on securing long-term offtake contracts but increasing there is a spot market for LNG cargoes and international trade has become increasing liquid. Gas pricing is generally set either referenced to oil costs in Asian markets or the Henry Hub US gas price. This allows gas producers to potentially access higher pricing than local markets – as observed by Australian gas markets as east coast LNG facilities came onstream[66]. LNG pricing is significantly higher than NZ domestic gas pricing and is discussed further in Section 7.2.

LNG facilities have also become increasingly flexible over the last two decades. Technology improvements have reduced the variable size of LNG liquefaction facilities and increased storage options. Whereas previously re-gas facilities were large scale onshore technologies, it is now feasibility to charter Floating Re-gasification Storage Unit vessels (FSRUs) and Floating Storage Units (FSUs). This allows facilities to be moored at site for a given time period and potentially redeployed at the end of project life. While port modifications may be required and mobilisation/demobilisation vessel costs are not trivial, this mode of development has gained traction as port land is not required for onshore re-gasification facilities.

65 https://www.rnz.co.nz/news/political/503329/green-party-launches-petition-to-keep-ban-on-offshore-oil-and-gas-exploration
66 https://www.rba.gov.au/publications/bulletin/2021/mar/understanding-the-east-coast-gas-market.html

Work was commission on potential import options for LNG as part of the Gas Transition Plan issues paper[67]. This work identified four options for terminal location. The purpose of this report is not to select a location for LNG import facilities but note that the following characteristics were common to all options:

- Modifications to existing port facilities or construction of new port facilities could be required
- Access to significant transmission network capacity is required to allow cargoes to be offloaded in a timely manner
- Gas storage would be required – either in underground storage or using an FSU to allow for gas to be available when required
- Lead times of 6-8 weeks are required for cargo procurement
- A complex commercial chain would be required to underwrite offtake and support project economics

The modelling has therefore used LNG in certain scenarios to represent the supply gap where domestic gas of biogas, hydrogen and natural gas is insufficient to meet demand. It has been used as balancing factor and imported to match demand. The implications of this are reflected in the price modelling in Section 7.2.

5.5 Supply Modelling outputs

5.5.1 Total gas supply

The following charts show the forecast gas supply by source between 2023 and 2050 under each scenario.

Industry focus

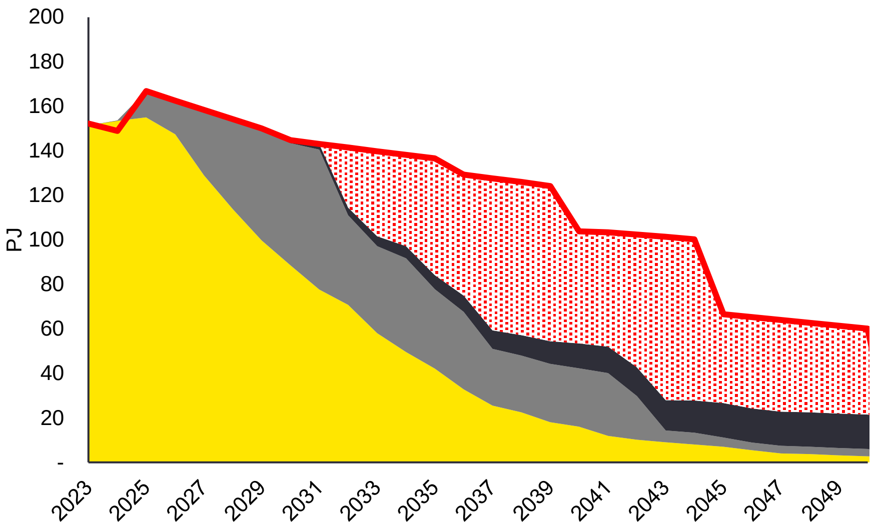

Figure 30: Annual supply by source – Industry focus scenario

[67] https://www.mbie.govt.nz/dmsdocument/27262-lng-import-and-options-to-increase-indigenous-gas-market-capacity-and-flexibility-in-new-zealand-march-2023-pdf

In the *Industry focus* scenario shown in Figure 30 above, 2P production is able to support baseload electricity and average year gas demand until 2025. However dry year electricity demand is at risk. Development of 2C resources will need to commence from 2025 to provide baseload electricity demand. As average year gas demand reduces, dry year cover increases prior to Prospective/LNG supply being required to cover dry year demand from 2032 onwards. Combined 2P and 2C supply and biogas supply drops below average year demand from 2031 and Prospective/LNG supply would be required to fulfil average year demand thereafter. Biogas supply grows to 6 PJ by 2035 and hydrogen supply is not directed to the gas network in this scenario. A summary of gas supply is given in Table 32.

Table 32: Summary of gas supply by source – Industry focus scenario (PJ)

	2023	2025	2030	2035
2P supply	151.4	155.0	88.6	42.2
2C supply	-	11.5	54.8	35.6
Biogas	-	0.1	1.3	6.4
Hydrogen	-	-	-	-
Prospective/LNG supply	-	-	-	52.4
Total	151.4	166.7	144.7	136.6

Methanex exits early

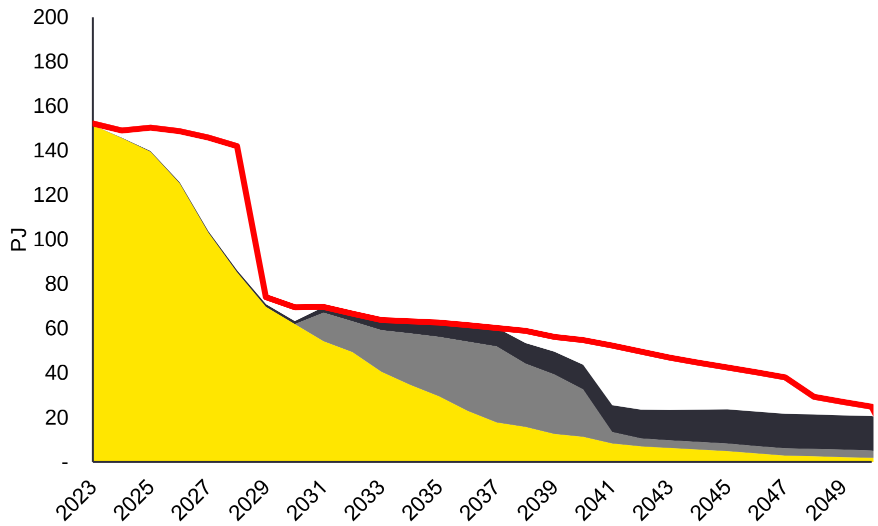

Figure 31: Annual supply by source - Methanex exits early scenario

As Methanex's exit is assumed to be signalled well in advance, there is low investment in maintaining 2P production and/or developing 2C resources in the short term as operators are uncertain of offtake. As a result, average year demand is at risk until Methanex exits in 2029. The supply profile is shown in Figure 31 above. Following this exit, 2C resources are able to be developed to match dry year demand from 2031. Prospective/LNG supply is not developed, and supply of gas drops below average year demand in 2038. Biogas supply grows to 6 PJ by 2035 and hydrogen supply is not directed to the gas network in this scenario. A summary of gas supply is given in Table 33.

Table 33: Summary of gas supply by source – Methanex exits early scenario (PJ)

	2023	2025	2030	2035
2P supply	151.4	139.5	62.0	29.5
2C supply	-	-	-	26.9
Biogas	-	0.3	1.3	6.4
Hydrogen	-	-	-	-
Prospective/LNG supply	-	-	-	-
Total	**151.4**	**139.7**	**63.3**	**62.8**

Elevate electricity

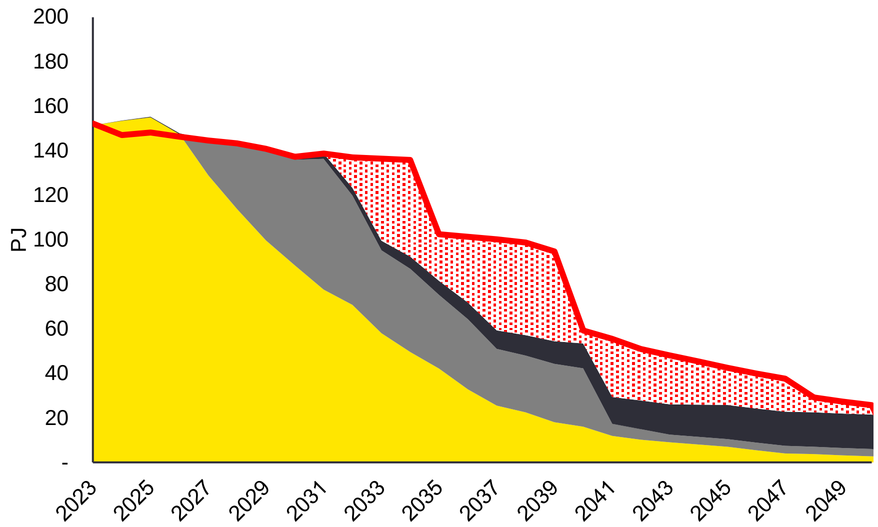

Figure 32: Annual supply by source – Elevate electricity scenario

As the *Elevate electricity* scenario directs gas towards electricity generation, demand from other sectors is moderated and 2P supply is able to largely meet demand until 2027. This is demonstrated in the supply profile shown in Figure 32. Conversion of 2C resources is able to meet demand until 2031 when development of Prospective/LNG supply is required to meet demand. Biogas supply grows to 6 PJ by 2035 and hydrogen supply is not directed to the gas network in this scenario. A summary of gas supply is given in Table 34.

Table 34: Summary of gas supply by source – Elevate electricity scenario (PJ)

	2023	2025	2030	2035
2P supply	151.4	155.0	88.6	42.2
2C supply	-	-	47.4	33.0
Biogas	-	0.3	1.3	6.4
Hydrogen	-	-	-	-
Prospective/LNG supply	-	-	-	20.9
Total	**151.4**	**155.2**	**137.3**	**102.5**

Supply headwinds

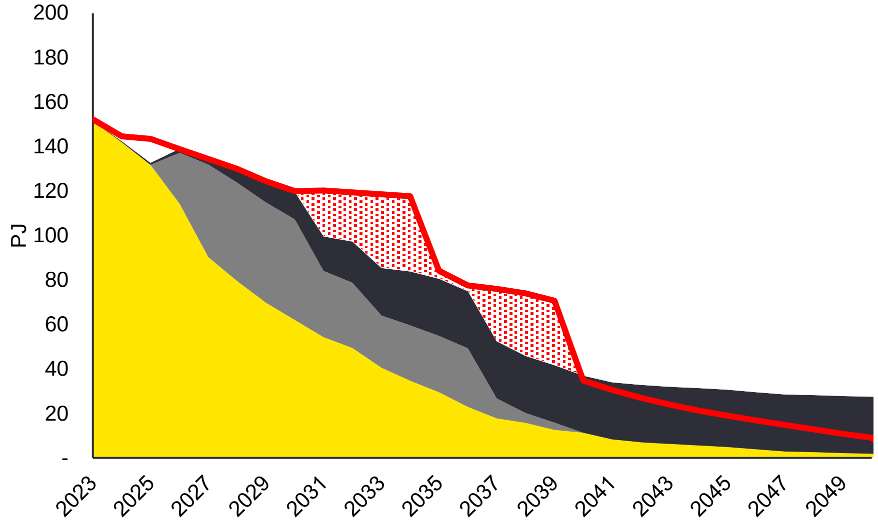

Figure 33: Annual supply by source (supply headwinds) scenario

Due to reduced field deliverability In the *Supply headwinds* scenario, 2C resources are not available to fill in and meet dry year demand – as shown in Figure 33. Supply dips below baseload electricity demand in 2025 as 2C resources are not able to ramp up quickly. Prospective/LNG supply fills dry year demand following 2031. Biogas supply ramps up earlier and increases to 25 PJ by 2035, sufficiently meeting the reduced annual demand from 2040 onwards alongside the 2P supply. Some minor blending of hydrogen in distribution networks is allowed for but this does not materially change gas the supply and demand balance. However the long term effect is that demand is eroded and there is potentially unmet demand in the market. A summary of gas supply is given in Table 35.

Table 35: Summary of gas supply by source – Supply headwinds scenario (PJ)

	2023	2025	2030	2035
2P supply	151.4	131.7	62.0	29.5
2C supply	-	-	45.2	25.4
Biogas	-	0.9	12.4	25.7
Hydrogen	-	-	0.4	0.4
Prospective/LNG supply	-	-	-	3.3
Total	**151.4**	**132.6**	**120.0**	**84.2**

5.5.2 Natural gas supply

The 2P production profile for natural gas supply is based on the production profiles reported in the MBIE reserves reporting exercise. In the *Industry focus* and *Elevate electricity* scenarios, these scenarios are modelled as per the reporting. However, in the *Methanex exits early* scenario it is assumed that lower demand certainty reduces the appetite for investment in maintaining 2P production and therefore production is reduced. In the *Supply headwinds* scenario there is a supply shock and deliverability of 2P reserves is reduced. This is shown in Figure 34 below. A summary of 2P supply is given in Table 36.

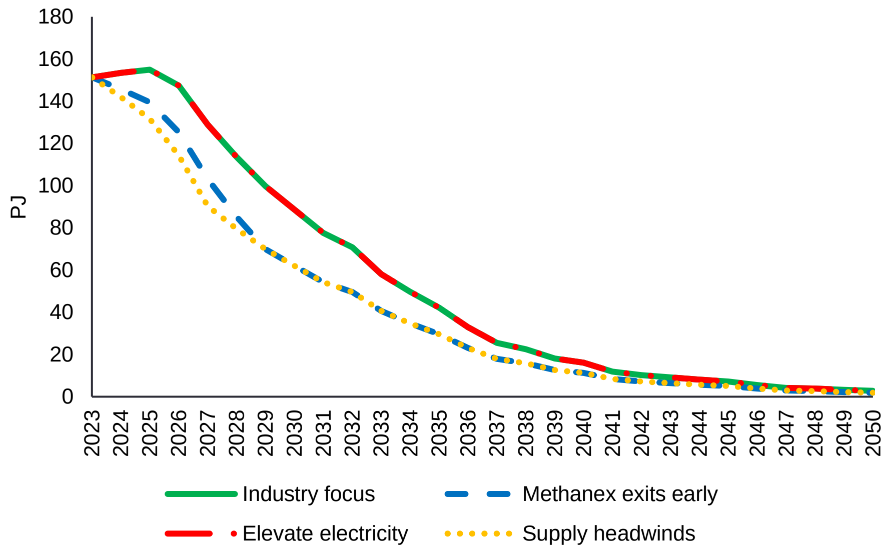

Figure 34: 2P production by scenario

Table 36: Summary of 2P gas production by scenario (PJ)

	2023	2025	2030	2035
Industry focus	151.4	155.0	88.6	42.2
Methanex exits early	151.4	139.5	62.0	29.5
Elevate electricity	151.4	155.0	88.6	42.2
Supply headwinds	151.4	131.7	62.0	29.5

Gas 2C resources are developed in all scenarios to meet market demand. The *Industry focus* scenario is assumed to have the largest amount of 2C resources converted to production and these are assumed to be developed to backfill demand from Methanex and the electricity sector. The certainty of offtake provided by Methanex is assumed to support investment in development. Lower demand accompanies the lower supply in the *Supply headwinds* scenario but supply is accelerated to serve inflexible demand in the short term until alternatives can be found. In the Elevated electricity scenario 2C supply is assumed to commence in 2027 to meet electricity sector demand. Finally, in the *Methanex exits early* scenario 2C supply is assumed not to be developed until after the exit of Methanex as there is insufficient certainty of demand to support investment in additional production. The comparison of these scenarios is shown in Figure 35. A summary of 2C supply is given in Table 37.

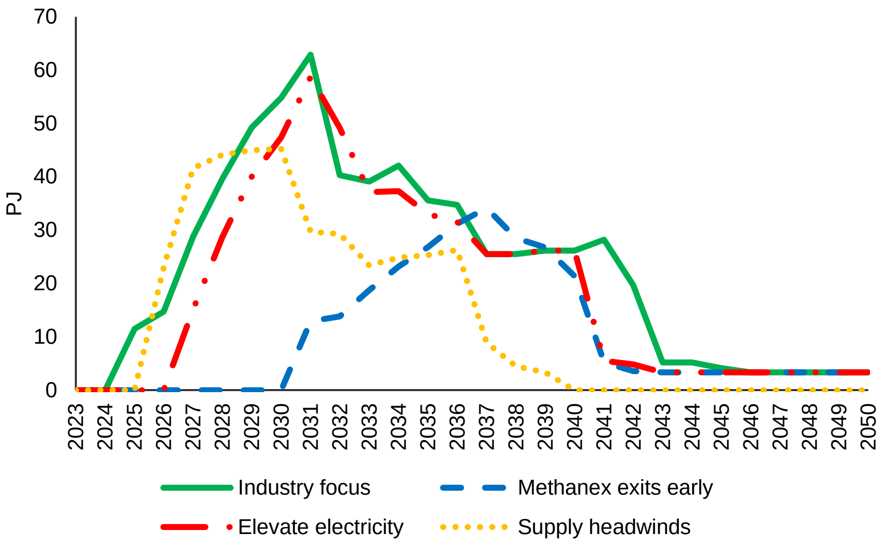

Figure 35: 2C Production supply by scenario

Table 37: Summary of 2C gas production by scenario (PJ)

	2023	2025	2030	2035
Industry focus	-	11.5	54.9	35.6
Methanex exits early	-	-	-	26.9
Elevate electricity	-	-	47.4	33.0
Supply headwinds	-	-	45.2	25.4

5.5.3 Biogas/biomethane supply

Biogas supply to the gas grid is a nascent industry and therefore it has been modelled as having significant lead times for grid connection. For most scenarios this study has modelled uptake of established, producing biogas up to 2030 with build out of up to 30% of supply potential over the next 2 decades. However, in the *Supply headwinds* scenario, this study has modelled accelerated uptake of biogas in the face of interruptions to natural gas supply with up to 50% of biogas potential being developed by 2035. The resulting supply profiles are shown in Figure 36. A summary of biogas supply is given in Table 38.

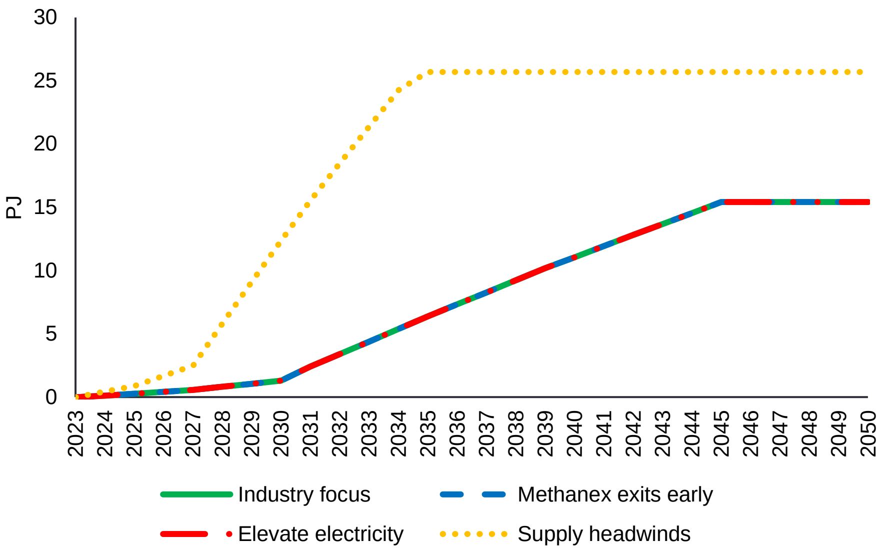

Figure 36: Biogas supply by scenario

Table 38: Summary of biogas supply by scenario (PJ)

	2023	2025	2030	2035
Industry focus	0	0.3	1.3	6.4
Methanex exits early	0	0.1	1.3	6.4
Elevate electricity	0	0.1	1.3	6.4
Supply headwinds	0	0.9	12.4	25.7

5.5.4 Hydrogen supply

Blending of hydrogen in the gas pipeline has not been considered in the scenarios due to the high cost and complexity of integrating supply. However, this study has considered hydrogen blending in the *Supply headwinds* scenario, as a response to meet residential/commercial gas demand in Auckland and Wellington. This would be blended at the distribution network and therefore would have a modest contribution to gas supply as shown in Figure 37 below. The contribution would decline with overall natural gas demand from these sectors. A summary of hydrogen supply is given in Table 39.

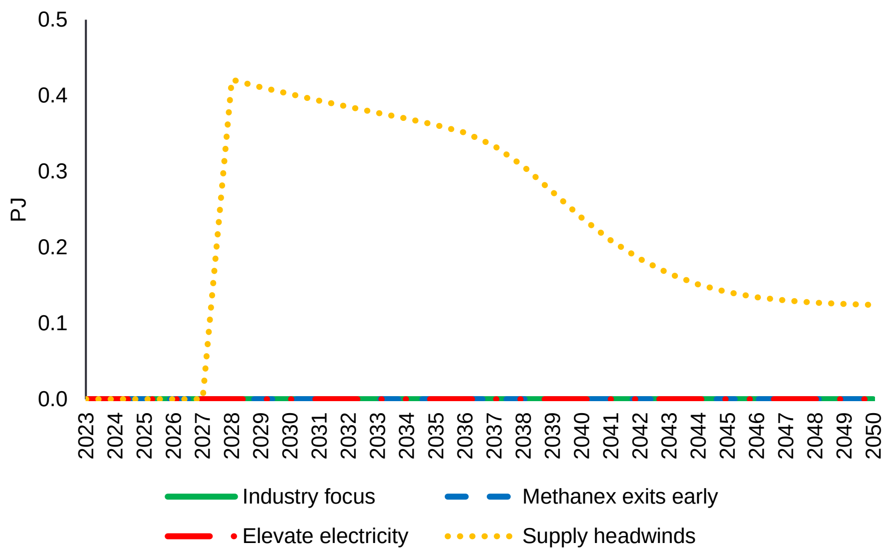

Figure 37: Hydrogen supply by scenario

Table 39: Summary of hydrogen supply by scenario (PJ)

	2023	2025	2030	2035
Industry focus	-	-	-	-
Methanex exits early	-	-	-	-
Elevate electricity	-	-	-	-
Supply headwinds	-	-	0.4	0.4

5.5.5 Prospective/LNG supply

The modelling considers that 2030 would be the earliest feasible start date for Prospective/LNG supply due to the lead time to build terminal infrastructure or convert prospective resources. These timeframes are very ambitious. The *Methanex exits early* scenario does not consider Prospective/LNG supply as in this scenario demand is too uncertain not incentivise investment in additional supply. In the Elevate electricity scenario Prospective/LNG supply commences in 2032 and builds to a maximum of 44 PJ in 2034 but reduces thereafter as overall demand reduces. In the *Industry focus* scenario, supply also commences in 2032 to support demand in other sectors as indigenous supply is used by industry. Investment in Prospective/LNG supply is required to provide supply from 2031 in the *Supply headwinds* scenario due to the need to quickly replace other gas supply. However, demand is lower due to demand erosion caused by the constrained gas supply. The supply profiles for each scenario are shown in Figure 38. The LNG supply is summarised in Table 40.

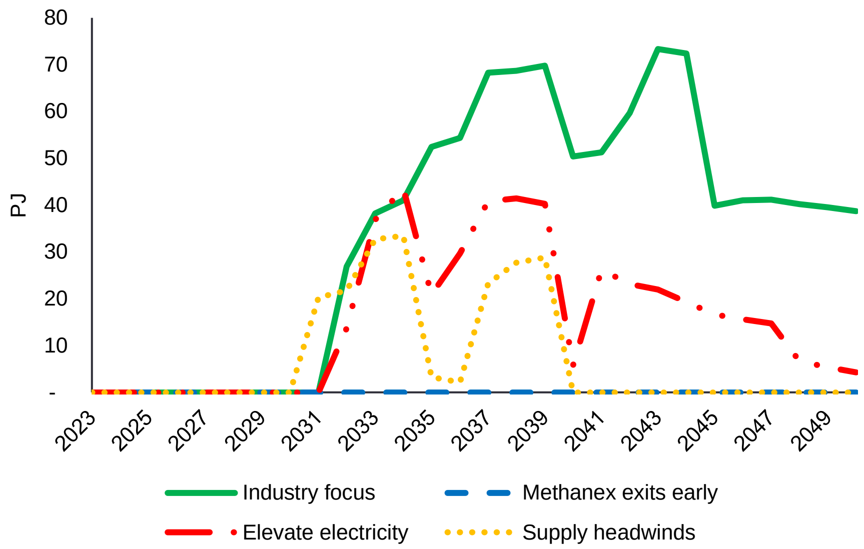

Figure 38: Prospective/LNG supply by scenario

Table 40: Summary of Prospective/LNG supply by scenario (PJ)

	2023	2025	2030	2035
Industry focus	-	-	-	52.4
Methanex exits early	-	-	-	-
Elevate electricity	-	-	-	20.9
Supply headwinds	-	-	-	3.3

While this supply could be from domestic gas, this study has modelled the number of cargoes per year that would be required to provide this supply. The notional number of LNG cargoes per year in each scenario is shown in Figure 39. The notional number of cargoes per year is summarised in Table 41.

In all these scenarios it is assumed that Methanex contracted supply is not re-sold into the market in preference to development of Prospective/LNG supply. While it is feasible that Methanex could re-sell their supply to the market, this study has modelled the supply gap in order to understand the magnitude of gas supply required in each scenario and the impact on prices of higher cost supply.

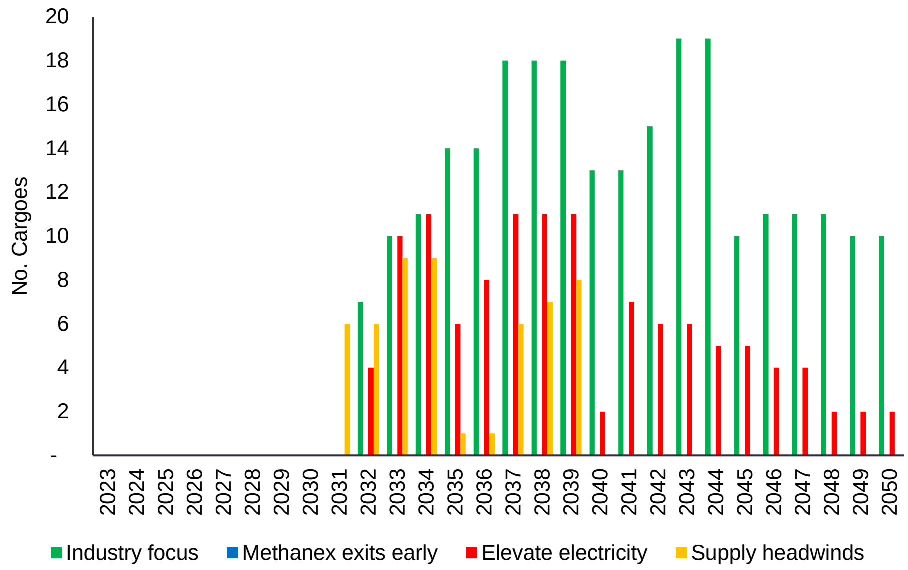

Figure 39: Notional LNG cargoes by scenario

Table 41: Summary of notional LNG cargoes per year by scenario (No. cargoes)

	2023	2025	2030	2035
Industry focus	-	-	-	14
Methanex exits early	-	-	-	-
Elevate electricity	-	-	-	6
Supply headwinds	-	-	-	1

6. Scenario enablers

There is much more to the gas industry than the straight-forward balancing of supply and demand. This section outlines some of the key enablers that will impact the gas industry's future and determine the role it plays in New Zealand's energy transition and economy. With the right settings, these enablers present opportunities to accelerate the transition and improve the economy. The enablers are not explicitly modelled within the analysis, and it is beyond the scope of this study to assert how these issues should or should not be handled. Rather they set the context for this study and are understood to be levers that may be pulled to achieve certain outcomes. The different enablers can be grouped into two categories:

- The first three enablers: gas networks, gas storage and CCUS constitute **infrastructure or technologies** that support the gas industry and react to different supply and demand contexts.

- The last two enablers: renewable gas certification and the ETS are **policy/economic instruments** that set the scene for the sector and drive behaviour.

The structure of each sub-section consists of a description of the enabler, the policy context and either the implications for the infrastructure/technology or implications of the policy/economic instrument.

6.1 Gas networks

The natural gas supply network is located in the North Island. The pipelines are classified into transmission pipelines and distribution networks. Natural gas supply is currently injected into the transmission system in Taranaki. The system configuration is therefore designed to efficiently move gas from Taranaki to end users in other parts of the island.

While the system has been designed for natural gas, it is possible to use this infrastructure for renewable sources of gas. For example, biogas can be upgraded to biomethane to meet pipeline specifications and therefore directly substitute natural gas. Additional flexibility on the specification could relax the standard on oxygen content which could reduce treatment costs without compromising safety. Hydrogen has some challenges with pipeline material compatibility, particularly in the transmission network, but is technically capable of being blended up to 20% by volume in the distribution networks, although this would require modifications to the specification to allow this[68].

Gas pipelines are regulated under Part 4 of the Commerce Act 1986 as monopoly infrastructure. This means that the revenue able to be earned by gas pipeline owners is regulated by the Commerce Commission through a price-quality path and information disclosure regime[69]. Given this regime, a key concern of gas stakeholders is that, with potentially declining throughput of gas as New Zealand transitions, pricing on a per unit basis could rise to allow for return of capital, return on capital and cover operating costs.

Further to this, gas pipeline operators are concerned that investments made in the system will not be recovered and they may be left with stranded assets. For this reason, the Commerce Commission undertook steps in their 2022 reset to provide increased flexibility of pricing/revenue to increase responsiveness to changes in the quantity of gas being supplied, the types of gas being injected into the system and the duration of network use. However, further measures may be required as the sources, volume, and role of gas change into the future.

The gas supply and demand scenarios this study has investigated are likely to have significant impacts on gas networks due to changes in the quantity and location of gas demand and the types

[68] https://www.standards.govt.nz/shop/nzs-54422008/ Work to modify the standard is already underway. An interim standard to allow blending of biomethane is nearly complete. Focus is due to shift in 2024 to allow hydrogen blending.
[69] https://comcom.govt.nz/regulated-industries/gas-pipelines/our-role-in-gas-pipelines

of gas being supplied. The key challenges that can be identified with reduced supply or different inputs are summarised in Table 42.

Table 42: Key gas network implications from changes to the quantity and nature of gas supply

System change	Challenges
Overall reduced gas supply	▸ Will require increased focus on system flexibility to maintain resilience of supply with a lower supply base ▸ Tariffs could increase due to lower throughput affecting affordability ▸ Assets could be stranded due to shortened asset lives or curtailment of gas supply at particular locations
Natural gas supply	▸ Reduction in natural gas supply could trigger input of other sources of supply to maintain throughput ▸ Introduction of other supply could trigger changes to gas specification or network configuration
Biogas	▸ May require relaxation of the gas specification to improve economics ▸ Requires investment in injection infrastructure ▸ Could require investment in reconfiguration of pipelines to accommodate changes in injection locations as biogas does not need to be produced in Taranaki ▸ Biogas could be injected into the distribution network which would require commercial changes if users were not connected to the same network
Hydrogen	▸ Will require a change to the gas specification to allow injection ▸ May not be compatible with high strength steel pipelines but more likely to be compatible with HDPE pipelines ▸ Requires investment in injection infrastructure ▸ Could require investment in reconfiguration of pipelines to accommodate changes in injection locations as hydrogen does not need to be produced in Taranaki ▸ Hydrogen could be injected into the distribution network which would require commercial changes if users were not connected to the same network
LNG	▸ Would support gas throughput and mitigate potential pipeline tariff increases due to reduced throughput. ▸ Will not require a change to the gas specification to allow injection as this is pipeline specification once regasified ▸ Could require investment in new or reconfigured pipeline to accommodate flows and dependent on import locations
Users	▸ Large users transitioning away from gas could lead to some parts of the network becoming redundant and / or drive reconfiguration requirements ▸ If Government policy or gas prices reduce demand for new connections, and/or reduction of existing connections, in the distribution network could drive reconfiguration requirements ▸ Users and appliances would need be comfortable / compatible with other / mixed gas sources (e.g. hydrogen blending)

6.2 Gas storage

Underground gas storage can be developed to increase the flexibility of gas supply systems. As gas fields are natural systems it is often preferable to produce at a steady rate. This ensures that wells are managed to avoid damage to the reservoir. However, gas demand varies over daily, seasonal, and annual timeframes:

- Daily – home heating/cooking, electricity demand, industrial commercial demand.
- Seasonal – winter heating demand, seasonal industrial activities (e.g. dairy processing), winter power demand.
- Annual – dry year electricity demand

Variations in demand over the day can be managed through gas network storage (known as *linepack*). However longer-term storage needs require a greater amount of gas to be stored and underground gas storage is well suited to managing this variability. Users can also look to store gas at times of low prices and sell either into the market at high gas price times or high electricity price times. Studies on LNG and system flexibility undertaken to support the Gas Transition Plan Issues Paper identified that underground gas storage was more cost effective than above ground storage, such as LNG or compressed gas[70].

Underground storage facilities at the Ahuroa reservoir were established by Origin Energy in 2008 after gas production at the field was complete. This field is adjacent to the Taranaki Combined Cycle and Stratford Peaker power stations and therefore Ahuroa was developed as an integrated operation with the electricity generation. The reservoir was initially understood to be capable of storing 18 PJ of gas with cushion gas of 6PJ required to support production.

In 2018 Contact Energy (the successor to Origin) sold the gas storage facility to Firstgas Group who have operated the field as a merchant gas storage facility. Nova Energy and Contact hold contracts with Firstgas that allow for certain rates of injection and withdrawal from the facility and certain storage capacities within the reservoir[70]. In December 2022 it was revealed that storage capacity had reduced to between 10 and 12 PJ and 4 more PJ had been converted to cushion gas – bringing the working storage volume to somewhere between 6 and 8 PJ. Cushion gas will be recovered (at a low rate) at the end of facility life but cannot be called upon prior to end of facility life[71].

Gas storage is not regulated under the Commerce Act 1986. Stored gas in Ahuroa remains the property of the storage users who pay a fixed annual Capacity Reservation Fee (CRF) to Firstgas to use the facility. Fees to Firstgas are in addition to the carrying cost of holding the gas in the reservoir which is a cost to users.

Additional storage options have been discussed as being desirable to maintaining flexibility in the gas system. Genesis Energy had expressed a desire for a further 110 TJ/d of gas flexibility and 20 PJ of storage in 2020[72]. Additional options for underground storage have been identified as follows:

- Tariki field – up to 20 PJ of storage and 75 TJ/d of injection/withdrawal capacity[70].
- Pohokura/Maui – storage integrated with ongoing production. However, the subsurface characteristics of both these fields are not well suited to storage[70].
- Rimu, Kauri, Manutahi – has been discussed as a further gas storage location

Development of storage at the Tariki fields has been assessed as between $62m and $92m with a development timeframe of 2-3 years[70]. The key issue for the development of storage will be confidence by the owners that the storage will be used for a sufficient number of years to recover the development costs from users.

Biomethane and LNG would be able to be stored in current and future natural gas storage facilities as they are chemically equivalent to natural gas. However, LNG import could include some storage either in a floating LNG storage and regasification unit (FSRU) or in a dedicated floating storage unit (FSU). Underground storage of hydrogen is currently undertaken in salt caverns, which are not a feature of New Zealand's geology. Work is being undertaken by the University of Canterbury to understand the potential for storage of green hydrogen in Taranaki. This research programme is due to complete in 2027[73].

70 https://www.mbie.govt.nz/dmsdocument/27262-lng-import-and-options-to-increase-indigenous-gas-market-capacity-and-flexibility-in-new-zealand-march-2023-pdf
71 https://contact.co.nz/-/media/contact/mediacentre/2022/ahuroa-gas-storage-announcement.ashx?la=en
72 https://media.genesisenergy.co.nz/genesis/investor/legacy-reports-and-presentations/genesis-energy-stakeholder-day-presentation-(strategy-session).pdf
73 https://www.mbie.govt.nz/science-and-technology/science-and-innovation/funding-information-and-opportunities/investment-funds/endeavour-fund/success-stories/past-rounds/success-stories-2022/

The gas supply and demand scenarios, that this report has investigated, could have significant impacts on gas storage due to changes in the make-up of gas users and the types of gas being supplied. The key challenges that can be identified with reduced supply or different inputs are summarised in Table 43.

Table 43: Key gas storage implications from changes to the quantity and nature of gas supply

System change	Implications
Overall reduced gas supply	▸ Storage could become more important as supply will be less able to be ramped up and down. ▸ Gas storage facilities may become more costly on a per unit basis if there is less frequent cycling of gas due to lower supply
Natural gas supply	▸ Storage could become more important as supply will be less able to be ramped up and down. ▸ Gas storage facilities may become more costly on a per unit basis if there is less frequent cycling of gas due to lower supply
Biogas	▸ No impact on natural gas storage facilities as biomethane will be able to be stored in natural gas storage facilities ▸ Location of storage may need to change if biogas is not produced in Taranaki or gas is connected to distribution systems only
Hydrogen	▸ May not be able to be stored in existing gas storage facilities or oil and gas reservoirs ▸ Could require a regulatory regime if stored outside existing oil and gas reservoirs
LNG	▸ Could increase the need for storage as cargoes will need to be stored prior to use if the development option does not have storage integrated

6.3 Carbon Capture, Utilisation, and Storage

Carbon Capture, Utilisation, and Storage (CCUS) technologies can capture CO_2 from either specific emission sources or directly from the air. The captured CO_2 is then used or securely stored. An overview of CCUS is given in Figure 40.

CCUS technologies have been in use since 1972, with enhanced oil recovery being used at the Terell Natural Gas Processing Plant. Carbon capture technologies are not new and are often installed in upstream production facilities to remove CO_2 from gas in order to meet pipeline specification. Tax credits in the US for carbon capture have been the main driver for uptake as these allowed a revenue stream to be realised for the CCUS activity[74]. Activity has increased as emissions trading (and other climate change related) schemes emerged that supported the economics of CCUS. In 2022, the global CO_2 capture capacity increased by 44% from the previous year, hitting 244 million tonnes annually[75]. CCUS can play a key part in reducing both upstream and downstream emissions. Upstream carbon emissions can be captured at the point of natural gas extraction (this is particularly relevant for fields that have a high CO_2 content) or downstream during the combustion of natural gas in power plants.

Storage of CO_2 is a well-established technology which is built upon upstream oil and gas practices developed over the last century. At a global scale, there is very large potential to store CO_2 underground permanently in reservoirs and aquifers, for example through mineralisation[76]. The focus on technology development is therefore primarily on capture.

As CO_2 concentrations vary by site and removal technologies are specific to the source of CO_2, the cost of CO_2 capture varies significantly. Most technologies target existing uses of fossil fuels and reduce their carbon intensity. However, there is potential to have negative emissions technology

[74] https://www.iea.org/policies/4986-section-45q-credit-for-carbon-oxide-sequestration
[75] https://status22.globalccsinstitute.com/wp-content/uploads/2023/03/GCCSI_Global-Report-2022_PDF_FINAL-01-03-23.pdf
[76] https://www.araake.co.nz/assets/Uploads/Ara-Ake-Report-Carbon-Dioxide-Removal-and-Usage-in-Aotearoa-New-Zealand.pdf

through the use of post-combustion CCUS where bioenergy is being burned – Bioenergy Carbon Capture and Storage (BECCS).

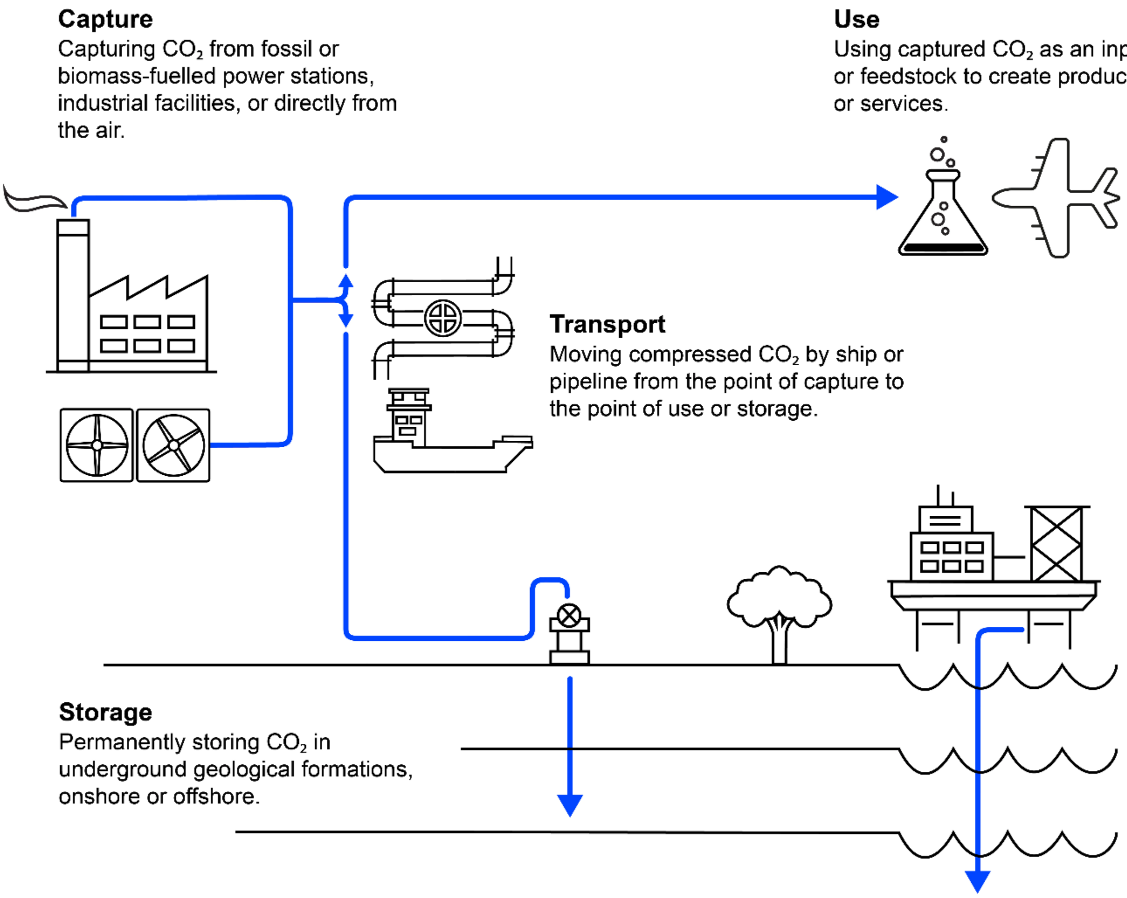

Figure 40: CCUS overview[77]

New Zealand has been a slow mover in adopting CCUS technology but has made progress in recent years. This progress has been focused on the geothermal power industry[78].

Assessment of the CCUS potential in New Zealand completed for the Gas Transition plan found promising potential for sequestration at the Maui East and Kapuni gas fields. Work by Ara Ake[79] also identified potential for the utilisation of CO_2. Currently CO_2 from the Kapuni field is separated and used in industry. CO_2 is also valuable for the production of Methanol, urea and synthetic fuels (when combined with green hydrogen).

[77] https://www.iea.org/reports/about-ccus
[78] https://www.energynews.co.nz/news/annual-report/141222/CO2-reinjection-boosts-ngawha-valuation
[79] https://www.araake.co.nz/assets/Uploads/Ara-Ake-Report-Carbon-Dioxide-Removal-and-Usage-in-Aotearoa-New-Zealand.pdf

The current regulatory environment does not provide strong support for CCUS as an activity. NZUs can be generated by carbon removal activities, such as forestry and CCUS as per Schedule 4 of the Climate Change Response Act 2002[80]. Regulations governing the generation of units through forestry are established but regulations for the generation of units through CCUS have not been developed. Hence CCUS activities relating to post-combustion capture or DAC are not incentivised as operators are not able to generate a revenue stream. However, for gas producers, CCUS reduces their reported emissions and therefore their NZU obligation. So, gas producers are incentivised as they can generate revenue from CCUS.

However, assessments of NZ's legal framework have found that it would be difficult to permit and regulate CCUS activities[81]. This is due to the following issues:

- Onshore, the storage of carbon underground would be considered a discharge under the Resource management Act 1991 and would need to be covered by an appropriate policy statement
- Offshore, the storage of carbon in reservoirs could be considered marine dumping
- There is no regime for continued liability for storage of carbon or consideration of how any potential leakage from the reservoir would be accounted for in the ETS
- There is no regime for property rights to the subsurface outside the Crown Minerals Act 1991 which is designed for oil and gas extraction
- There is no way to manage competing uses of the subsurface
- Infrastructure for the transport of CO_2 would not be considered utility infrastructure as it not transmitting gas

The gas supply and demand scenarios this study has investigated will have significant impacts on CCUS uptake due to changes in the quantity and location of gas demand and the types of gas being supplied. The key implications that can be identified with reduced supply or different inputs can be summarised in Table 44.

Table 44: Key CCUS implications from changes to the quantity and nature of gas supply

System change	Challenges
Overall reduced gas supply	▸ Reduction in gas supply would reduce available carbon for CCUS and therefore decrease the duration and attractiveness of CCUS projects
Natural gas supply	▸ Reduction in CO_2 supply from gas fields due to decreased production ▸ Wind down of production would decrease attractiveness of CCUS projects
Biogas	▸ Could incentivise negative emissions BECCS if this biogas supply can be directed to a large user – either through the gas network or commercially through gas certification
Hydrogen	▸ Unlikely to impact CCUS uptake if green hydrogen is used.
LNG	▸ Would support uptake of post-consumer CCUS

80 https://www.legislation.govt.nz/act/public/2002/0040/latest/DLM1662864.html
81 https://www.mbie.govt.nz/dmsdocument/27265-carbon-capture-and-storage-taking-action-under-the-present-law-pdf

6.4 Renewable certification schemes

Renewable certification schemes are programmes or systems that provide verification and assurance of the renewable nature of energy sources. Certification allows producers of renewable energy (which can often be more costly) to justify a premium price for their product. This also allows purchasers to verify reductions in their energy emissions intensity for their own greenhouse gas accounting. Certificates can also be separable and traded without trade of the underlying commodity.

Certification schemes can be backed by governments to encourage development of renewable energy. An example of this is the Large-Scale Generation Certificate Scheme (LGCs) in Australia. Under this scheme energy buyers have an obligation to purchase LGCs that are created through the generation of electricity in eligible renewable generation schemes. The scheme encourages development of new renewable generation by creating an obligation and market for the LGCs[82]. As the scheme set a baseline of renewable generation at the beginning of the scheme, LGCs comply with the principle of additionality which is inherent in most renewable certification schemes – i.e. the certificate must contribute to adding to the supply of renewable energy.

Similar schemes are available and under development for gas and hydrogen in Europe and the UK. Some examples are:

- The TÜV SÜD CMS 70 standard, known as "GreenHydrogen" certifies the production of green hydrogen produced from renewable energy sources[83].
- GreenGas is a guarantee of origin scheme for green gases including hydrogen, biomethane and biopropane in the UK[84].
- CertifHy is a Europe-wide guarantee of origin scheme for green hydrogen[85].
- A guarantee of origin scheme is under development in Australia for hydrogen[86].

A key feature of any scheme is developing the standards that need to be met for the issue of a certificate. The International Partnership for Hydrogen and Fuels Cells in the Economy (IPHE) has developed a standard for measuring carbon intensity of hydrogen at the point of production. However further work is required for this standard to cover transportation of hydrogen to the end user[87].

New Zealand currently does not have any government-backed renewable certification schemes. Businesses and consumers can trade certificates from the New Zealand Energy Certificate System ("NZECS") for renewable electricity, which is an independent, voluntary certificate scheme[88]. The certificates are separable and can be traded/transferred from generators to energy consumers. However, these certificates do not guarantee additionality of the renewable electricity like equivalent schemes in Europe and Australia. Furthermore, there is no feedback loop to 'true-up' the emissions intensity of the residual electricity supply as renewable electricity is certified. This could lead to underreporting of emission intensity on an aggregate basis across the electricity system.

[82] https://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Power-stations/Eligibility-criteria/eligible-energy-sources
[83] https://www.tuvsud.com/en/press-and-media/2020/february/tuev-sued-provides-greenhydrogen-certification
[84] https://www.greengas.org.uk/
[85] https://www.certifhy.eu/
[86] https://www.cleanenergyregulator.gov.au/Infohub/Markets/guarantee-of-origin#:~:text=The%20Guarantee%20of%20Origin%20%28GO%29%20is%20a%20world-class,range%20of%20products%20such%20as%20metals%20and%20biofuels.
[87] https://www.iphe.net/iphe-wp-methodology-doc-jul-2023
[88] https://www.certifiedenergy.co.nz/how-it-works

However, Toitū Envirocare assessed and concluded the NZECS meets the Greenhous Gas Protocol's Scope 2 Guidance for a market-based mechanism[89].

Renewable gas certification has been available as a product from NZECS since October 2022. Certificates can be issued for biomethane and hydrogen. The nature of the certificate issued, and amount of CO_2 avoided, is based on the results of a lifecycle assessment undertaken by NZECS[90]. Qualifying units of gas production are issued with a certificate that details the carbon intensity of the gas and the date of production. Certificates may be traded and redeemed within the year of production[91].

Gas certification schemes is expected to improve the viability of biogas and green hydrogen production as consumers will be able to claim a premium for renewable gas consumption, thereby making these gases more competitive with natural gas. The key implications relating to certification are summarised in Table 45.

Table 45: Key gas certification implications from changes to the quantity and nature of gas supply

System change	Implications
Biogas	▸ Biogas certification will be required to promote development of biogas facilities as this will support the economics of projects ▸ Schemes will need to be sufficiently robust to be accepted by emissions reporting schemes and flexible enough to cover the various configurations of biogas production and injection into the grid as biomethane
Hydrogen	▸ Hydrogen certification will be required to promote development of electrolysers as this will support the economics of projects ▸ Schemes will need to be sufficiently robust to be accepted by emissions reporting schemes and flexible enough to cover the various configurations of hydrogen production and injection into the grid

6.5 Emissions trading scheme

The Emissions Trading Scheme ("ETS") is the key tool for reducing New Zealand's anthropogenic greenhouse gas emissions. The ETS requires emitters to procure and surrender an NZU for each tonne of CO_2 (equivalent) covered by the scheme. The scheme sets a price on carbon and allows trade of units which incentivises efficient reduction of emissions. A schematic of the ETS is provided in Figure 41.

To meet targets under the Paris Agreement and the Net Zero 2050 target set under the Climate Change Response (Net Zero) Amendment Act 2019, the government limits the supply of NZUs to incentivise emissions reductions. The Climate Change Commission makes recommendations about the emissions budgets (set by the government) which informs the supply of NZUs.[92]

The participants in the scheme may trade NZUs. Most trading occurs on the secondary market or through the government's auctions.[93] Schedule 3 includes the activity of mining natural gas and thus, the NZ ETS imposes a mandatory obligation on upstream producers or importers of natural gas used for transport and stationary energy. Schedule 3 also imposes an obligation on landfill and wastewater treatment plant operators to report and surrender NZUs[94].

NZUs can be created through carbon removal activities. Regulations have been written for carbon removal activities relating to forestry. However, as discussed in Section 6.3, regulations are not in place to allow the creation of units for other carbon removal activities such as through CCUS.

[89] https://www.toitu.co.nz/news-and-events/news/measure/accounting-for-energy-certificates
[90] https://www.certifiedenergy.co.nz/_files/ugd/3e6756_fb7a5678ccfd4d068d80b9b595cb78a9.pdf
[91] https://www.certifiedenergy.co.nz/copy-of-rules-version-2-3
[92] https://www.climatecommission.govt.nz/get-involved/new-content-page/what-is-the-nz-ets/
[93] https://www.etsauctions.govt.nz/public/auction_noticeboard
[94] https://motu-www.motu.org.nz/wpapers/17_05.pdf

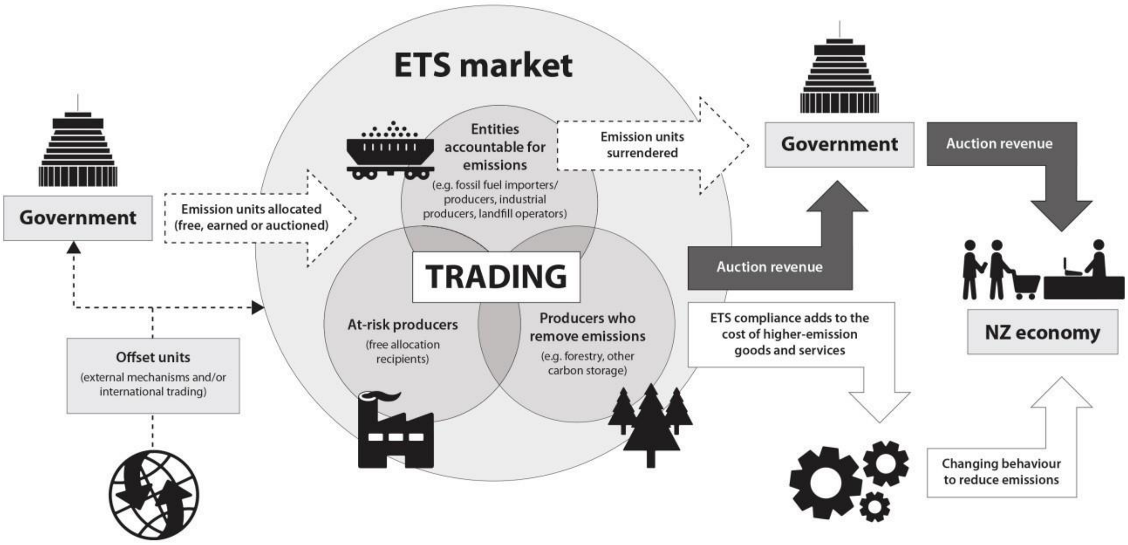

Figure 41: ETS schematic[95]

Historically, the price of an NZU has been highly volatile. Following changes in 2021, prices escalated quickly to over \$80/t CO_2e in December 2022. Recent changes to forestry settings[96] and views on the oversupply of units[97] have caused some relaxation of the carbon price to around \$60/t CO_2e as shown in Figure 42 below.

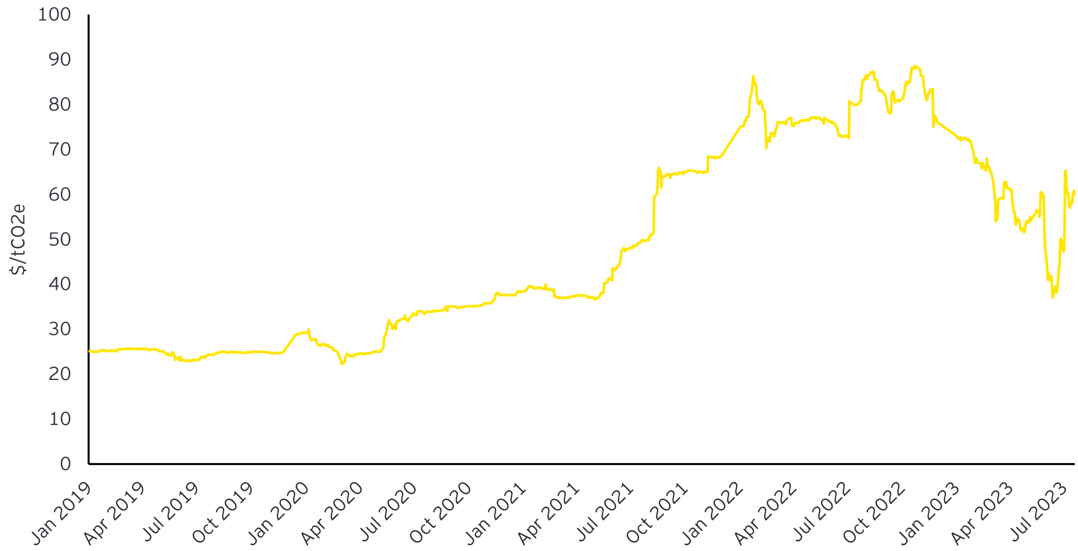

Figure 42: NZU price history

95 https://www.motu.nz/assets/Documents/our-research/environment/climate-change-mitigation/emissions-trading/A-Guide-to-the-New-Zealand-Emissions-Trading-System-2018-Motu-Research.pdf
96 https://businessdesk.co.nz/article/policy/cabinet-makes-initial-steps-to-regulate-carbon-markets
97 https://www.linkedin.com/pulse/nz-ets-tale-two-stockpiles-matthew-cowie/

Long term projections of carbon price show an expectation that NZU prices will continue to rise as emissions budgets are reduced. The Climate Change Commission's Demonstration Path emissions values updated in 2022, are shown in Table 46. While this is not a forecast of price, it shows the levels that prices would need to be to incentivise the emissions reduction in the Climate Change Commission's Demonstration Path scenario.

Table 46: Demonstration Path emissions values[98]

	2025	2030	2035	2040	2045	2050
Emissions value (NZD/t CO_2-e)	$97.50	$144.00	$166.90	$193.50	$224.30	$260

As part of the introduction of the ETS several large gas users are allocated NZUs as they are emissions-intensive, and trade-exposed. The aim of this measure is to maintain international competitiveness of these industries as the same costs may not be borne by these industries overseas[99]. The allocation decreases over time to incentivise emissions reductions by the firm from their baseline in 2006-8[100]. Key gas users that are allocated units are Methanex, Ballance and NZ Steel.

ETS pricing will impact use of the gas systems through the following drivers:

- Increases the price of gas by c. $0.50/GJ for every $10/t CO_2e increase in NZU price encouraging switching away from gas – including to biogas and green hydrogen
- Incentivises reduction in fugitive emissions and flaring by upstream producers
- Could incentivise CCUS uptake
- Could impact the competitiveness of key users

The key gas system implications relating to the ETS are summarised in Table 47.

Table 47: Key ETS implications with changes to the quantity and nature of gas supply

System change	Implications
Natural gas supply	‣ Increases the cost of natural gas ‣ Incentivises switching to other fuels – including green hydrogen and biogas
Biogas	‣ Improves economics of biogas supply relative to natural gas
Hydrogen	‣ Improves economics of green hydrogen supply relative to natural gas
LNG	‣ Increases the cost of LNG ‣ Incentivises switching to other fuels – including green hydrogen and biogas

98 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.climatecommission.govt.nz%2Fpublic%2FAdvice-to-govt-docs%2FERP2%2Fdraft-erp2%2Fsupporting-documents%2FERP2-supporting-spreadsheet-Updated-demonstration-path-and-CPR-2022.xlsx

99 https://www.epa.govt.nz/industry-areas/emissions-trading-scheme/industrial-allocations/#:~:text=An%20industrial%20allocation%20is%20an%20allocation%20of%20units,no%20part%20of%20the%20economy%20is%20unfairly%20affected.

100 https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/ets/participating-in-the-nz-ets/overview-industrial-allocation/

7. Modelled outcomes

7.1 Energy Security

7.1.1 Introduction and methodology

Security of supply is a critical measure of energy sector performance. Aside from storage in Ahuroa[101], which is controlled by private interests, there is no managed reserve of gas supply or ability to direct supply outside *critical contingency events*[102]. When gas supply is low, gas-fired electricity generators may be curtailed, and large industrial consumers may be called on to provide demand response[103]. In contrast, the electricity sector currently has coal fired generators which provide a degree of baseload generation over winter months and a strategic reserve in the event of low hydro storage levels. Liquid fuel supply security is underpinned by minimum onshore stockholding obligations for importers and government procurement of reserves[104]. This section discusses how security of supply is quantified in the gas sector and the outcomes for each scenario.

To quantify security of supply, rather than a simple binary score set by demand being either greater-than or less-than supply, a graduated score has been created, where supply can be less than demand but within a certain tolerance. It is reasonable to include this tolerance because in certain applications fuel switching can occur which mitigates insufficient supply. For example, dry year reserve and baseload gas-fired electricity generation could be substituted with coal-fired generation if the gas supply were insufficient. Although this situation would be highly undesirable, it would not be as bad as industrial consumers needing to shut-down factories. The tolerance has been set as the greater of:

- ► The gas demand for baseload gas-fired electricity generation plus dry year reserve; and
- ► 10% of the total demand.

The 10% floor on this tolerance is required because baseload gas-fired electricity generation is eliminated by 2030 in the *Industry focus* and *Supply headwinds* scenarios. In this way, this study has split demand into '*switchable*' demand and '*non-switchable*' demand to better understand the security of supply impacts of limited supply.

Furthermore, this study considers the security provided by 2P supply as a separate score from security provided by all gas supply (which includes conversion of 2C, biogas, and hydrogen). The reason for breaking down security in this way is because the 2C, biogas, and hydrogen supply all have higher uncertainty than the 2P supply. In this way, the score provides further insights and allows understanding of the key driver of security in any given year of a scenario.

Finally, this study does not consider LNG imports or prospective supply within the security of supply score. The model uses the deficit between supply and demand to calculate the volumes required of either LNG import or prospective supply. For this reason, it does not make sense to include LNG/prospective supply as a form of security because it is an assumed outcome within the model.

The method for calculating of this security score is shown in Table 48 and Figure 43 below. This provides us with a final score for security of supply which sits between zero and four. A score of four indicates that security is very high and there is very little chance of running out of gas. A score

[101] Linepack in the gas network is an additional source of storage but this is very small in the context of annual demand.

[102] https://www.cco.org.nz/#:~:text=The%20role%20of%20the%20Critical%20Contingency%20Operator%20includes,it%20is%20safe%20to%20terminate%20a%20Critical%20Contingency.

[103] The use of demand response to balance supply and demand in the gas sector is common and depends on the nature of long-term gas contracts.

[104] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/liquid-fuel-market/fuel-security-in-new-zealand/

of zero indicates that security is very low and there is a high chance that demand will not be supplied (without LNG and/or prospective supply).

There are certain limitations of this modelling approach and the security of supply score. The security score only considers and compares the volume of demand with the volume of supply in each year of each scenario. The model does not take into consideration storage requirements or network constraints. Furthermore, it does not consider the influence of contractual arrangements within the market. For example, if a large industrial consumer were to exit the market this will reduce demand and thereby appear as an improvement in security. However, if this industrial consumer is underwriting development on the supply side, then this apparent security may be an illusion because supply development will cease. These contractual arrangements were considered when setting the parameters for the different scenarios, but the uncertainty around this issue remains as an important consideration.

Table 48: Description of security of supply score components

2P score	Condition on 2P supply					Description
+2	Total demand	≤	2P supply			2P supply is sufficient to meet total demand
+1	Total demand - tolerance	≤	2P supply	<	Total demand	2P supply is insufficient to meet total demand, but sufficient to meet the non-switchable demand
+0			2P supply	<	Total demand - tolerance	2P supply is insufficient to meet even the non-switchable demand
2P+ score	**Condition on 2P+ supply (2P + 2C + biogas + hydrogen)**					**Description**
+2	Total demand	≤	Total supply			Total supply is sufficient to meet total demand
+1	Total demand - tolerance	≤	Total supply	<	Total demand	Total supply is insufficient to meet total demand, but sufficient to meet the non-switchable demand
+0			Total supply	<	Total demand - tolerance	Total supply is insufficient to meet even the non-switchable demand

Security of supply score = 2P score + 2P+ score

Figure 43: Calculation of the final security of supply score from 2P and 2P+ scores

7.1.2 Outcomes by scenario

In all scenarios, the security of supply score is 4 in 2023. This indicates that the 2P supply (and therefore also 2P+ supply) are able to meet total demand (switchable plus non-switchable) given Methanex's current demand without Waitara Valley.

In the *Industry focus* scenario, shown in the first column of Figure 44, the security of supply score stays at 4 in 2024 then drops in 2025 to 3. This drop in 2025 is due to the reopening of the Waitara Valley methanol plant (a significant increase in demand) which causes the 2P supply to drop below the total demand but stay above the non-switchable demand. The score stays at 3 through to 2026. During this time, 2P supply is able to meet the non-switchable demand and 2P+ supply is able to meet total demand. In 2027, the score drops to 2. This is because 2P supply drops below the non-switchable demand in 2027. The score stays at 2 until 2031. In 2032, the score drops to zero as neither 2P nor 2P+ supply is able to meet the non-switchable demand.

In the *Methanex exits early* scenario, this study has assumed the closure of Methanex is signalled in advance and therefore there is less 2P supply and all conversion of 2C resources is deferred. For this reason, as shown in the second column of Figure 44, security of supply score drops to 2 in 2024 and stays there in 2025. At this score, 2P supply (and therefore also 2P+ supply) is able to meet non-switchable demand but insufficient to meet total demand. In 2026 the score drops to zero, indicating that neither 2P nor 2P+ supply is able to meet even the non-switchable demand, let alone total demand. This occurs earlier than the assumed lead time on LNG imports within the model, so this presents a scenario wherein significant demand curtailment would be required. In 2029, when Methanex exits, the score increases to 2. In 2029 and 2030, 2P supply (and therefore also 2P+ supply) is able to meet non-switchable demand but insufficient to meet total demand. This study assumes that, beyond 2030 with demand somewhat stabilised (albeit at a much lower level), the conversion of 2C conversion would restart. In 2031, the 2P supply drops below the non-switchable demand but the 2P+ supply (with boosted 2C conversion) is able to meet total demand, therefore the score stays at 2.

Because of the crucial role that Methanex plays in underwriting supply side development, the security of supply in the *Methanex exits early* scenario is particularly uncertain. If Methanex were to close its operations in New Zealand, it may be necessary for smaller consumers to band together on large, fixed offtake contracts to provide greater certainty for the suppliers.

In the *Elevate electricity* scenario, shown in the third column of Figure 44, the security of supply score stays at 4 through to 2026 then drops in 2027 to 3. The high security in the early years of this scenario is driven by low demand in the industrial, commercial, and residential sectors. The drop in 2027 is due to the 2P supply dropping below the total demand but staying above the non-switchable demand. This drops again to 2 in 2028 as 2P supply drops below the non-switchable demand. From 2023 right through till 2031, results show 2P+ supply able to meet total demand. This situation changes in 2032 when 2P+ supply drops below total demand but stays above non-switchable demand, meaning the score drops to 1. The situation changes again in 2033 when 2P+ supply drops below the non-switchable demand and the score drops to zero.

In the *Supply headwinds* scenario, shown in the fourth column of Figure 44 the security of supply drops to 2 in 2024. In 2024 and 2025, results show both 2P and 2P+ supply dropping below total demand but staying above the non-switchable demand. In 2026, 2P supply drops below non-switchable demand, but 2P+ supply picks up and is able to meet total demand through till 2030. The score therefore stays at 2. In 2031, the score drops to zero as 2P+ is no longer able to meet even the non-switchable demand. The score increases to 1 in 2035 as one of the Motunui methanol trains close.

Looking across the scenarios results show 2P supply being unable to meet total demand at some stage between 2025 and 2030. Furthermore, the 2P+ supply may also be insufficient to meet demand as early as 2030. Results show that scenarios with suppressed supply side development (*Methanex exits early* and *Supply headwinds*) have lower security in the early years. This intuitive finding potentially indicates the risk of demand being unmet due to low supply. Moreover, while this study has characterised some demand as 'switchable' there will be implications to this switching. For example, the use of coal for power generation will lead to higher emissions. For industrial demand, this could lead to increased production costs and loss of comparative advantage in some industries. It could also put pressure on the electricity market to accelerate its transition to a 100% renewable supply mix due to lower gas supply.

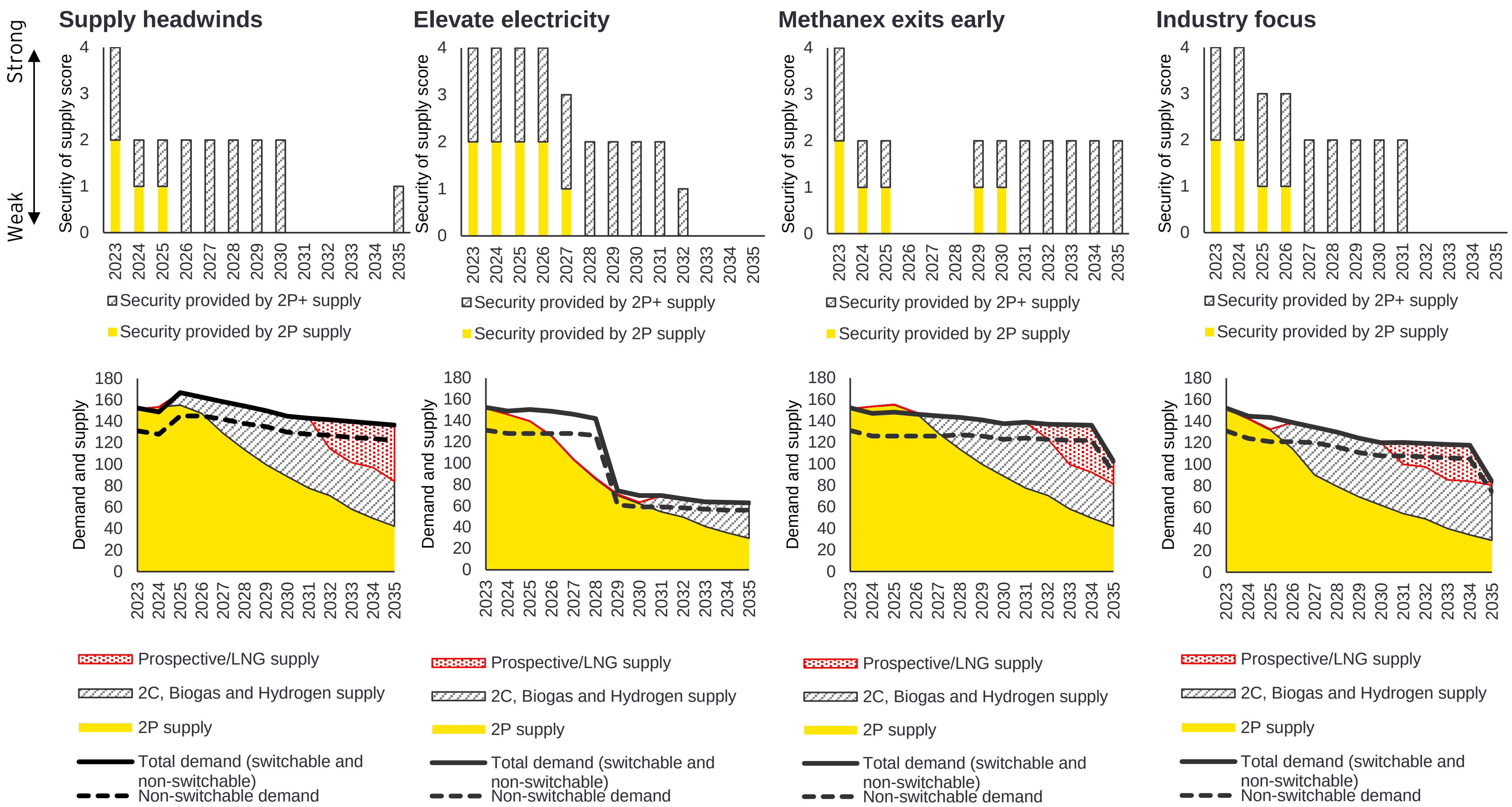

Figure 44: Security of supply score per scenario (top row) and supply demand balance per scenario (bottom row). Note that the whitespace between demand and supply indicates a shortfall in supply.

7.2 Price Outcomes

7.2.1 Introduction and methodology

With significant changes on the horizon for both the supply and demand side of the gas sector, it is important to understand the outcomes for gas prices. The average residential consumer's bill in 2022 was around $1,200 for the year[105]. There are a number of different components that make up this total bill, some of them fixed costs and others variable. The components include wholesale gas price, retail, metering, regulator levies, transmission, distribution, and carbon costs. A description of these components is below:

- **Retail, metering, UFG, and regulator:** Covers the retailers charges, the cost of monitoring and maintaining gas meters, any unaccounted-for-gas (UFG), and regulator levies.
- **Distribution:** Covers the cost incurred by the gas distribution network which takes gas from the transmission system and pipes it around cities and urban centres.
- **Transmission:** Covers the cost incurred by the gas transmission network which takes gas from the supply region (Taranaki) to a consuming region, for example Auckland, Wellington, Hawke's Bay, Manawatu, etc.
- **Wholesale:** Covers the upstream cost of identifying, extracting, and producing the gas.
- **Carbon:** Covers the cost of carbon emissions through the emissions trading scheme.

This section presents the outcome of the gas price forecast. Where carbon costs are incurred, this study has assumed the Climate Change Commission's carbon price forecast to estimate this component. For the purposes of comparison, this study has included the current day cost for the other components. However, this study has not included these other components within the modelling, rather this study assumes a static forecast based on the current day costs. It is important to include these additional costs within the cost estimate because, for residential consumers, they represent most of the cost. However, it is beyond the scope of this analysis to provide a forecast of these other components. The methodology includes a variety of factors that place either upwards or downwards pressure on pricing as outlined in Table 49.

Table 49: Factors which influence the price of supplied gas.

Factor	Impact
Lower overall production volumes	Lower production results in higher per-unit costs. This study assumes a 64%:36% split between fixed and variable costs[106]. The fixed costs reduce when fields close.
Development of 2C resources	2C resources require higher investment to extract and convert to production. This leads to higher per-unit costs.
Field closures	Closure of natural gas fields results in a drop of fixed costs.
Increased carbon pricing	Increased carbon pricing leads to higher carbon costs, in proportion to the emissions from each supply source.
Increased penetration of renewable (low carbon) gases	Biogas and hydrogen have different (typically higher) costs of production than natural gas. They do however avoid the carbon cost, either wholly or partially.
Feedstock for the biogas	Certain feedstocks, such as wastewater, landfill gas, and municipal biogas, are readily available and cheap. However, they are limited in total potential supply. This study

[105] Number sourced from private communications with GIC

[106] Based on discussions with field operators.

	assumes a price stack for biomass as in the Gas Transition Plan – Biogas Research Report[107]

7.2.2 Outcomes by scenario

In all scenarios, the cost of gas increases. This is due to a number of factors; an increase in natural gas production costs as production volumes decline; increasing penetrations of biogas, hydrogen, and LNG, all of which are presently more expensive than indigenous natural gas; conversion of 2C resources to production; and increasing carbon price. The price of gas is shown in Figure 45 for small and large residential consumers. The scenario with the smallest price rise is the *Industry focus* scenario where prices rise by around 21.5% in real terms between now and 2035. The scenario with the highest price rise is the *Supply headwinds* scenario where prices rise by around 39.7% in real terms between now and 2035.

The different supply sources (natural gas or methane, biogas, hydrogen, and LNG) have slightly different costs across the four different scenarios. This is because they have different levels of production in each scenario which affects their price. This is shown in the top row of Figure 46. Biogas shows the most significant increase in price. This is because the price stack for biogas rises reasonably sharply with increasing biogas production. As cheaper sources, such as wastewater, landfill gas, and municipal biogas, are exhausted more expensive options are required. However, biogas does have the advantage of having a lower carbon cost. This can be seen in the bottom row of Figure 46 which shows the volume weighted average price within each scenario. These are calculated from the fractional volume of gas supplied by each source (natural gas or methane, biogas, hydrogen, and LNG) multiplied by the cost each source. The charts include both commodity and carbon costs for each source. So, for example, one can see the rising carbon prices leading directly to a higher carbon component for methane and LNG, but considerably smaller carbon component for biogas and hydrogen as these are low carbon fuels.

Overall, results show the lowest prices in the *Industry focus* and *Elevate electricity* scenarios. This is because natural gas supply is kept sufficiently high to avoid the worst of the price increases (as occurs in the *Methanex exits early* and the *Supply headwinds* scenarios, where natural gas prices approximately double). The LNG component creates material price increases if or when it is required.

In the *Industry focus* scenario, results show the residential cost of gas for small residential users increases by approximately 21.5% between now and 2035, as seen in Figure 45. This is driven by a 88.5% increase in the wholesale cost of gas (including carbon costs), which comes from higher carbon prices and a material LNG/prospective supply component. This is seen in the first column of Figure 46.

In the *Methanex exits early* scenario, results show the residential cost of gas for small residential users increases by approximately 26.1% between now and 2035, as seen in Figure 46. This is driven by a 102.7% increase in the wholesale cost of gas (including carbon costs), which comes from higher carbon prices, a significant increase.in the cost of natural gas, and a material biogas component. This is seen in the second column of Figure 46.

In the *Elevate electricity* scenario, results show the residential cost of gas for small residential users increases by approximately 21.7% between now and 2035, as seen in Figure 45. This is driven by a 88.7% increase in the wholesale cost of gas (including carbon costs), which comes from higher carbon prices and a material LNG/prospective supply component. This is seen in the third column of Figure 46.

In the *Supply headwinds* scenario, results show the residential cost of gas for small residential users increases by approximately 39.7% between now and 2035, as seen in Figure 46. This is driven by a 153.3% increase in the wholesale cost of gas (including carbon costs), which comes from higher

[107] https://www.mbie.govt.nz/dmsdocument/27267-gas-transition-plan-biogas-research-report-february-2023-pdf

carbon prices and material components of both biogas and LNG/prospective supply. This is seen in the fourth column of Figure 46.

A comparison of residential user costs in 2025 and 2035 is given in Table 50 for small users and Table 51 for large users.

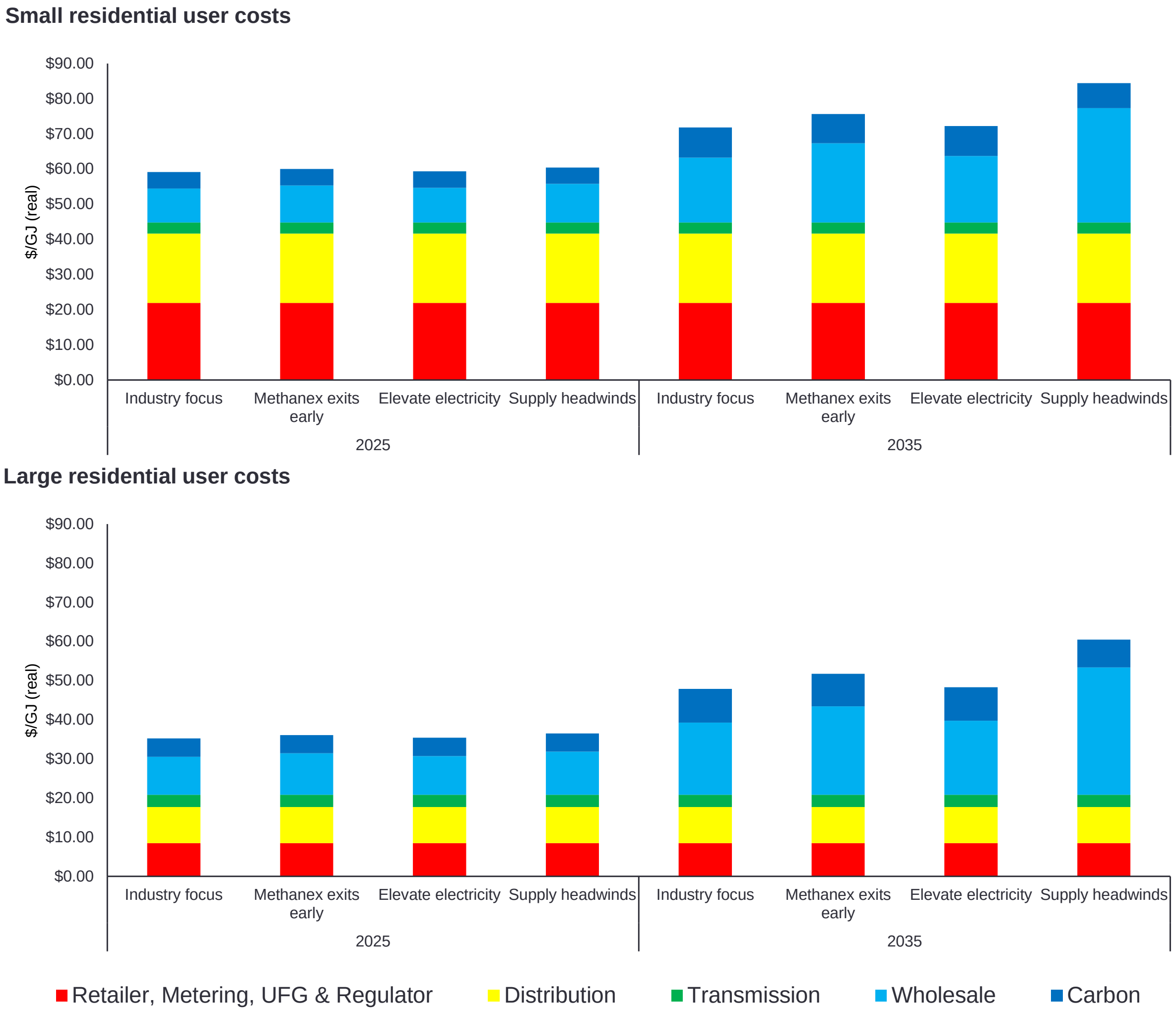

Figure 45: Gas price for small and large residential consumers in 2025 and 2035[108]

Table 50: Small residential user costs

$/GJ (real)	Industry focus		Methanex exits early		Elevate electricity		Supply headwinds	
	2025	2035	2025	2035	2025	2035	2025	2035
Retailer, Metering, UFG & Regulator	$21.94	$21.94	$21.94	$21.94	$21.94	$21.94	$21.94	$21.94
Distribution	$19.67	$19.67	$19.67	$19.67	$19.67	$19.67	$19.67	$19.67
Transmission	$3.17	$3.17	$3.17	$3.17	$3.17	$3.17	$3.17	$3.17
Wholesale	$9.68	$18.42	$10.55	$22.56	$9.86	$18.88	$10.98	$32.54
Carbon	$4.68	$8.64	$4.67	$8.31	$4.68	$8.54	$4.66	$7.07

Table 51: Large residential user costs

[108] The wholesale component in this price is an energy-weighted average across the different supply sources

$/GJ (real)	Industry focus		Methanex exits early		Elevate electricity		Supply headwinds	
	2025	2035	2025	2035	2025	2035	2025	2035
Retailer, Metering, UFG & Regulator	$8.48	$8.48	$8.48	$8.48	$8.48	$8.48	$8.48	$8.48
Distribution	$9.21	$9.21	$9.21	$9.21	$9.21	$9.21	$9.21	$9.21
Transmission	$3.17	$3.17	$3.17	$3.17	$3.17	$3.17	$3.17	$3.17
Wholesale	$9.68	$18.42	$10.55	$22.56	$9.86	$18.88	$10.98	$32.54
Carbon	$4.68	$8.64	$4.67	$8.31	$4.68	$8.54	$4.66	$7.07

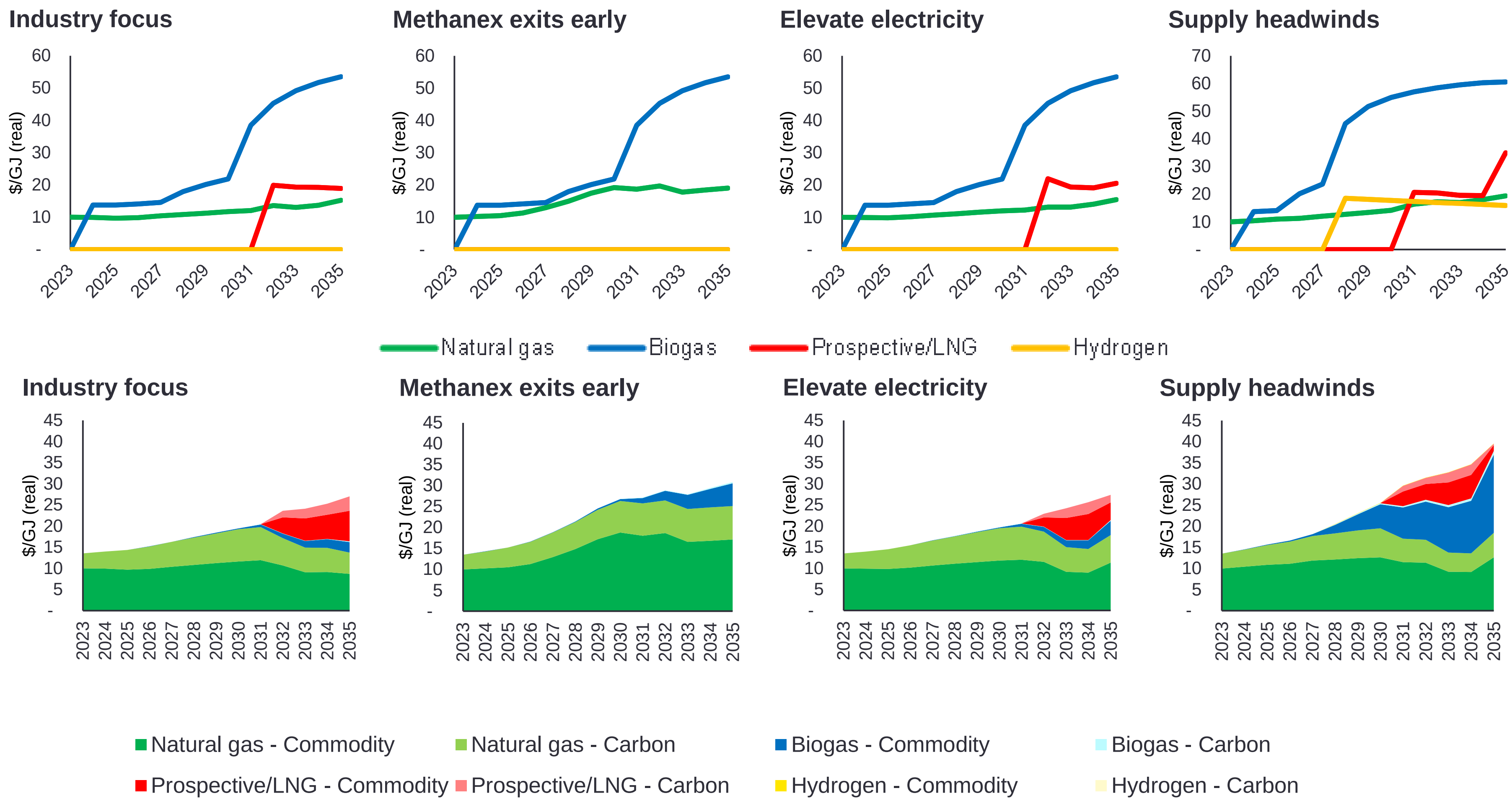

Figure 46: Fuel costs across the different fuels (top row) and Energy-weighted average price (bottom row) in each scenario

7.3 Emissions impacts

7.3.1 Introduction and methodology

Emissions from the extraction, transport, and consumption of fossil fuels, including natural gas, are causing catastrophic damage to our planet. New Zealand is united toward achieving the goal of net zero emissions by 2050, and dramatic reductions are required from the gas sector to get there.

Emissions in each of the scenarios are categorised and quantified in the following way:

- **Upstream emissions:** CO_2 (or CO_2-equivalent) emissions that occur during the extraction and production of gas. These include emissions from flaring, CO_2 venting, gas venting, and fugitive emissions.
- **Midstream emissions**: CO_2-equivalent emissions that occur while transporting the gas through transmission and distribution networks.
- **Downstream emissions:** CO_2 (or CO_2-equivalent) emissions that occur during the end use of the gas. These are primarily combustion emissions but may include emissions from other end uses, such as process emissions. This category of emissions can be further subdivided by the different types of demand, as discussed in Section 4.
- **Carbon capture and utilisation or sequestration:** Can occur on the upstream or downstream emissions. For a detailed discussion, see Section 6.3.

Figure 47 shows a schematic of the emissions model.

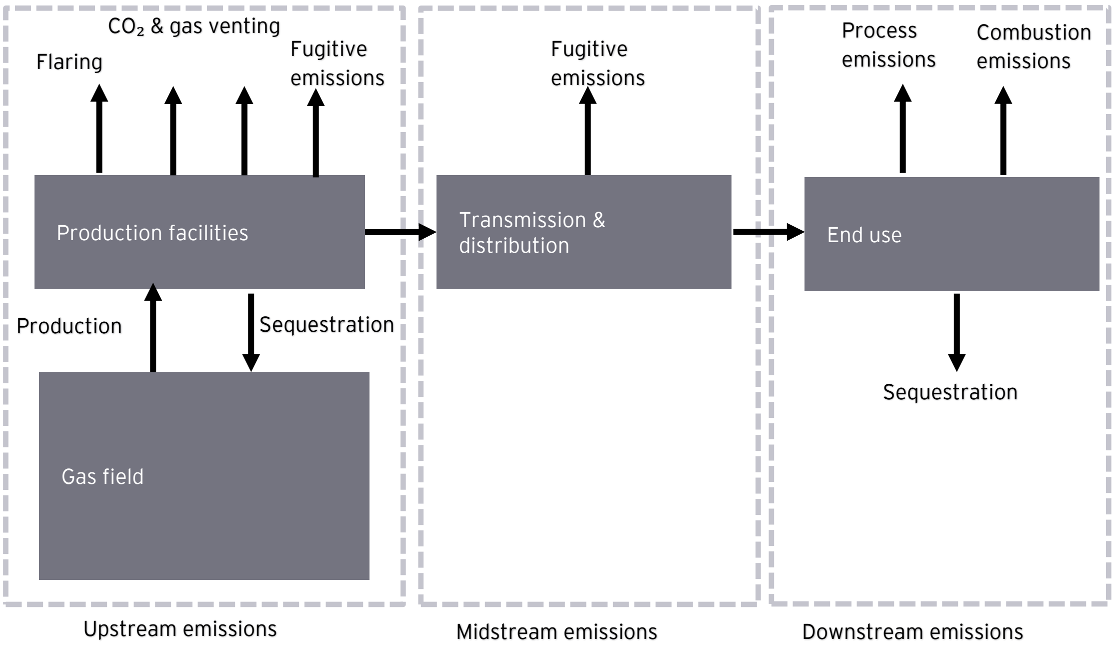

Figure 47: Emissions model schematic

7.3.2 Outcomes by scenario

Figure 48 shows both the annual (left chart) and cumulative (right chart) emissions across the different scenarios. These are gross emissions and do not assume any CCUS. In all scenarios results show annual emissions reducing over the modelling period. The charts compare the emissions to the Climate Change Commission's (CCC) demonstration path modelling and find the scenarios are in reasonable agreement. The highest emission scenario is the *Elevate electricity* scenario which has approximately 3.1 million tonnes of additional CO_2 emissions (cumulative from 2023 to 2035) than the CCC demonstration path. This is approximately 4.2% higher emissions. The lowest scenario is the *Supply headwinds* scenario which has approximately 11.5 million tonnes of fewer CO_2 emissions (cumulative from 2023 to 2035) compared to the CCC demonstration path. This is approximately 15.3% lower emissions (noting that this only accounts for gas).

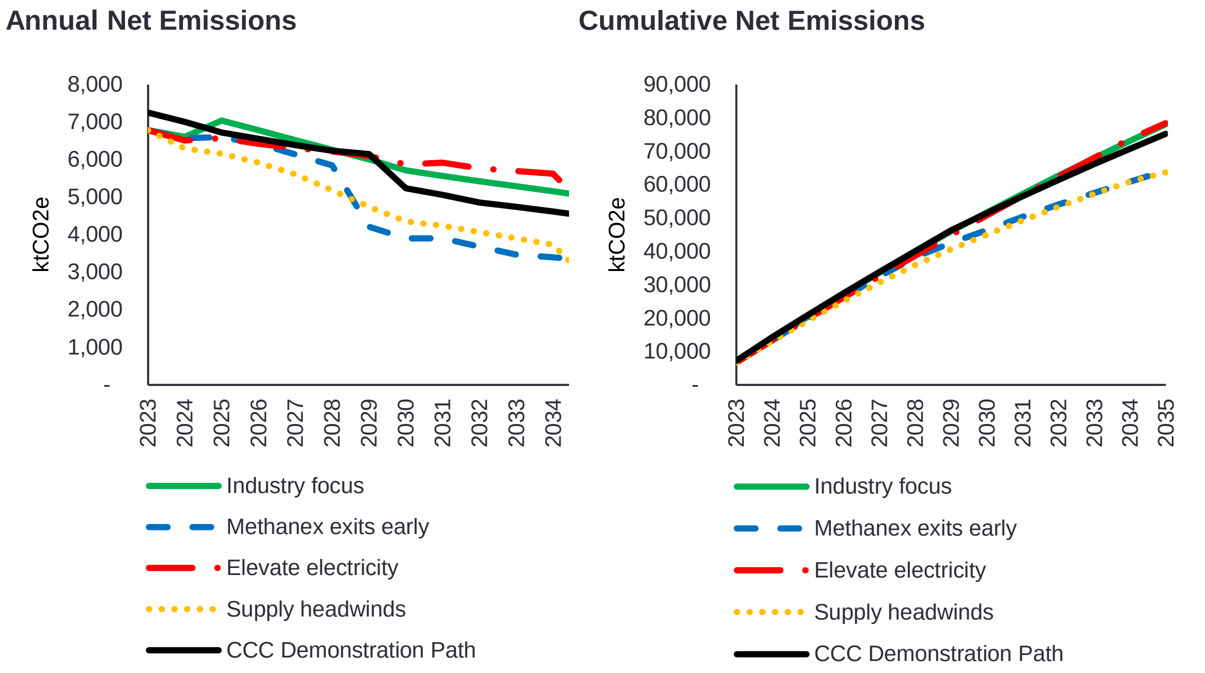

Figure 48: Annual emissions (left chart) and the cumulative emissions (right chart) across the scenarios

Figure 49 shows the annual and cumulative emissions broken down by categories (upstream, midstream, Ballance, Methanex, electricity, residential, commercial, and industrial). These charts provide insights around where the major source of emissions is coming from and what is changing between now and 2035 to reduce emissions.

In the *Industry focus* scenario, results show the cumulative emissions (from 2023 to 2035) is approximately 2.8 million tonnes of CO_2 greater than the CCC demonstration path and an increase of approximately 3.8%. From Figure 49, results show that higher emissions in this scenario are due to Methanex, which is operating all three production plants. Due to the high efficiency of Methanex's New Zealand plants, these additional emissions may not occur in a global accounting exercise.

In the *Methanex exits early* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 11 million tonnes of CO_2 fewer emissions as compared to the CCC demonstration path. This is approximately 14.7% lower emissions. From Figure 49, results show the lower emissions in this scenario is due to Methanex closing early. As discussed above, Methanex's emissions should be considered in the context of global emissions rather than domestic emissions. It is considered unlikely that closing Methanex's New Zealand plants would reduce global emissions.

In the *Elevate electricity* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 3.1 million tonnes of CO_2 additional emissions as compared to the CCC demonstration path. This is approximately 4.2% higher emissions. From Figure 49, results show the higher emissions in this scenario come from higher use of gas in the electricity generation mix.

In the *Supply headwinds* scenario, results show the cumulative emissions (from 2023 to 2035) has approximately 11.5 million tonnes of CO_2 fewer emissions as compared to the CCC demonstration path. This is approximately 15.3% lower emissions. From Figure 49, results show the lower emissions in this scenario come from lower industrial demand and lower use of gas in the electricity generation mix. It is noted that this analysis only accounts for emissions from gas. It does not include emissions from additional consumption of coal, diesel, or otherwise that may be required in the event of gas supply being unavailable. If high emissions fuels were substituted for gas due to supply constraints, this would lead to higher emissions in this scenario.

7.3.3 Potential for carbon capture and utilisation or storage

The potential for CCUS to reduce emissions provides an opportunity for New Zealand to accelerate its emissions reduction, take advantage of its remaining gas reserves without compromising on the emissions budget, and maintain a competitive advantage for trade exposed, emissions intensive industries.

Figure 49 also shows a sensitivity to the *Industry focus* scenario where a limited amount of CCUS has been deployed The most apparent application of CCUS is to reduce upstream emissions. Recent estimates suggest reductions of approximately 460 kt of CO_2 in 2035 from upstream emissions alone[109]. Outside of upstream applications, the viability of CCUS is linked to high on-site gas demand, high CO_2 concentration in the flue gas, and access to nearby sequestration. These factors point to certain Taranaki-based industries being well placed to take up CCUS. CCUS is gaining momentum internationally due to tax incentives in the Inflation Reduction Act[110]. New Zealand has seen recent activity in CO_2 reinjection at geothermal power plants[111]. In Figure 49, where CCUS is shown, this study has assumed 236 kt of CO_2 from upstream emissions (approximately 50% of the total) and 629 kt of CO_2 from petrochemical emissions (approximately 35% of the total) are sequestered. This assumption gives the Motunui and Waitara Valley methanol plants a net emissions factor of around 0.5 tonnes of CO_2 per tonne of methanol, which is comparable though still materially higher than the Geismar 3 project[112] which is estimated to be less than 0.4.

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[109] https://www.mbie.govt.nz/dmsdocument/27264-review-of-ccus-ccs-potential-in-new-zealand-march-2023-pdf
[110]
https://www.iea.org/policies?topic=Carbon%20Capture%20Utilisation%20and%20Storage&region%5B0%5D=North%20America
[111] https://www.energynews.co.nz/news/geothermal/125507/geothermal-generators-team-carbon-reinjection
[112] https://www.methanex.com/geismar-3/

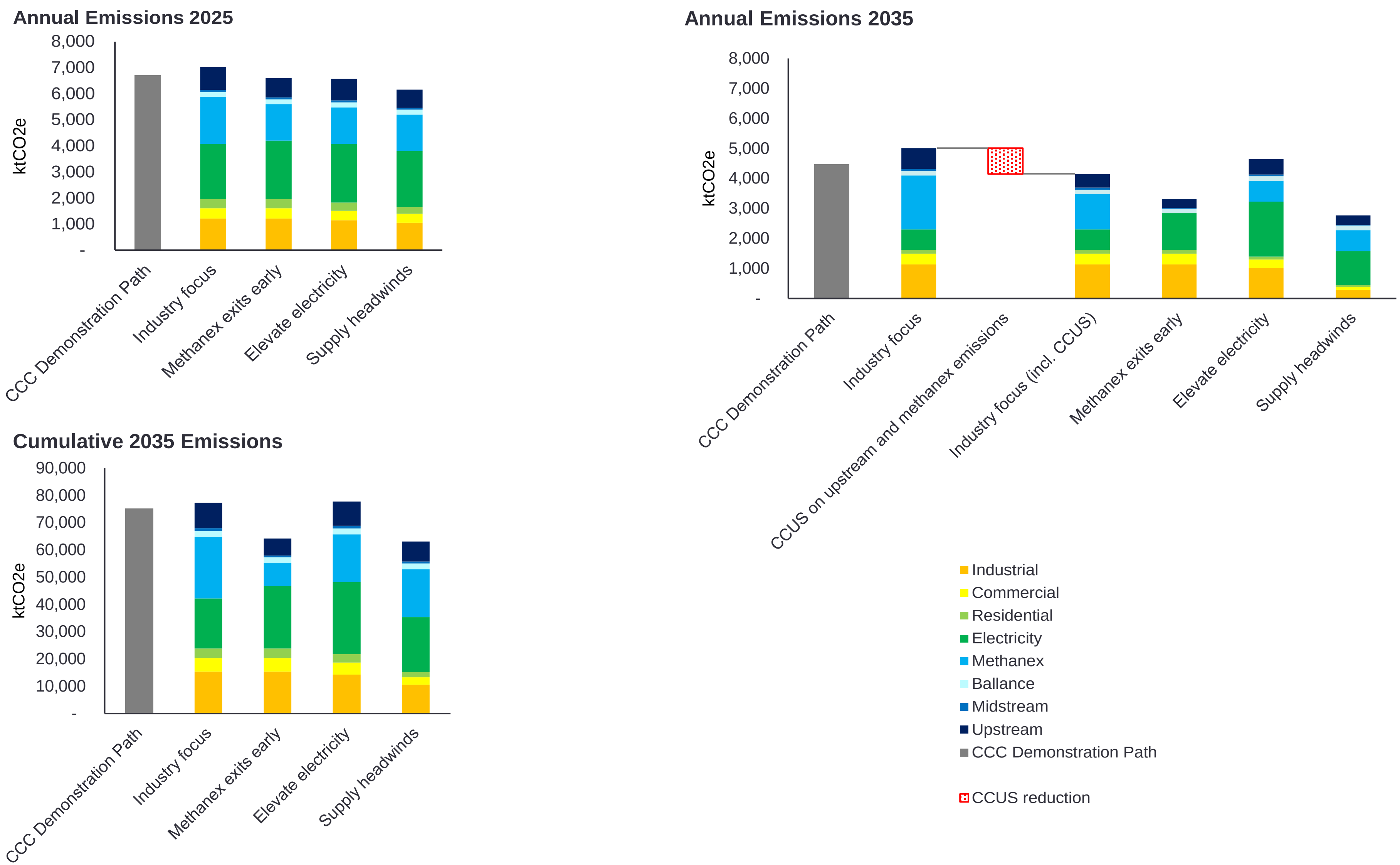


Figure 49: Annual and cumulative emissions by scenario broken down into categories

Appendix A Modelling assumptions

The purpose of this appendix is to provide an outline of the assumptions underlying the natural gas supply and demand model developed by EY. This appendix includes the modelling assumptions and data sources for:

- Demand model assumptions
- Supply model assumptions
- Price outcomes and emissions model assumptions

A.1 Demand model assumptions

The following section provides an overview of the assumptions that are used to model demand for natural gas.

Total natural gas demand is separated into the following sources:

- Petrochemical industry
- Gas-fired electricity generation
- Sectoral demand

Assumptions for each source (where they have not been covered in the main body of the report) are discussed in the following sections.

A.1.1 Petrochemical industry demand assumptions

The natural gas demand for petrochemicals is made up by demand from Methanex and Ballance as outlined below.

A.1.2 Methanex

The modelling assumes the average annual demand of each Methanex plant as shown in Table 52. These are based on the capacity of each plant, with an assumed 7% outage rate to allow for maintenance.

Table 52: Assumed average annual demand for each Methanex plant

Plant	Assumed demand
Motunui 1	32.6 PJ/yr
Motunui 2	32.6 PJ/yr
Waitara Valley	18.6 PJ/yr

The demand for each plant is assumed to be constant when it is operating, which means any change in the demand from Methanex is driven by the openings and closures dates for each plant. The assumed opening / closure dates for each plant are as described in Table **53**.

Table 53: Methanex plant opening and closure dates

Scenario	Motunui 1 closes	Motunui 2 closes	Waitara Valley reopens	Waitara Valley closes
Industry focus	2045	2060	2025	2040
Methanex exits early	2029	2029	-	-
Elevate electricity	2035	2040	-	-
Supply headwinds	2035	2040	-	-

A.1.3 Ballance

Ballance has two sources of demand in its operations: feedstock and process heat. Demand is split equally between this demand. Ballance is assumed to continue operating at historical levels (7.3 PJ/yr) throughout the modelled period. However, its demand is assumed to reduce over time through a two-stage decarbonisation process. Stage 1 of this is focused on removing the process heat demand through electrification and is assumed to occur in the near-term, resulting in a 17% reduction in total demand (1.24 PJ/yr) upon implementation. Stage 2 requires replacing the Steam Methane Reforming (SMR) process with a hydrogen electrolyser and is assumed to occur later and at different rates of implementation, but ultimately results in Ballance's demand for natural gas being reduced to effectively zero upon the completion of stage 2.

The assumed timings for the implementation of each stage, and the resulting reductions in demand, are outlined in Table 54.

Table 54: Assumed timings and resulting demand reductions for stages 1 and 2 of Ballance's decarbonisation programme for each scenario

Scenario	Stage 1 Complete	Stage 1 reduction (one-off)	Stage 2 start	Stage 2 reduction[113]	Stage 2 complete
Industry focus	2030	17%	2042	5%	2058
Methanex exits early	2028	17%	2036	10%	2044
Elevate electricity	2029	17%	2039	7%	2047
Supply headwinds	2029	17%	2039	7%	2047

[113] Percentage of initial demand reduction achieved each year

A.1.4 Electricity generation demand assumptions

A.1.5 Heat rate assumptions

The electricity demand assumptions are driven off electricity generation profiles (measured in TWh). To convert these to natural gas demand figures (measured in PJ), the heat rates described in Table 55 are used.

Table 55: Heat Rate Assumptions used for electricity generation

Generation type	Heat rate	Source
Baseload	7.40 GJ/kWh	MBIE Thermal Generation Stack
Peaking	10.50 GJ/kWh	MBIE Thermal Generation Stack
Cogeneration	13.38 GJ/kWh	MBIE Electricity & Gas Statistics
Dry Year	10 GJ/kWh	Mix of baseload and peaking, weighted higher towards peaking.

A.1.6 Baseline electricity demand

A baseline electricity demand profile was constructed using the average of the Climate Change Commission's 2021 modelling dataset[114] and Transpower's 2020 Whakamana I Te Mauri Hiko dataset[115][116]. The resulting baseline generation profile is shown in Figure 50. This includes generation from both natural gas-fired baseload and peaking generators but excludes cogeneration. It also assumes the NZ Aluminium Smelter remains throughout the modelling period.

114 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.climatecommission.govt.nz%2Fpublic%2FInaia-tonu-nei-a-low-emissions-future-for-Aotearoa%2FModelling-files%2FTiwai-point-sensitivity-dataset-final-advice-2021.xlsx

115 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fstatic.transpower.co.nz%2Fpublic%2Funcontrolled_docs%2FWhakamana%2520i%2520te%2520Mauri%2520Hiko%2520data%2520report%2520figures.xlsx%3FVersionId%3DB1w9nnzgfdbvZW71kWkWhLbFay6VqZvf

116 The Transpower forecast only goes out until 2040, so the Baseline assumption converges on the CCC forecast after 2040.

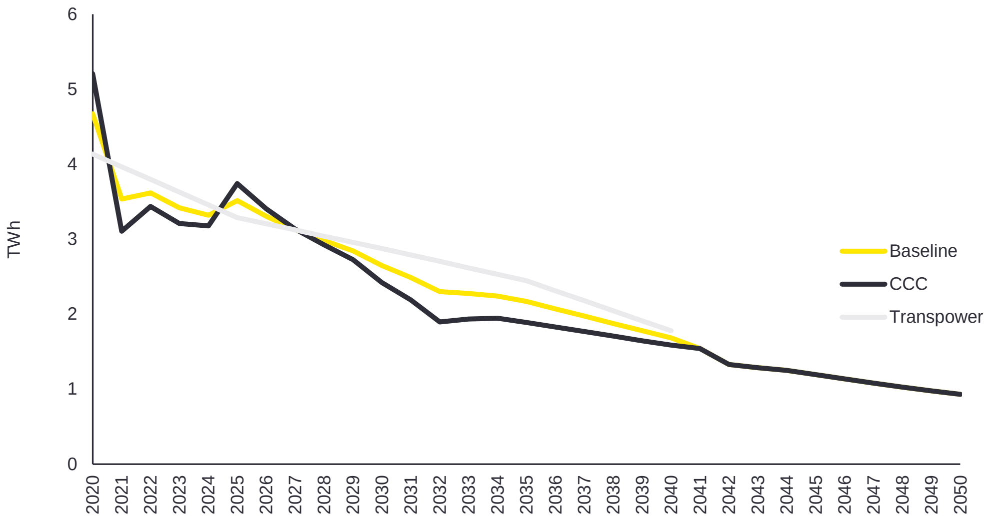


Figure 50: Baseline electricity demand as an average of the 2021 CCC modelling dataset and 2020 Transpower Whakamana I Te Mauri Hiko datasets

While this baseline is used as a starting point for all scenarios, the assumptions made in each scenario means that the amount of natural gas-fired generation does deviate from this baseline in most scenarios at some point in the future. The assumptions for the mix of peaking and baseload generation, and how this changes over time in each scenario, are described below.

A.1.7 Peaking electricity demand

Natural gas-fired peaking generation is expected to play an increasingly important role in the electricity generation mix moving forward as it provides important firming for increasing amounts of intermittent renewable generation. The demand for peaking generation was developed by analysing the historical[117] peaking electricity generation. Over the last decade, peaking generation has increased from around 240 GWh in 2011 to around 1,000 GWh in 2017, as shown in Figure 51.

[117] https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD

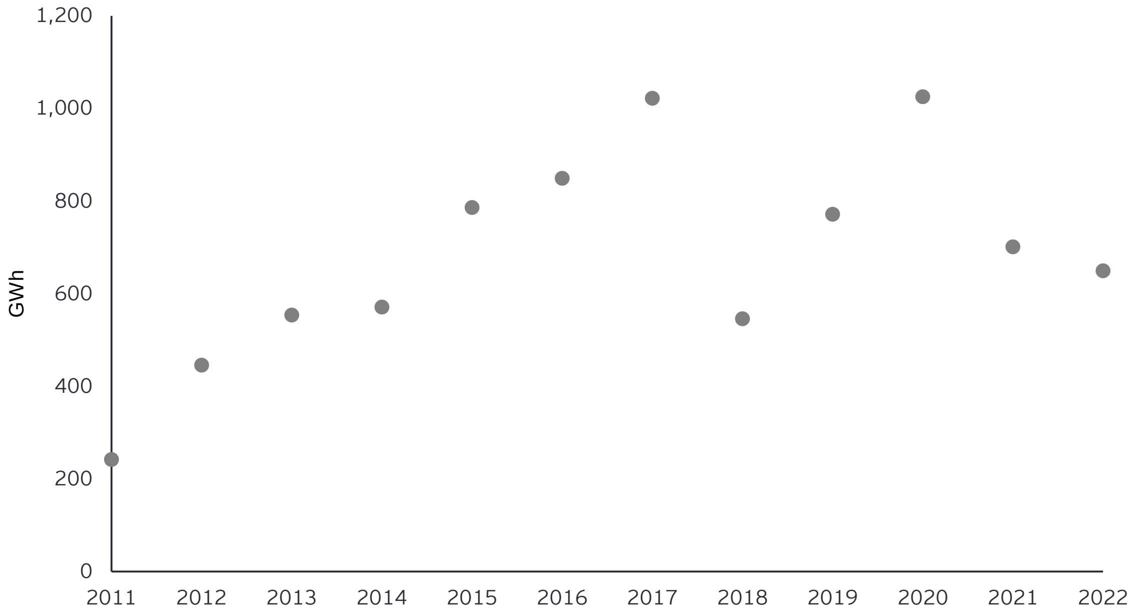


Figure 51: Historical Electricity Peaking Generation

However, demand for peaking can be reduced in wetter years (such as 2022 where peaking generation dropped to 650 GWh). Furthermore, other firming technologies (such as batteries) are also expected to increase to provide some firming which has the potential to offset natural gas-fired peaking in some cases. As a result, this study has assumed that demand for natural gas-fired peaking continues at its historical peak of 1 TWh in the short term for all scenarios. While it might not be necessary to utilise the full 1 TWh of peaking generation each year, it's crucial to ensure fuel availability annually for occasions when peak generation is demanded. The assumptions for how peaking generation varies under each scenario are described in Table 56.

Table 56: Peaking generation assumptions for each scenario

Scenario	Modelling assumptions
Industry focus	▸ 2023-2030: Constant 1 TWh of peaking generation based on historical data ▸ 2031-2040: Peaking demand decreases linearly to 0 TWh in 2040
Methanex exits early	▸ 2023-2040: Constant 1 TWh of peaking generation based on historical data ▸ 2041-2050: Peaking demand decreases linearly to 0 TWh in 2050
Elevate electricity	▸ 2023-2025: Constant 1 TWh of peaking generation based on historical data ▸ 2025-2038: Peaking generation increases to 100% of the baseline generation profile ▸ 2038-2050: Continues at 100% of the baseline generation profile
Supply headwinds	▸ 2023-2040: Constant 1 TWh of peaking generation based on historical data ▸ 2041-2050: Peaking demand decreases linearly to 0 TWh in 2050

A.1.8 Baseload electricity demand

The starting assumption for all scenarios is that baseload generation makes up the remaining portion of the baseline profile (e.g., baseline generation in each year – peaking generation). Additionally, baseload generation is assumed to be phased out in some scenarios. The assumptions for baseload generation for each scenario are described in Table 57.

Table 57: Baseload generation assumptions for each scenario

Scenario	Modelling assumptions
Industry focus	▸ 2023-2025: Baseline generation profile minus peaking generation ▸ 2026-2030: Baseload generation linearly reduces to 0 TWh
Methanex exits early	▸ 2023-2025: Baseline generation profile minus peaking generation ▸ 2026-2033: Baseload generation linearly reduces to 0 TWh
Elevate electricity	▸ 2023-2050: Baseline generation profile minus peaking generation ▸ (Note: in this scenario, peaking generation is increased to 100% of the baseline generation profile, meaning at this point baseload generation is reduced to 0 TWh)
Supply headwinds	▸ 2023-2025: Baseline generation profile minus peaking generation ▸ 2026-2033: Baseload generation linearly reduces to 0 TWh

A.1.9 Cogeneration electricity demand

The nature of Cogeneration being combined with heat and electricity generation means its output is driven by the process heat requirements and is relatively constant. This is confirmed when analysing historical cogeneration outputs as shown in Figure 52[118].

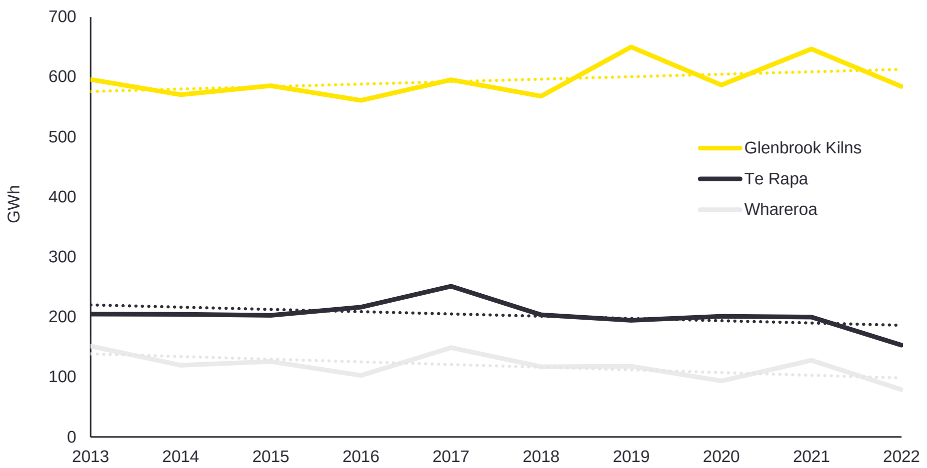


Figure 52: Historical Cogeneration

The continued generation of existing cogeneration plants (Glenbrook Kilns, Te Rapa and Whareroa[119]) at historical output levels is the starting point for all scenarios. It is assumed that no new generation is built. Hence, cogeneration is driven by the operating levels and retirement dates of these existing plants. The assumed baseline output based on the historical data for each plant is provided in Table 58.

[118] Source for historical data is: https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD

[119] Ballance also have a cogeneration plant at Kapuni but this demand has been included in the petrochemical demand, so it has been excluded here to avoid double counting.

Table 58: Cogeneration baseline output based on historical values

Cogeneration plant	Annual baseline output
Glenbrook Kilns	594 GWh
Te Rapa	203 GWh
Whareroa	118 GWh

The assumptions for how output varies over time and the assumed retirement dates of the plant under each scenario are described in Table 59.

Table 59: Cogeneration assumptions for each scenario

Scenario	Cogeneration operating demand assumptions	Retirement date assumptions
Industry focus	2023-2025: Demand continues at historical levels across all plants 2025-2030 Demand is reduced to 80% historical demand across all plants 2031-2035: Demand is further reduced to 60% across all plants	Glenbrook Kilns: 2035 Te Rapa: 2024 Whareroa: 2035
Methanex exits early	2023-2029: Cogeneration continues at historical levels across all plants 2030-onwards: Cogeneration is reduced to 80% historical demand across all plants	Glenbrook Kilns: 2047 Te Rapa: 2024 Whareroa: 2038
Elevate electricity	2023-2029: Cogeneration continues at historical levels across all plants 2030-onwards: Cogeneration is reduced to 80% historical demand across all plants	Glenbrook Kilns: 2047 Te Rapa: 2024 Whareroa: 2038
Supply headwinds	2023-2025: Cogeneration continues at historical levels across all plants 2025-2030 Cogeneration is reduced to 80% historical demand across all plants 2031-2035: Demand is further reduced to 60% across all plants	Glenbrook Kilns: 2035 Te Rapa: 2024 Whareroa: 2035

A.1.10 Dry year electricity demand

The hydro shortfall was estimated using historical hydro generation data from the past two decades[120]. This involved calculating the average generation for the five highest and five lowest years of hydro generation to represent wet and dry years. The difference between these two numbers was around 3.5 TWh. Based on this analysis, this study has adopted an assumption that 3 TWh of the shortfall will be met by thermal generation at an assumed frequency of 1-in-5 years. Where coal is available (which this study has assumed will be the case up to 2030) it is assumed that the thermal component is split equally between coal and gas.

For the demand model, it is assumed that the full dry year fuel supply must be available (even if not required) in every year. This is because, while it is assumed to only occur every 1-in-5 years, the unpredictable nature of dry-years means the full amount would be need to be available in any year (for example, from a gas storage field). However, for the energy security model, only 20% of the gas component of dry year cover is used as this is the amount that would be needed to be supplied

[120] https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD

from conventional or other sources to ‘recharge’ the storage. The assumptions used for each scenario are described in Table 60.

Table 60: Dry year assumptions for each scenario

Scenario	Modelling assumptions
Industry focus	▸ 2023-2040: Dry year demand from thermal sources reduces linearly from 3 TWh to 0 TWh ▸ Coal retires at the end of 2030, after which all thermal dry year cover comes from gas
Methanex exits early	▸ 2023-2030: Constant 3 TWh dry year demand from thermal sources ▸ Coal retires at the end of 2030, after which all thermal dry year cover comes from gas ▸ 2031-2050: Dry year demand from gas reduces linearly from 3 TWh to 0 TWh
Elevate electricity	▸ 2023-2030: Constant 3 TWh dry year demand from thermal sources ▸ Coal retires at the end of 2030, after which all thermal dry year cover comes from gas ▸ 2031-2050: Dry year demand from gas reduces linearly from 3 TWh to 1 TWh
Supply headwinds	▸ 2023-2030: Constant 3 TWh dry year demand from thermal sources ▸ Coal retires at the end of 2030, after which all thermal dry year cover comes from gas ▸ 2031-2050: Dry year demand from gas reduces linearly from 3 TWh to 0 TWh

A.1.11 Sectoral demand

Sectoral demand has been estimated based on the trend analysis and target reductions outlined in section 4.3 of the report.

A.2 Supply model assumptions

A.2.1 Natural gas

In order to understand natural gas supply potential and how demand could be met by supply, this study has undertaken a bottom-up approach for the supply modelling of natural gas from fields. This has taken into account published information on natural gas reserves and resources, operator information on field development, and lead times for bringing additional natural gas production on stream.

The 2P production profiles used as a base are from the MBIE reserves data published in July 2023. 2C resources are also taken from this document. No estimates have been made for prospective resources.

The modelled profiles for natural gas supply are designed to convert 2C resources to 2P to meet demand in accordance with spare production capacity. Production facility maximum and minimum capacity was taken from the MBIE published data and updated based on conversations with operators. Downtime for production facilities was assumed to be 5%.

Decline curves for each field were developed based on an analysis of the tail of existing field production where plateau production had ceased. These were assigned to new field production based on matching to an analogous field.

Upstream and midstream losses were estimated as a percentage of the total field production. The MBIE reported production data for natural gas was used as the basis. The average across a number of years was chosen based on an assessment of stable trend data over the period. In this way, early years of production and years of intense drilling were avoided as these years would have high upstream losses due to flaring during drilling campaigns and start-up of facilities. The values used in the model and period of assessment are shown in Table 61 below.

Table 61: Upstream/midstream loss factors and period of assessment

Category	Years included	Loss factor
Gas reinjected	As this depends on market conditions and is not lost to the system but is stored for later use assume that this is 0%.	0.0 %
LPG extracted	Stable trend from 2000-2004 and 2012-2022. This is based on the last main wave of large fields starting up finishing in 2012.	3.81%
Gas flared	Stable trend 1980 to 2006 and 2020 onwards. 2006-2021 elevated due to flaring of gas from Maari/Tui not connected to the gas transmission systems and start-up of key fields onshore.	0.89%
Production losses and own use	Stable trend since 1990.	2.83%
Transmission and distribution losses	Stable trend since 2000.	0.44%

In order to model different scenarios, this study has undertaken different deliverability sensitivities as described in Table 62. This has taken the form of adjusting the 2C conversion ratio and 2P deliverability in some scenarios.

The earliest start date for 2C production was taken as 2026 given the lead times on resource consents required for drilling. For some fields this was considered to be longer due to production facility constraints.

Table 62: 2C to 2P conversion and deliverability adjustments in each scenario

Scenario	Modelling assumption	Forecast 2P supply – adjustment factor	2C to 2P conversion ratio
Industry focus	Supply outlook based on MBIE's reported petroleum reserves data and 50% of 2C resource converted to 2P reserves	0%	50%
Methanex exits early	2P production profiles reduced by 30% and a reduction of 2C conversion rate to 20%	-30%	20%
Elevate electricity	Existing 2P reserves continues as per *Industry focus* scenario with a reduction of 2C conversion rate to 40%	0%	40%
Supply headwinds	2P production profiles reduced by 30% and a reduction of 2C conversion rate to 30%	-30%	30%

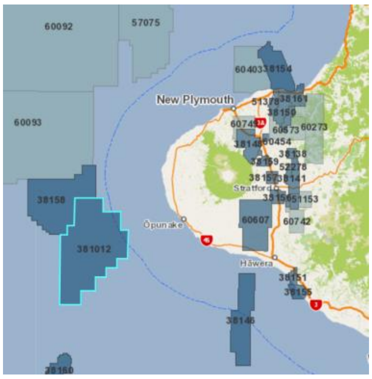
Existing field profiles

Maui

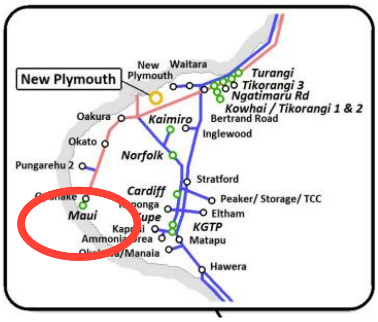
The Maui field is a large reservoir that has underpinned natural gas supply in NZ since 1979 and allowed for the development of the synthetic fuels plant at Motunui and Huntly power station. Its reservoir properties (with permeability of several Darcies) have meant it could produce flexibly for many decades. However, the late life of these assets and higher cost of running offshore facilities meant that further production potential is limited. At this point decommissioning is envisaged within the next 10 years. OMV is currently in a divestment process potentially selling its assets in NZ and Malaysia and a new operator would define investment priorities going forward. An overview of key field metrics is given in Figure 53 below[5654].

Operator	OMV
Location	Offshore
Date of First Production	1979
Permit Expiry	27/06/36
Maximum Deliverability	113 TJ/d
Minimum Deliverability	30 TJ/d
Production Types	Oil/Condensate/LPG/Gas
Emission Intensity	52.84 kt CO2e/PJ

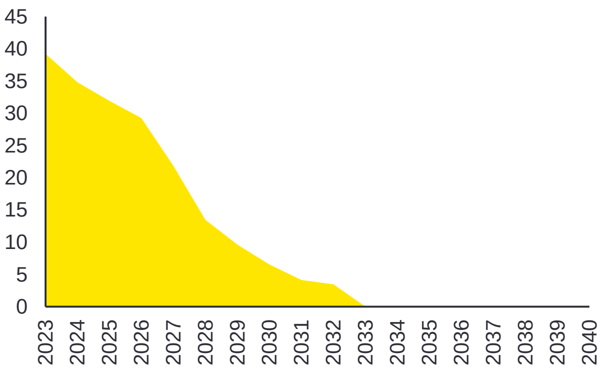
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

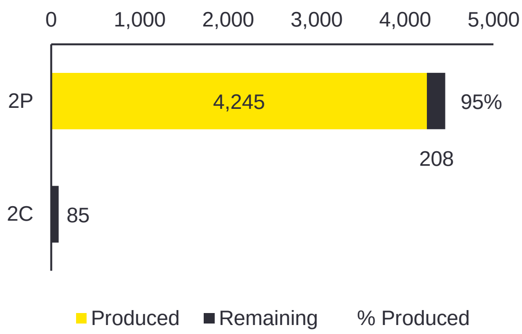


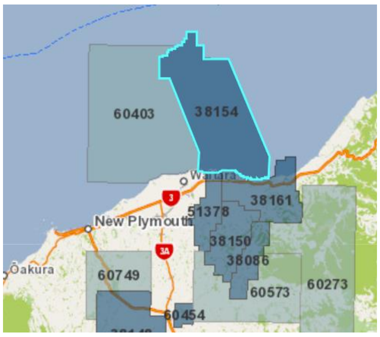
Figure 53: Maui field profile

Pohokura

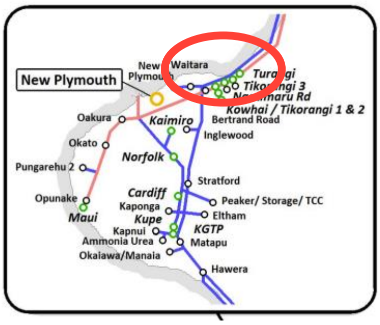
The Pohokura field came off plateau in 2020 after 14 years of production. Production is now constrained by well potential. As the production station is onshore and facilities are operated unmanned, there is flexibility to operate economically at lower fixed costs so production can continue at lower rates. Remaining reserves and resources are being developed through infill drilling of the reservoir. While production facilities are sized for 238 TJ/d, production is unlikely to reach this level again due to reservoir performance, and facilities turndown opportunities will continue through field life. OMV is preparing for drilling an additional onshore infill well in H2 2024. An overview of key field metrics is given in Figure 54 below[56].

Operator	OMV
Location	Offshore/ Onshore
Date of First Production	2006
Permit Expiry	07/10/36
Maximum Deliverability	115 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Condensate/Gas
Emissions Intensity	55.2 kt CO2e/PJ

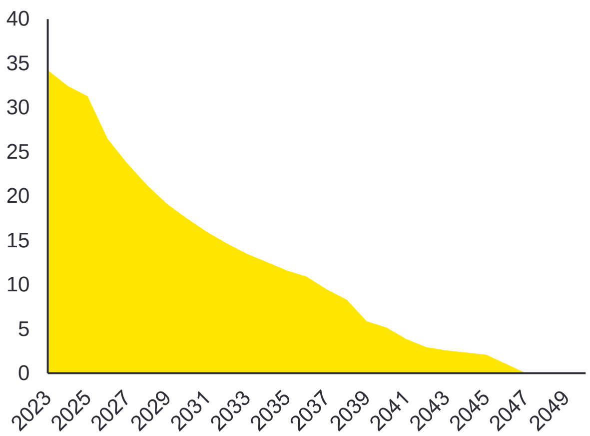
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

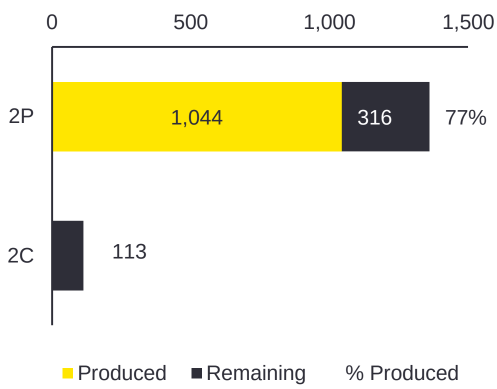


Figure 54: Pohokura field profile

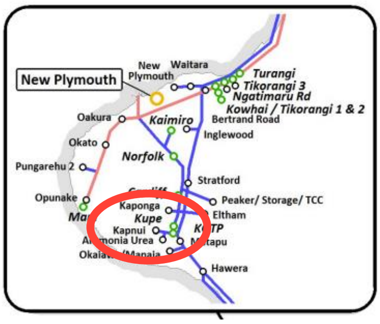
Kupe

Kupe is a mid-life asset undergoing further development drilling to maintain plateau. The inlet compression programme in 2020 maintained field deliverability and the current KS-9 (due to complete in December 2023) continues this programme. This well will secure 2P deliverability but further drilling will need to be sanctioned to secure conversion of 2C resources. This will be difficult due to consenting timeframes and the need to contract a rig for a single well programme with limited potential to share costs with other offshore operators in NZ. An overview of key field metrics is given in Figure 55 below[56].

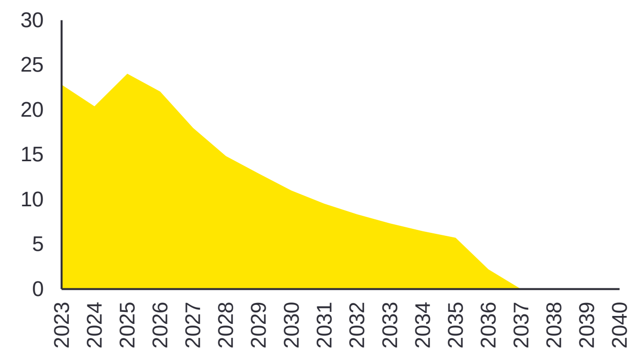
Operator	Beach Energy
Location	Offshore/ Onshore
Date of First Production	2009
Permit Expiry	26/06/31
Maximum Deliverability	77 TJ/d
Minimum Deliverability	40 TJ/d
Production Types	Oil/Condensate/LPG/Gas
Emissions Intensity	53.18 kt CO2e/PJ

Permit Location

Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

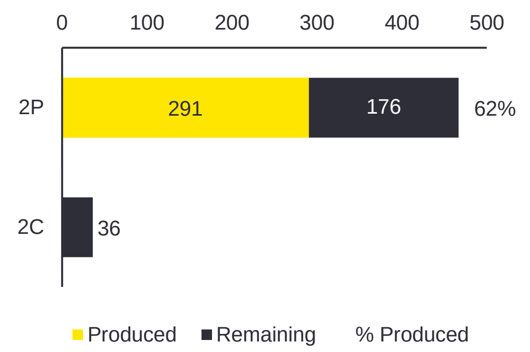


Figure 55: Kupe field reservoir profile

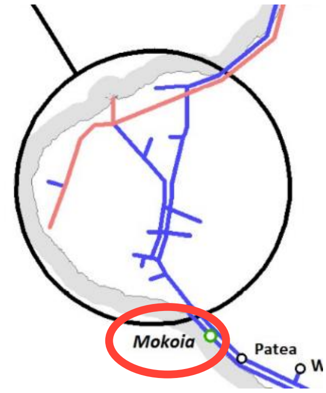
Rimu Kauri and Manutahi

The Rimu, Kauri and Manutahi fields are established oil production assets with largely depleted natural gas reserves. Produced natural gas is consumed at the field. 2C resources have been identified in the form of gas associated with a new oil play in the Kauri reservoir. This is a large development and partners would need to be identified alongside consenting and other regulatory activities. The timeframe for this project development is over 5 years but production could be exported to the grid using the existing production facilities. An overview of key field metrics is given in Figure 56 below[56].

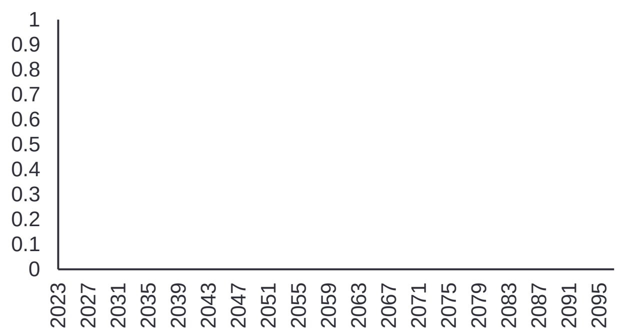
Operator	Westside
Location	Offshore/ Onshore
Date of First Production	2002
Permit Expiry	Rimu 29/01/33 Kauri/Manutahi 13/04/2035
Maximum Deliverability	10 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Oil/Condensate/LPG/Gas
Emissions Intensity	50.89 kt CO2e/PJ

Permit Location

Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

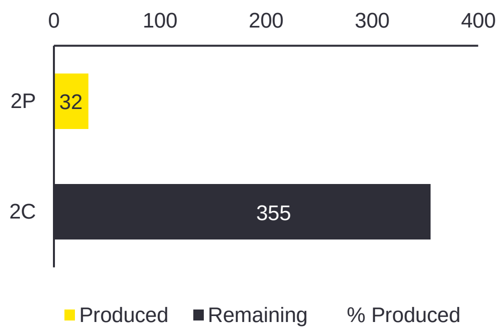


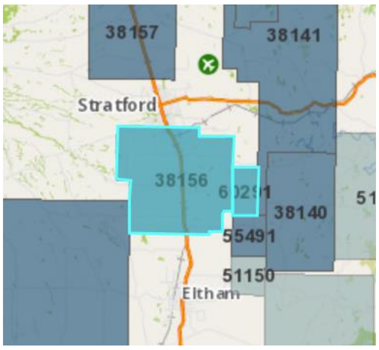
Figure 56: Rimu Kauri and Manutahi field profile

Cheal/Cardiff

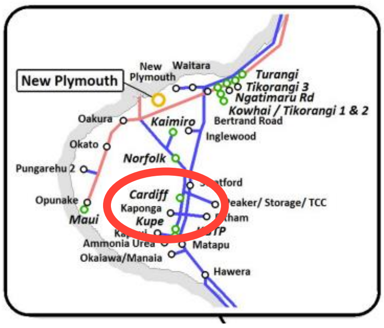
Cheal, Cardiff and Cheal East are oil producing fields onshore located near Stratford. The fields produce a small amount of natural gas which is exported to the pipeline (<0.5 TJ/d). An overview of key field metrics is given in Figure 57 below[56].

Operator	Matahio Energy
Location	Onshore
Date of First Production	2006
Permit Expiry	Cheal and Cardiff 25/07/2027 Cheal East 14/09/2037
Maximum Deliverability	2.1 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Oil/Gas
Emissions Intensity	54.47 kt CO2e/PJ

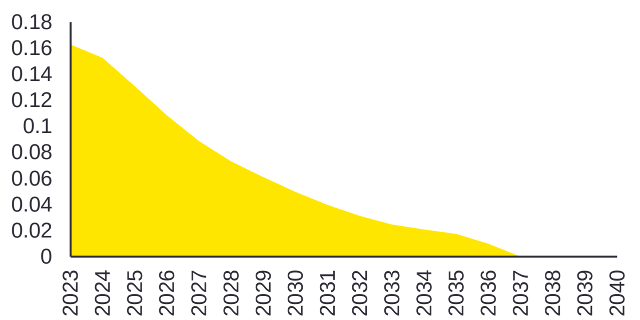
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

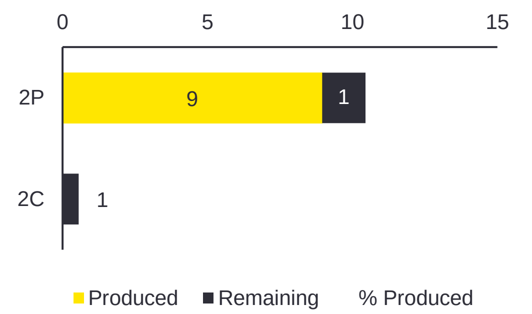


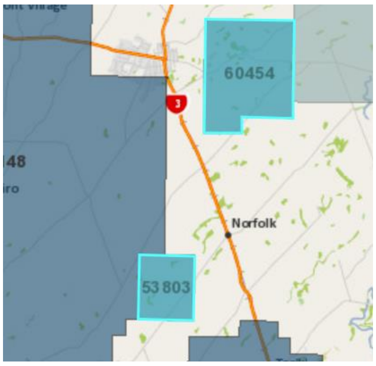
Figure 57: Cheal, Cardiff and Cheal East field profile

Sidewinder/Supplejack

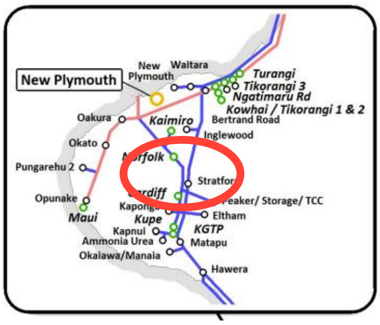
Sidewinder and Supplejack fields are oil producing fields onshore located near Inglewood. The fields produce a small amount of natural gas which is exported to the pipeline via the Norfolk mixing station (<0.5 TJ/d). The Supplejack field has been depleted and all remaining reserves/resources are attributed to the Sidewinder field. An overview of key field metrics is given in Figure 58 below[56].

Operator	Matahio Energy
Location	Onshore
Date of First Production	2006
Permit Expiry	Sidewinder 21/02/2030 Supplejack 15/10/2027
Maximum Deliverability	2.1 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Oil/Gas
Emissions Intensity	53.32 kt CO2e/PJ

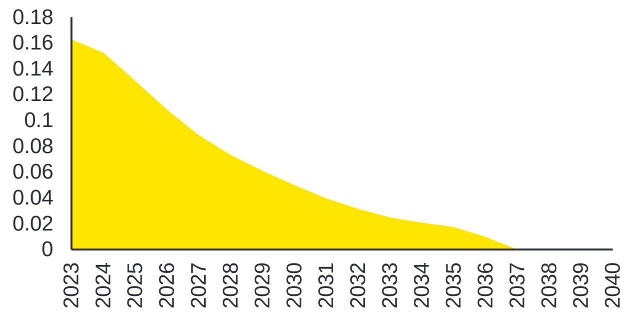
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

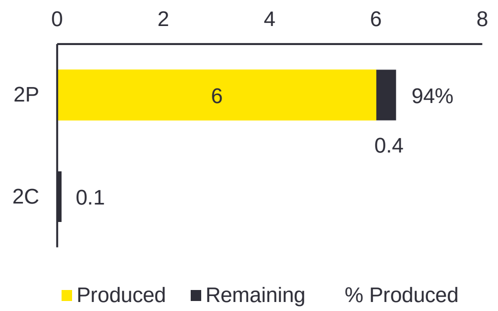


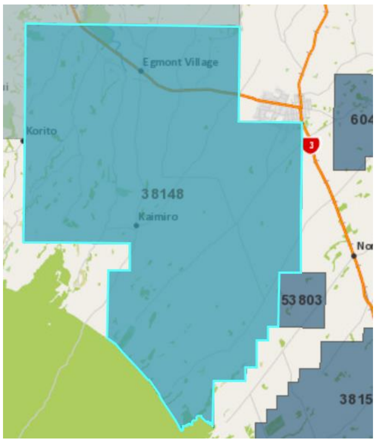
Figure 58: Sidewinder and Supplejack fields profile

Kaimiro, Ngatoro, Windsor, Goldie

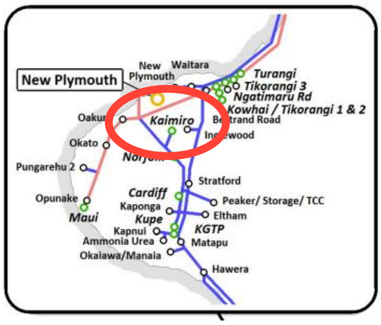
The Kaimiro mixing station provides the surface facilities for the Kaimiro, Ngatoro, Winsor and Goldie fields located near Inglewood. Natural gas production is mid-life with 35 PJ of 2P reserves remaining and 28 PJ of 2C resources. Greymouth exploration acreage to the north of the permit could provide upside for the facilities. An overview of key field metrics is given in Figure 59 below[56].

Operator	Greymouth Petroleum
Location	Onshore
Date of First Production	1998
Permit Expiry	Ngatoro, Kaimiro, Windsor and Goldie 22/12/2036
Maximum Deliverability	11 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Oil/Condensate/Gas
Emissions Intensity	54.41 kt CO2e/PJ

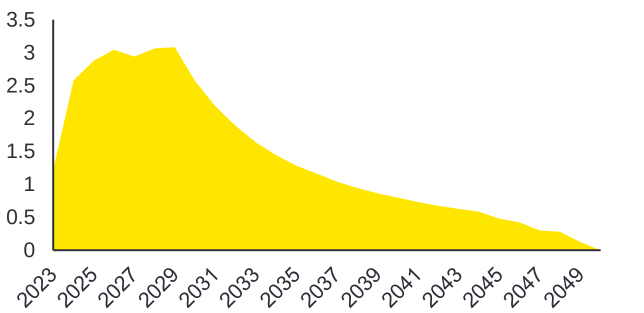
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

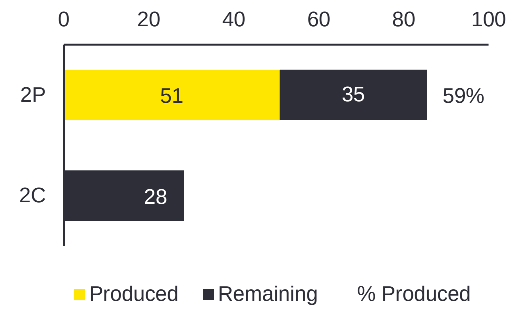


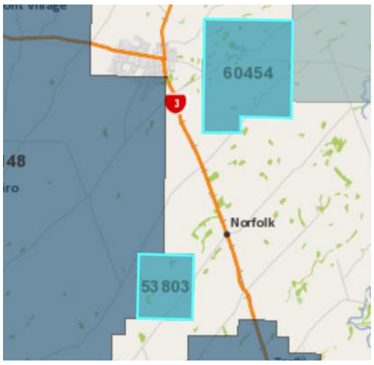
Figure 59: Kaimiro, Ngatoro, Windsor and Goldie fields profile

Radnor and Surrey

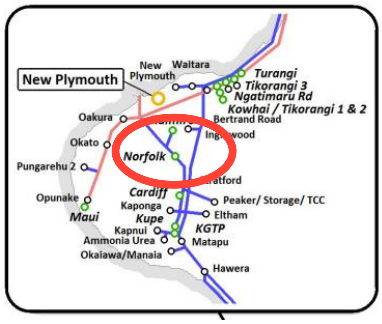
It is unclear where the Radnor and Surrey natural gas is produced. This study has assumed that this natural gas is consumed at the field and not exported to the gas pipeline as the fields are largely oil producing. An overview of key field metrics is given in Figure 60 below[56].

Operator	Greymouth Petroleum
Location	Onshore
Date of First Production	2006
Permit Expiry	Radnor 18/05/2030 Surrey 04/04/2035
Maximum Deliverability	2.1 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Oil/Condensate/Gas
Emissions Intensity	61.46 kt CO2e/PJ

Permit Location



Receipt Point Location



2P Production Profile (PJ)

Reserves and Resources (PJ)

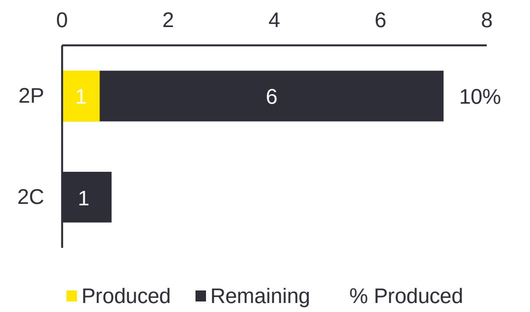
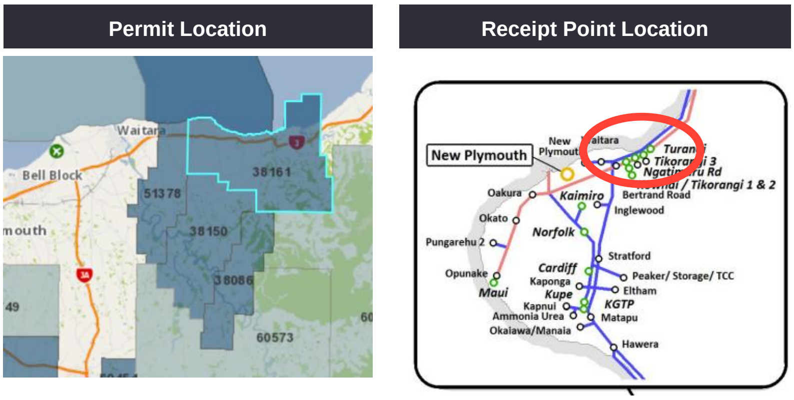


Figure 60: Radnor and Surrey field profile

Turangi, Ohanga, Onearo & Urenui

The Turangi, Ohanga, Onearo & Urenui field produces through the Turangi Mixing station near the Methanex plant at Motunui. The field has the largest remaining reserves of any field and some resources. Production is significant at up to 60 TJ/d. While operator plans are unclear, Greymouth holds exploration acreage to the west of the Pohokura permit that could be prospective and production is expected to continued until 2060. An overview of key field metrics is given in Figure 61 below[56].

Operator	Greymouth Petroleum
Location	Onshore
Date of First Production	2006
Permit Expiry	27/04/2036
Maximum Deliverability	60 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Condensate/Gas
Emissions Intensity	55.47 kt CO2e/PJ



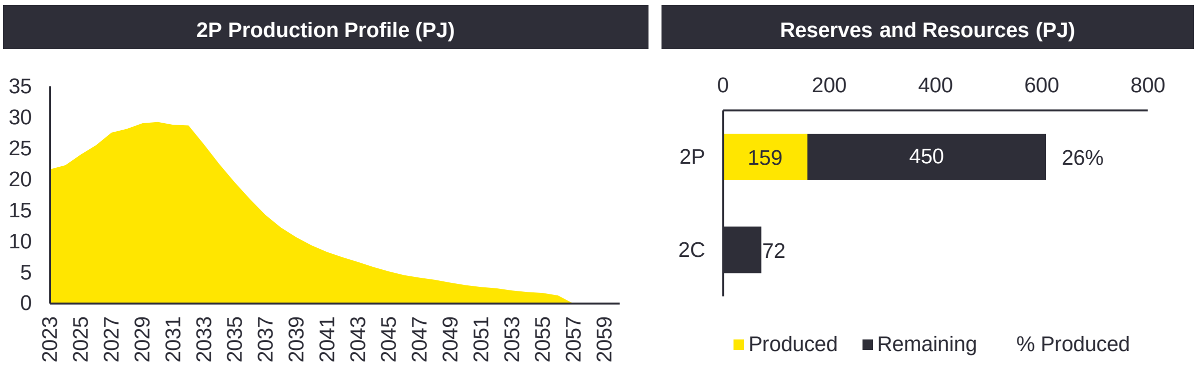


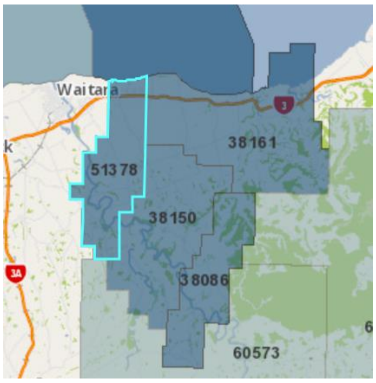
Figure 61: Turangi, Ohanga, Onearo & Urenui fields reservoir profile

Kowhai

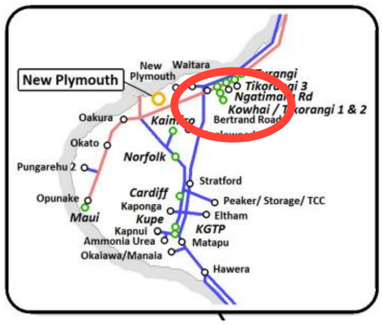
The Kowhai field produces through the Kowhai Mixing station near the Methanex plant at Motunui. While the field has the limited remaining reserves, 2C resources are similar in size to current reserves + production. Spare production capacity in the surface facilities appears to be significant at up to 30 TJ/d. While operator plans are unclear, Greymouth holds exploration acreage to the west of the Pohokura permit that could be prospective. An overview of key field metrics is given in Figure 62 below[56].

Operator	**Greymouth Petroleum**
Location	Onshore
Date of First Production	2009
Permit Expiry	01/12/2032
Maximum Deliverability	30 TJ/d
Minimum Deliverability	- TJ/d
Production Types	Condensate/Gas
Emissions Intensity	54.15 kt CO2e/PJ

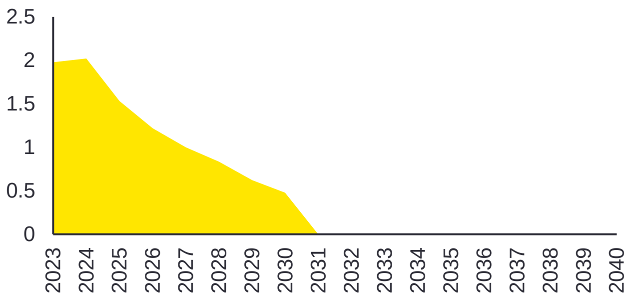
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

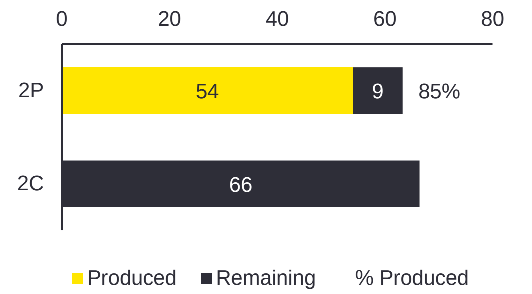


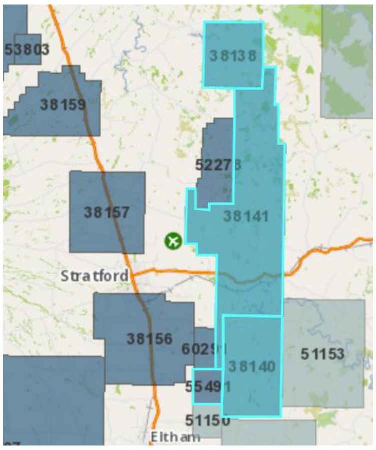
Figure 62: Kowhai field profile

TWN (Tariki, Waihapa, Ngaere, Copper Moki)

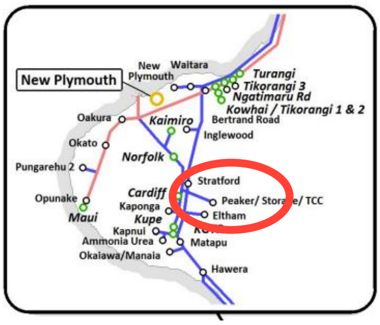
The Taraki, Waihapa, Ngaere and Copper Moki (TWN) assets are late life assets with available surface facility capacity. The Tariki structure has remaining 2P reserves of ~14 PJ that could be developed following successful drilling. An overview of key field metrics is given in Figure 63 below[56].

Operator	NZEC
Location	Onshore
Date of First Production	1990
Permit Expiry	Copper Moki 27/07/2046 Waihapa 20/06/2036 Ngaere 19/06/2036 Tariki 20/07/2026
Maximum Deliverability	Up to 25 TJ/d per well
Minimum Deliverability	- TJ/d
Production Types	Oil/Condensate/ Gas
Emissions Intensity	52.47 kt CO2e/PJ

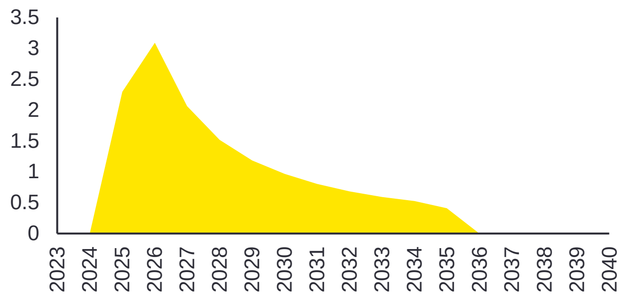
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

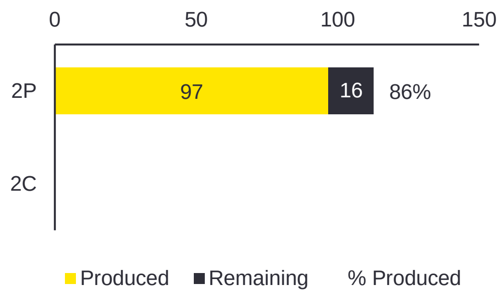


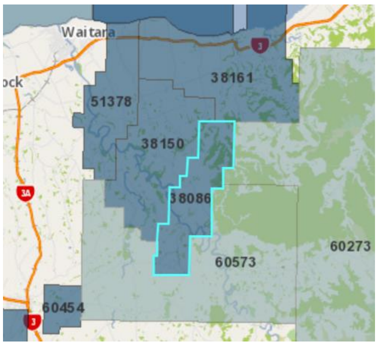
Figure 63: Tariki, Waihapa, Ngaere, Copper Moki fields profile

McKee

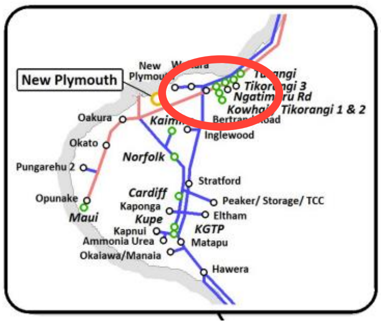
The McKee field is predominantly an oil field with associated natural gas production. The McKee peaking power station is located near at the site and takes natural gas from the McKee Mangahewa Production Station (MMPS). Despite the late-life nature of the asset, the field could produce natural gas for another 10 years from the gas cap. An overview of key field metrics is given in Figure 64 below[56].

Operator	Todd Energy
Location	Onshore
Date of First Production	1980
Permit Expiry	McKee 10/11/2025
Maximum Deliverability	25 TJ/d
Minimum Deliverability	2.5 TJ/d
Production Types	Oil/Gas
Emissions Intensity	54.38 kt CO2e/PJ

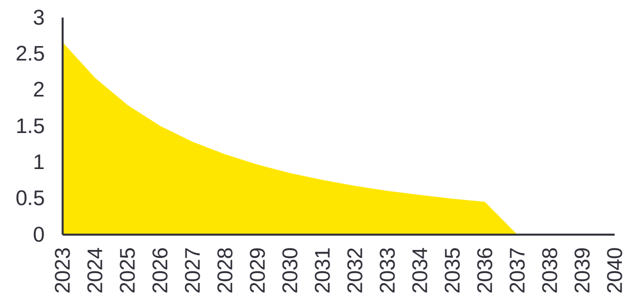
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

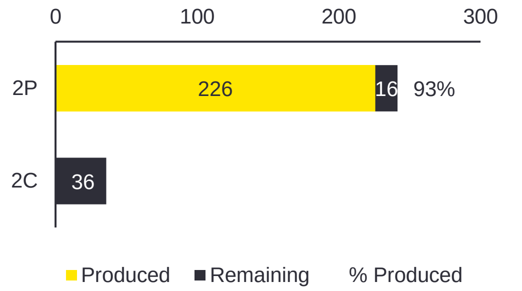


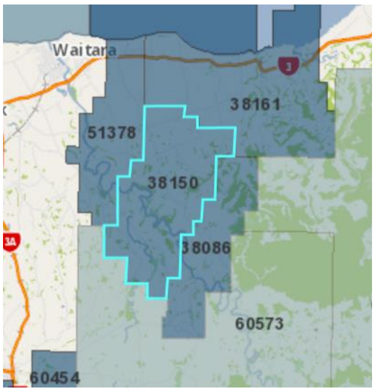
Figure 64: McKee field reservoir profile

Mangahewa

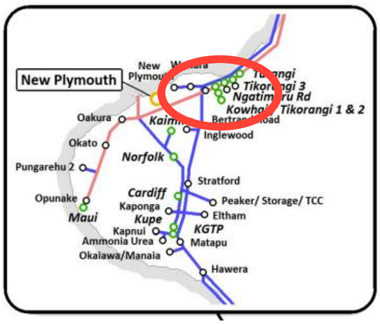
The Mangahewa field is a tight natural gas field adjacent to the McKee field but producing from a separate geologic trend and therefore a gas/condensate field rather than oil-producing. Continued drilling is required to maintain production due to the tight nature of the reservoir. Delays to the current drilling programmed will decrease production in the near term. However considerable reserves and resources remain for the field although the risk profile for this is increasing as the field enters late life and regulatory regime and costs become more onerous. An overview of key field metrics is given in Figure 60 below[56].

Operator	Todd Energy
Location	Onshore
Date of First Production	2001
Permit Expiry	McKee 10/11/2025 Mangahewa 30/04/2061
Maximum Deliverability	125 TJ/d
Minimum Deliverability	10 TJ/d
Production Types	Condensate/Gas
Emissions Intensity	54.36 kt CO_2e/PJ

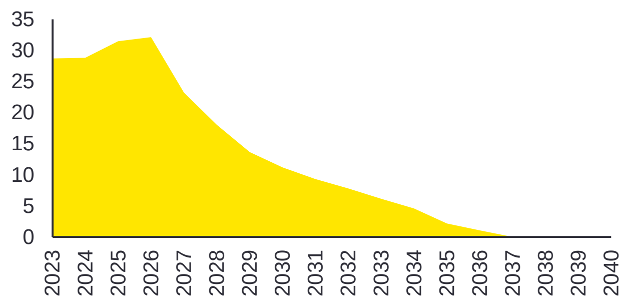
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

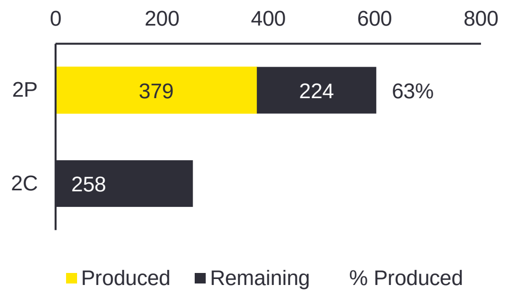


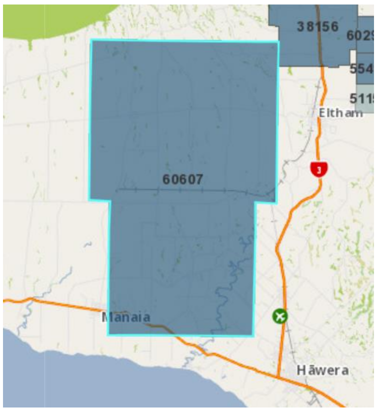
Figure 65: Mangahewa field reservoir profie

Kapuni

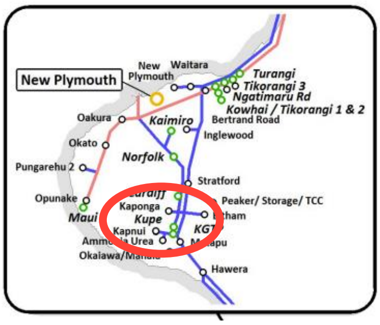
The Kapuni field is a tight natural gas field in South Taranaki. Continued drilling is required to maintain production due to the tight nature of the reservoir. Kapuni natural gas is high in CO_2 and therefore less economic due to ETS burden. A CCUS scheme would improve the economic and environmental performance of the asset. Regulatory changes enabling CCUS need to happen expeditiously to enable future development and appraisal of the Kapuni field. Considerable reserves and resources are at risk as the field enters late life and regulatory regime and costs become more onerous. An overview of key field metrics is given in Figure 66 below[56].

Operator	**Todd Energy**
Location	Onshore
Date of First Production	1970
Permit Expiry	30/10/2053
Maximum Deliverability	68.5 TJ/d
Minimum Deliverability	2.2 TJ/d
Production Types	Condensate/Gas
Emissions Intensity	53.4 kt CO2e/PJ

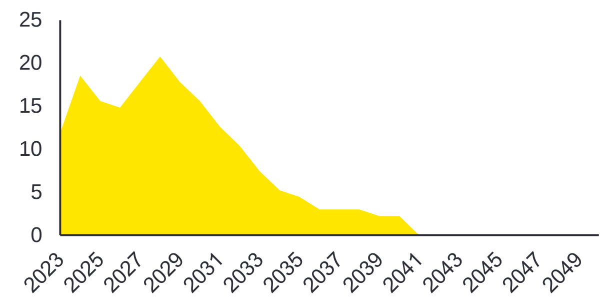
Permit Location



Receipt Point Location



2P Production Profile (PJ)



Reserves and Resources (PJ)

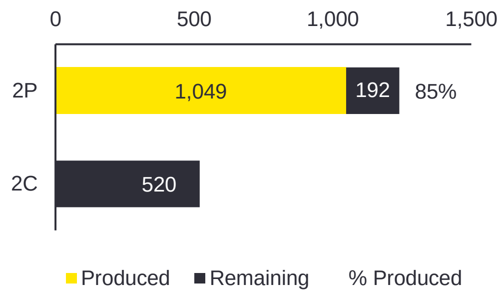


Figure 66: Kapuni field profile

Prospects

Karewa

The Karewa field is a substantial discovery but unlikely to be of a scale to be developed due to regulatory and consenting issues and its location around 50 km offshore of Raglan. Tie-back to Pohokura could be an option, but this would require a subsea pipeline in excess of 100 km. An overview of key field metrics is given in Figure 67 below[56].

Name	Karewa
Location	Offshore
2C Resources (PJ)	155
Permit Expiry	31/07/23
Wells	1 (P&A)

Permit Location

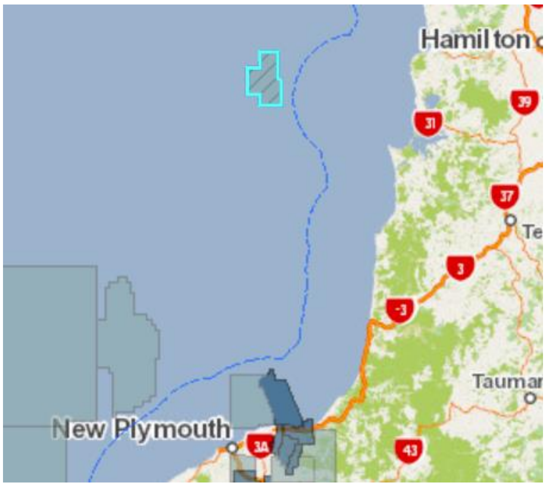


Figure 67: Karewa permit profile

A.2.2 Biogas

The key input for biogas production assumptions was the work undertaken by Beca for the Gas Transition Plan Issues Paper (Biogas Research Report)[121]. This research report surveyed the potential sources of biogas, their availability in the North Island and the cost of production.

The potential level of biogas production assessed in the Biogas Research Report is shown in Figure 68 below. Currently 4.9 PJ per year is produced at landfills, wastewater treatment plants and municipal biosolids plants. None of this is upgraded and supplied to the gas pipeline. The Ecogas Reporoa biogas plant will be the first plan to connect to the gas pipeline during 2024[122].

121 https://www.mbie.govt.nz/dmsdocument/27267-gas-transition-plan-biogas-research-report-february-2023-pdf
122 https://www.ecogas.co.nz/news/firstgas-group-and-ecogas-to-turn-biogas-into-renewable-gas-to-inject-into-gas-network

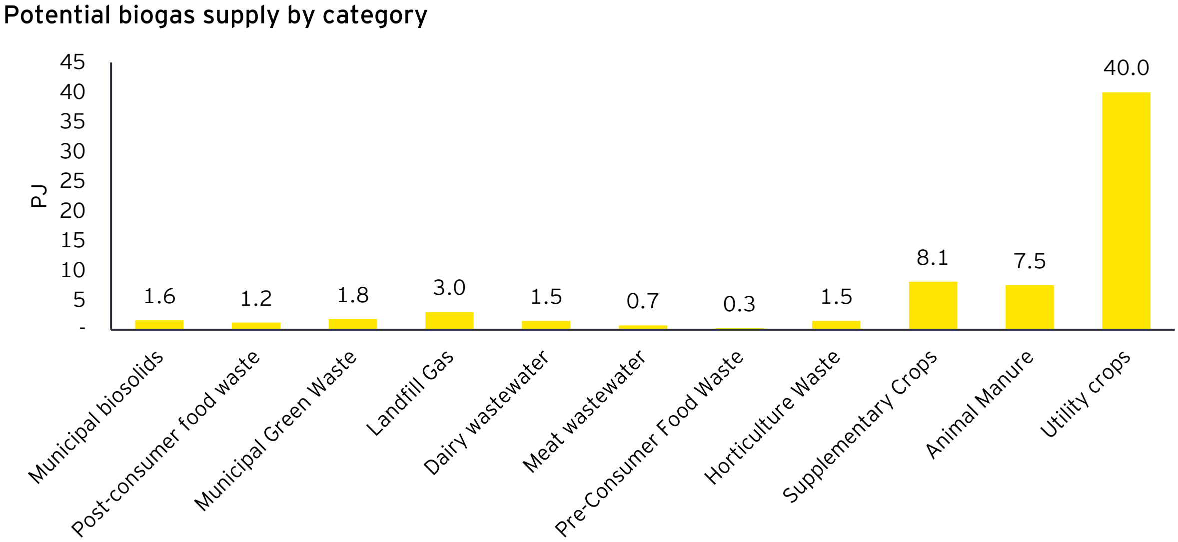


Figure 68: Biogas production potential identified in the GTP Biogas report

Only some of the biomass available for biogas production is located in the North Island and is therefore able to be injected into the gas pipeline network. Moreover, the Biogas Research Report indicated that only a certain proportion of this feedstock could practicably be produced. This study therefore moderated the total potential biogas supply by the factors shown in Table 63.

Table 63: Biogas feedstock location and practical supply factors

Biogas Feedstock Source	Practical Feedstock Supply	Proportion located in the North Island
Municipal biosolids	60%	75%
Post-consumer food waste	80%	75%
Municipal Green Waste	60%	75%
Landfill Gas	90%	75%
Dairy wastewater	80%	70%
Meat wastewater	80%	50%
Pre-Consumer Food Waste	90%	75%
Horticulture Waste	90%	60%
Supplementary Crops	90%	25%
Animal Manure	60%	70%
Utility crops	100%	100%

Biogas production, when upgraded to biomethane, can be used in natural gas appliances without changes to either the network or appliances. It is therefore considered that biogas could be a transition fuel for residential/commercial customers and, with the event of certification, the supply of biomethane to the network will be a higher value use case than the current purpose of creating heat/electricity on site. The economics of biogas are also driven by increases in cost to existing uses. As carbon prices and the cost to dispose of waste increase, the generation of biogas from organic waste becomes increasingly economic. The supply of biogas in the scenarios therefore reflects this role and is described in Table 64 below.

Table 64 Biogas supply start and end date assumptions

Scenario	Assumptions
Industry focus	Existing biogas supply is connected to the network where practicable as the value of production can be supported by certification. Biogas production plants are built to due to increased costs of waste disposal making anaerobic digestion more attractive. 30% of the biogas produced is supplied to the pipeline.
Methanex exits early	Existing biogas supply is connected to the network where practicable as the value of production can be supported by certification. Biogas production plants are built to due to increased costs of waste disposal making anaerobic digestion more attractive. 30% of the biogas produced is supplied to the pipeline.
Elevate electricity	Due to loss of natural gas supply biogas is developed at an expanded and accelerated rate to that in other scenarios. Existing biogas supply is connected to the network where practicable as the value of production can be supported by certification. Biogas production plants are built to due to increased costs of waste disposal making anaerobic digestion more attractive. 30% of the biogas produced is supplied to the pipeline.
Supply headwinds	Each initiative commences at an earlier start date and uptake is double the speed of the other scenarios in order to offset the challenges faced following a material, unforeseen event. 50% of the biogas produced is supplied to the pipeline.

The supply start date and speed of uptake of biogas supply were varied by category of feedstock supply across the different scenarios to reflect the attractiveness and practicability of feedstock development. The rates of development are outlined below in Table 65.

Table 65 Biogas supply start and end date assumptions

Scenario	Feedstock Source	Supply start date (year)	Expected term to reach biogas potential supply (number of years)
Industry focus	Municipal biosolids	2024	8
	Post-consumer food waste	2024	12
	Municipal green waste	2028	15
	Landfill gas	2024	8
	Dairy wastewater	2026	10
	Meat wastewater	2024	8
	Pre-consumer food waste	2028	12
	Horticulture waste	2028	12
	Supplementary crops	2028	12
	Animal manure	2031	15
	Utility crops	2031	15
Methanex exits early	Consistent with *Industry focus*		

Scenario	Feedstock Source	Supply start date (year)	Expected term to reach biogas potential supply (number of years)
Elevate electricity	Consistent with *Industry focus*		
Supply headwinds	Municipal biosolids	2024	4
	Post-consumer food waste	2024	6
	Municipal green waste	2026	7.5
	Landfill gas	2024	4
	Dairy wastewater	2026	5
	Meat wastewater	2024	4
	Pre-consumer food waste	2026	6
	Horticulture waste	2026	6
	Supplementary crops	2026	6
	Animal manure	2028	7.5
	Utility crops	2028	7.5

A.2.3 Hydrogen

Global trials are currently underway in various locations to integrate hydrogen supply into gas networks. This approach is regarded as a viable option for decarbonising gas usage in specific scenarios. Supply of pure green hydrogen to homes and businesses could fully decarbonise existing gas uses but would require changeout of appliances and considerable change to the gas networks due to materials and appliance compatibility[123]. Trials of 100% green hydrogen are ongoing in Scotland[124] and construction of a pure hydrogen gas grid has commenced in the Netherlands[125].

However, the context for these developments is very different to that of New Zealand. Given the relatively low uptake of hydrogen for residential/commercial space heating and the potential for electrification of these use cases in New Zealand, 100% conversion is considered unlikely. Blending of hydrogen into the existing natural gas stream is generally accepted to be feasible up to 20% (by volume – 6% on an energy basis) without requiring any changes to distribution networks or appliances[126]. As distribution networks are largely high density polyethylene (HDPE) pipelines, issues of hydrogen embrittlement of steels are not present, making blending and conversion more feasible. Testing and trials are ongoing in Australia[127][128] which has similar gas regulation to New Zealand. Trials by Firstgas are programmed for 2024[129].

123 https://h21.green/app/uploads/2022/05/H21-Leeds-City-Gate-Report.pdf
124 https://www.h100fife.co.uk/about-h100/
125 https://www.gasunie.nl/en/news/gasunie-starts-construction-of-national-hydrogen-network-in-the-netherlands
126 https://www.iee.fraunhofer.de/content/dam/iee/energiesystemtechnik/en/documents/Studies-Reports/FINAL_FraunhoferIEE_ShortStudy_H2_Blending_EU_ECF_Jan22.pdf
127 https://research.csiro.au/hyresource/atco-hydrogen-blending-project/
128 https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/111921-australias-jemena-to-test-blending-renewable-hydrogen-into-nsw-gas-network
129 https://firstgas.co.nz/green-hydrogen-cheaper/

Based on the review of available literature and in conjunction with the modelling accompanying the Gas Transition Plan Issues paper[130], this study has considered that hydrogen blending would be more feasible for distribution connected residential and commercial customers. This study assumes that this supply would be local to the distribution networks and have therefore assumed that blending would only occur in the largest population centres of Auckland and Wellington. The basis for the estimation of the potential addressable supply has been to review meter data for allocation groups 4 and 6 for Auckland and Wellington for 2022. This has been applied as a percentage across all supply. Anonymised data was sourced from the allocation agent for this purpose.

The earliest start date for blending was set at 2028 due to regulatory barriers. This study assumes that blend would be in response to natural gas supply. The assumptions are outlined in Table 66.

Table 66 Hydrogen supply assumptions by scenario

Scenario	Modelling Assumption
Industry focus	No supply of Hydrogen, assumed that hydrogen produced in New Zealand will not be connected to the gas transmission network and will not impact gas markets.
Methanex exits early	No supply of Hydrogen, assumed that hydrogen produced in New Zealand will not be connected to the gas transmission network and will not impact gas markets.
Elevate electricity	No supply of Hydrogen, assumed that hydrogen produced in New Zealand will not be connected to the gas transmission network and will not impact gas markets.
Supply headwinds	Under the *supply headwinds* scenario, hydrogen is blended into the gas network for appropriate residential and commercial use in Auckland and Wellington from 2028.

A.2.4 LNG

Research on the feasibility of LNG supply has been undertaken as part of the Gas Transition Plan Issues paper development[131]. This research considered a number of options for import terminals and the supply of gas. Based on this research this study considers the earliest supply date for LNG import would be 2030 due to the considerable infrastructure required and the commercial chain that would need to be developed to support import. The cargo size for LNG has been taken as 4 PJ. As LNG is assumed in this study to be a supply of last resort, cargoes are imported to meet demand. This study has not considered the lead times in buying cargoes as modelling is on an annual basis. The assumptions per scenario are given in Table 67.

Table 67: LNG supply model assumptions by scenario

Scenario	Modelling assumption
Industry focus	LNG is imported to meet demand from 2030.
Methanex exits early	No LNG Is imported as Methanex supply is released to the market.
Elevate electricity	LNG is imported to meet demand from 2030.
Supply headwinds	LNG is imported to meet demand from 2030.

[130] https://www.mbie.govt.nz/dmsdocument/27266-new-zealand-hydrogen-scenarios-and-the-future-of-gas-september-2022.pdf
[131] https://www.mbie.govt.nz/dmsdocument/27262-lng-import-and-options-to-increase-indigenous-gas-market-capacity-and-flexibility-in-new-zealand-march-2023-pdf

A.3 Emissions model assumptions

A.3.1 Upstream emissions

Upstream emissions are emissions released during the exploration and production of natural gas. This includes activities like drilling and the immediate processing of natural gas to make it suitable for transportation or further refining. There are two main sources of emissions:

- Fugitive emissions from flaring and venting of gas[132]
- Combustion of gas during gas processing

Emissions factors have been determined based on analysis of the MBIE reported data for gas production and emissions. Similar to the production losses in Table 61, the average across a number of years was chosen based on an assessment of stable trend data over the period. In this way, early years of production and years of intense drilling were avoided as these years would have high upstream losses due to flaring during drilling campaigns and start-up of facilities. The Fugitive emission factor used in the model and period of assessment is shown in Table 68 below. Own use is taken from the analysis in Table 61 and the emissions intensity for this combustion is as per industrial stationary combustion (see downstream emissions section).

Table 68: Upstream fugitive emissions factor and period of assessment

Category	Years included	Emissions factor (kt CO_2e/PJ)
Production fugitive emissions	Stable trend from 1990-2002 and 2013-2022. This is based on the last main wave of large fields starting up finishing in 2012. Data used from 2013	3.34

There is upstream CCUS potential in the form of associated gas capture and gas reinjection, with gas reinjection being historically utilised at the Kapuni gas fields. This study has not modelled any CCUS uptake in the scenarios due to the regulatory uncertainty around the adoption and uptake of CCUS in NZ. However, a limited level of CCUS has been presented as a sensitivity to the *Industry focus* scenario, the details of which are discussed in the main body of the report.

A.3.2 Midstream emissions

Midstream emissions refer to emissions released during the transportation of natural gas before it reaches the end-user. Emissions are generated from the following key sources:

- Fugitive emissions from pipeline leakage
- Combustion of gas during gas compression

[132] In the National Greenhouse Gas Inventory flaring is reported as a fugitive emissions even though the gas is burnt during flaring. This grouping has been retained for consistency.

This study has based the assessment of fugitive emissions on the methodology specified in the National Greenhouse Gas (GHG) Inventory[133]. The Inventory uses an emission factor of 55.6 kt CO_2e/PJ and a leakage rate of 0.35% of gas entering the pipeline. To confirm this factor an analysis of historical data was performed using the MBIE gas statistics as per the analysis outlined in the calculation of production losses above. This analysis yielded a midstream fugitive emissions factor of 0.50% as shown in Table 61.

Combustion emissions from the pipeline are generated based on the pipeline operating conditions. This study has therefore analysed historic emissions from pipeline transportation reported in the National Greenhouse Gas Inventory to understand the trend. The resulting midstream combustion emissions factor is

Table 69: Midstream combustion emissions factor and period of assessment.

Category	Years included	Emissions factor (kt CO_2e/PJ)
Midstream combustion emissions	This shows a discontinuity in the data prior to 2004 and changes in compressor usage following 2016. The calculation of the emissions factor is therefore based on production and emissions data from 2004 onwards.	0.21

A.3.3 Downstream emissions

A.3.3.1 Stationary combustion emissions

Stationary combustion emissions are released during the burning of fuels in fixed equipment, ranging from power plants to residential furnaces. When natural gas undergoes combustion, it releases a suite of emissions including carbon dioxide, methane, and nitrous oxide. The stationary combustion emissions of natural gas are nearly identical between industrial, commercial, residential and electricity generating users. With the only difference being the amount of methane released for commercial and residential users (0.11 kg CH4/GJ) compared to the others (0.02 kg CH4/GJ). The values for most stationary combustion have been taken from Ministry for the Environment guidance on emissions calculation guidance[134]. Methanex and Ballance have different stationary combustion emission factors than other industrial users due to the complexities of their processes. These emissions factors have been inferred from MBIE reporting data on Methanex and Ballance emissions. The assumptions used as the stationary combustion emission factors are shown below in Table 70.

Table 70: Stationary combustion emission factor per sub-sector

Emission sub-sector	Emission Factor (kt CO_2e/PJ)
Industrial	54.05
Commercial	54.14
Residential	51.14
Baseload	54.05
Peaking	54.05
Cogeneration	54.05

[133] https://environment.govt.nz/assets/publications/climate-change/New-Zealands-Greenhouse-Gas-Inventory-1990-2021-Chapters-1-15.pdf
[134] https://environment.govt.nz/assets/publications/Measuring-emissions-guidance-August-2022/Detailed-guide-PDF-Measuring-emissions-guidance-August-2022.pdf

Emission sub-sector	Emission Factor (kt CO_2e/PJ)
Probability Weighted Dry Year Electricity	54.05
Motonui	50.19
Waitara Valley	50.19
Ballance	44.76

The entirety of the natural gas demand consumed by industrial, commercial, residential, and electricity generation users is dedicated to stationary combustion. In contrast, Methanex and Ballance allocate only 40% and 50% of their total natural gas demand respectively[135].

The potential for deploying CCUS technologies is more promising in the context of stationary combustion emissions. This viability is attributed to several factors, such as the high concentrations of CO_2 present, the consistency of the emission source, and more mature technologies which are moving closer towards commercial viability. However, this study has not modelled any CCUS uptake for stationary combustion emissions for the same reasons listed in A.3.1.

A.3.3.2 Process Emissions

Methanex and Ballance also use natural gas as a feedstock to further process and refine into their finished products, methanol, and urea respectively. This accounts for a significant portion of the natural gas demand for both Methanex and Ballance, representing 60% of Methanex's total natural gas consumption and 50% of Ballance's[136].

As per the combustion emissions for Methanex and Balance, the process emissions per unit of gas consumed have been estimated based on analysis of MBIE's gas and emissions reporting data. The resulting emissions factors are shown in Table 71 below.

Table 71: Methanex and Ballance process emissions factor

Emission sub-sector	Emission Factor (kt CO_2e/PJ)
Methanex	2.34
Ballance	5.49

There is currently limited potential for CCUS in capturing downstream petrochemical process emissions and CCUS has not been modelled.

A.4 Price outcomes model assumptions

A.4.1 Natural gas price

To project the natural gas prices within the model, this study initially identified a baseline natural gas price and varied this to reflect potential changes in cost of supply due to the relative scale of the industry. This is based on the premise that gas supply is a high fixed cost industry and

[135] These stationary combustion percentages have been inferred from an analysis of MBIE's historical gas demand data combined with consultation with industry.

[136] The feedstock demand % is the residual proportion after the deducting the combustion demand % (i.e Methanex process demand = 100% - 40% (stationary combustion)

therefore material reduction in gas price will increase unit gas price. This analysis was based on a commodity cost and excluded carbon. The variable cost component of the price was varied based on gas production while the fixed cost component was varied based on the operation of major production installation. As 2C resources are currently not commercial, the variable cost component for these resources was increased by a factor of 2 to allow for increased cost of development and therefore supply. The parameters in this analysis are outlined in Table 72.

Table 72: Natural gas price components

Category	Comments	Parameter
Fixed cost assumption	Consultation with upstream operators	64%
Variable cost assumption for 2P	Consultation with upstream operators	36%
Weighting for 2C resource production	Consultation with upstream operators - allowance for higher cost	200%
Reference gas price (excluding carbon)	Assessment of MBIE gas price data - assumed to be commodity price only.	10.00 $/GJ

A.4.2 Biogas price

Biogas supply costs have been taken from the analysis undertaken in the Biogas report prepared to support the Gas Transition Plan. The model calculates the weighted average cost of supply across the sources of biogas required to supply the required volume of biogas. The cost associated with different biogas supply sources varies based on tranches, shown below in Table 73.

Table 73: Biogas source price stack[137]

	Biogas Supply Source Cost ($/GJ)				
Source	0%-40%	40%-60%	60%-80%	80%-90%	90%-100%
Municipal biosolids	15.00	20.00	20.00	20.00	20.00
Post-consumer food waste	30.00	40.00	50.00	50.00	50.00
Municipal Green Waste	70.00	80.00	80.00	80.00	80.00
Landfill Gas	10.00	15.00	20.00	30.00	30.00
Dairy wastewater	20.00	25.00	40.00	40.00	40.00
Meat wastewater	10.00	25.00	40.00	40.00	40.00
Pre-Consumer Food Waste	30.00	40.00	50.00	60.00	60.00
Horticulture Waste	30.00	40.00	50.00	60.00	60.00
Supplementary Crops	35.00	45.00	60.00	60.00	60.00

137 https://www.mbie.govt.nz/dmsdocument/27267-gas-transition-plan-biogas-research-report-february-2023-pdf

	Biogas Supply Source Cost ($/GJ)				
Source	0%-40%	40%-60%	60%-80%	80%-90%	90%-100%
Animal Manure	70.00	80.00	80.00	80.00	80.00
Utility crops	65.00	65.00	65.00	65.00	65.00

A.4.3 LNG price

LNG pricing has been based on the research undertaken on LNG to support the Gas Transition Plan. This considers the commodity cost of LNG, the variable cost of importing LNG and the annual fixed cost of operating LNG import facilities. These costs are outlined in Table 74.

Table 74: LNG cost components[138]

Category	Cost component
Commodity	$14.00 / GJ
Variable Costs	$3.84 / GJ
Fixed Costs	$56,500,000 / yr

A.4.4 Carbon impost

To determine the carbon impost for the various gas types, the emission intensities specific to each gas were identified and multiplied by the carbon price applicable for the given year. The emission intensity for biogas was derived using a weighted average approach to reflect the different emission factors of biogas produced from anaerobic digestion and landfill gas, contingent upon the specific supply parameters of each scenario. The different emission intensities are outlined in Table 75. The carbon price used was the Demonstration Path carbon price developed by the Climate Change Commission[139].

Table 75: Emission Intensity

Category	Source	Emissions factor (kg CO_2e/GJ)
Natural Gas	Average gas emissions intensity provided by GIC	55.73
LNG	Average gas emissions intensity provided by GIC	55.73
Biogas from Anaerobic Digestion	Biogas Research Report supporting the Gas Transition Plan	19.00
Biogas from Landfill Gas	Biogas Research Report supporting the Gas Transition Plan	10.00

138 https://www.mbie.govt.nz/dmsdocument/27262-lng-import-and-options-to-increase-indigenous-gas-market-capacity-and-flexibility-in-new-zealand-march-2023-pdf

139 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.climatecommission.govt.nz%2Fpublic%2FInaia-tonu-nei-a-low-emissions-future-for-Aotearoa%2FModelling-files%2FTiwai-point-sensitivity-dataset-final-advice-2021.xlsx

A.4.5 Residential user costs

This model is tailored to calculate the gas expenses incurred by a residential user. To achieve this, it aggregates all fixed and variable costs relevant to residential consumption. The fixed costs include distribution fees, metering charges, and energy retailer margins. Variable costs comprise of distribution and transmission expenses, regulatory levies, and charges for unaccounted for gas. The price that a residential user pays for the price of gas is represented by the weighted average of all gas prices entering the pipeline, as determined by the gas pricing model. The inputs to this model were supplied by a stakeholder to the GIC and some assumptions are confidential. The assumptions are therefore not provided in this document.

A.5 Conversion factors

The following table outlines the conversion factors used in this study.

Table 76: Conversion Factors

Original Unit	Target Unit	Conversion Factor
PJ	TJ	1,000
PJ	GJ	1,000,000
TWh	GWh	1,000
kg	MWh	30.03[140]
MWh	PJ	277,788
NZD	USD	0.65

[140] Used to convert the cost of hydrogen from $/kg to $/MWh to $/PJ

Appendix B Modelling methodology and limitations

The purpose of this appendix is to provide an outline of the modelling methodology underlying the models developed by EY. This appendix includes an overview of the modelling scope and approach to contextualize and clarify the rationale behind the assumptions.

B.1 Demand model methodology

The demand model methodologies for petrochemical demand and sectoral demand is explained in the main body of the report. Therefore only the electricity generation section of natural gas demand will explained here.

B.1.1 Natural gas demand for electricity generation

The modelling methodology is summarised in the diagram below.

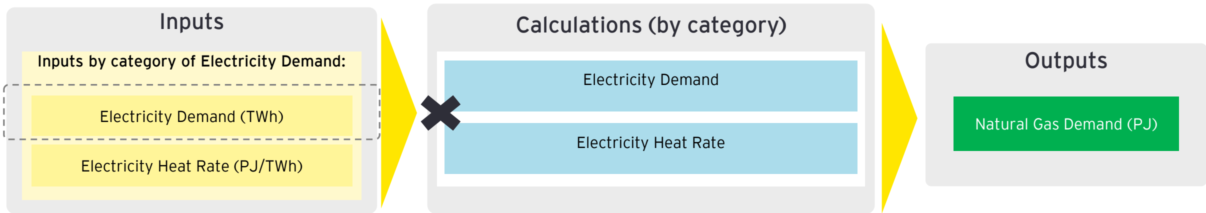


Figure 69: Natural gas demand for electricity generation model methodology

The electricity demand categories are baseload, peaking, cogeneration, and dry year cover.

Key inputs in the above methodology include the following:

- Electricity demand - the quantity of forecast electricity generation required from each of the demand categories based on the specific demand parameters on the scenario.
- Electricity heat rate - the amount of natural gas required to produce 1 TWh of electricity, based on the MBIE thermal generation stack and an analysis of historical data.

The key calculations in this model are outlined in Table 77 below.

Table 77: Natural gas demand for electricity generation calculations

Category	Calculation approach	Source for inputs
Baseload (PJ)	= (Baseload Electricity Generation) * (Baseload Heat Rate)	*Baseload Electricity Generation:* CCC & Transpower forecasts *Baseload Heat Rate*: MBIE Thermal Stack
Peaking (PJ)	= (Peaking Electricity Generation) * (Peaking Heat Rate)	*Peaking Electricity Generation:* Analysis of historical data from Electricity Authority (EA) *Peaking Heat Rate:* MBIE Thermal Stack
Cogeneration (PJ)	= (Cogeneration Electricity Generation) * (Cogeneration Heat Rate)	*Cogeneration Electricity Generation*: Analysis of historical data from EA *Cogeneration Heat Rate*: Analysis of MBIE electricity/gas statistics
Dry Year Demand (PJ)	= (Dry Year Generation Demand) * (Dry Year Heat Rate)	*Dry Year Generation Demand:* Analysis of historical data from EA *Dry Year Heat Rate*: EY Assumption

The following key assumptions and limitations are highlighted with regard to the above methodology:

- This model has assumed a heat rate assumption for each electricity category, but the individual plants may have different heat rates (for example the Stratford peaking units have a heat rate of 8.9 GJ/GWh, but Huntly Unit 6 has a heat rate of 10.53 GJ/GWh).

In summary, the total natural gas demand for the purpose of electricity generation consists of baseload, peaking, cogeneration, and dry year demand. The natural gas demand is calculated by multiplying the electricity generation demand by the corresponding heat rate, and then summing together the natural gas demand of each category to get the total natural gas demand for electricity generation.

B.2 Supply model methodology

In order to understand natural gas supply potential and how demand could be met by supply, this study has undertaken a bottom-up approach to supply modelling of gas from fields. This has taken into account published information on gas reserves and resources, operator information on field development and lead times for bringing additional gas production on stream. From this information this study has produced an 'unconstrained gas supply profile'. The demand profile, built up in the previous section, has then been used to modify this supply profile to match supply and demand and understand what supply would need to be from alternative sources (biomethane, hydrogen and LNG) if demand were to be met in full. This has formed the supply outlook for each of the scenarios.

This section outlines the methodology used to develop the supply profiles for the following sources of gas supply:

- Natural gas
- Biogas
- Hydrogen
- LNG

The modelling approach for each source of gas is discussed in the following sections.

B.2.1 Natural gas

The modelling methodology is summarised in the diagram below.

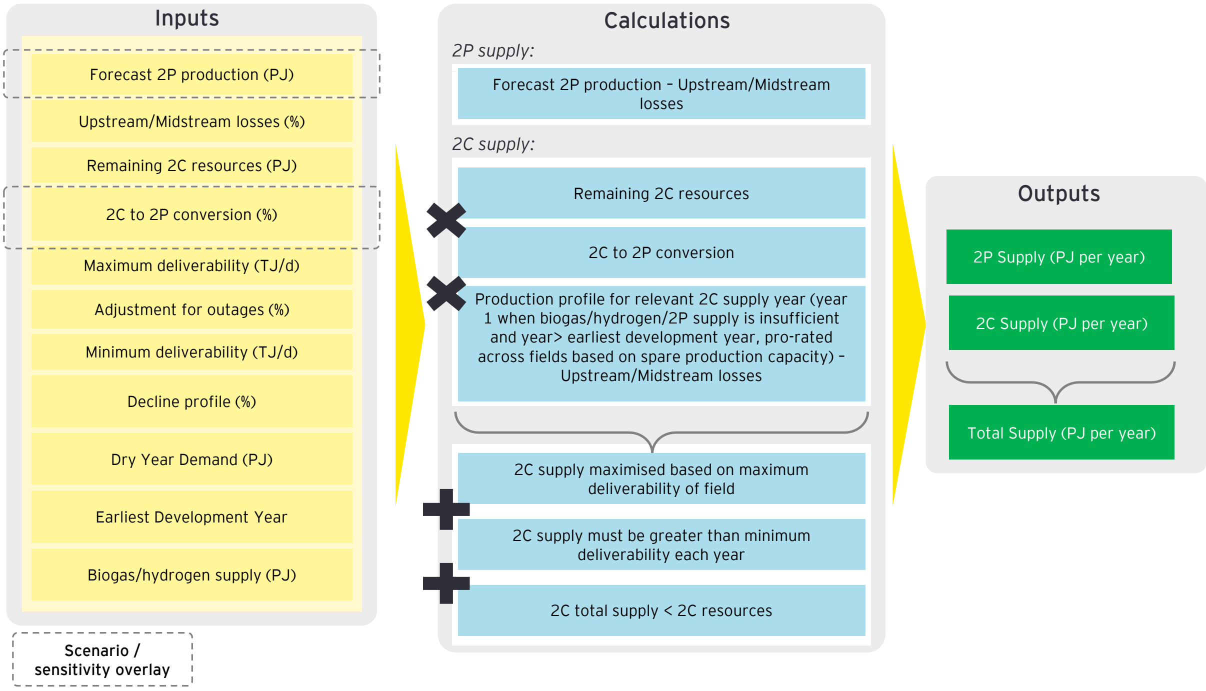


Figure 70: Natural gas supply forecast methodology

Key inputs in the above methodology include the following:

- Forecast 2P supply, representing the forecast gas production at each field provided to MBIE by the field operator.
- Remaining 2P reserves, representing the proven plus probable resources at each field. These reserves have a 50% certainty of being produced.
- Remaining 2C resources, representing the resources estimated at a particular time to be potentially recoverable, but which are not commercially recoverable at this time.
- 2C to 2P conversion, representing a view on the probability of resources being developed based on consultation with operators.
- Maximum and minimum deliverability at each field, per year.
- Adjustment for outages, representing a downward adjustment to gas production as a result of outages at each field.
- Production profile, representing the supply in each year as a percentage of total supply over the forecast period.

The key calculations in this model are outlined in Table 78 below.

Table 78: Natural gas 2P reserve and 2C resource supply calculations

Component	Calculation approach	Sources for inputs
2P Production	= IF(SUM(forecast 2P production for all prior years) > (remaining 2P reserves), 0, forecast 2P production)	*Forecast 2P production for all prior years:* sum of all prior years in the 2P production timeseries
Natural gas demand to be supplied	= (Dry Year Demand) – (Scenario Other Supply – Biogas, Hydrogen, 2P Production)	*Dry Year Demand:* Demand model
		Scenario Other Supply: 2P Production from above. Biogas and Hydrogen from supply model.
Pro-rated 2C Demand	= MIN (spare production capacity, share of Natural gas demand to be supplied based on spare production capacity) as long as the year of production is >earliest development year	*Natural gas demand to be produced:* discussed above
		Spare production capacity: max field deliverability – 2P Production
		Earliest Development Year: from operator conversations
2C Production	= MIN(Pro-rated 2C Demand, Remaining 2C Resources)	*Pro-rated 2C demand:* discussed above
		Remaining 2C Resources: sum of prior years' 2C production
Total Production	= (2P Production) + (2C Production)	*2P supply:* MBIE data, discussions with suppliers and varied across scenarios
		2C supply: discussed above
Total Supply	= (2P Production) + (2C Production) x (1- Upstream/Midstream losses)	*Upstream/midstream losses: estimated average values based on trends in MBIE production reporting data.*

In summary, supply of natural gas is equal to forecast 2P Production plus 2C Production subject to maximum deliverability of each field, spare production capacity available at the field, remaining resources and fulfilling demand after biogas and hydrogen production.

The following key assumptions and limitations are highlighted with regard to the above methodology:

- Some contact has been made with the operators of each field, in order to verify key information obtained from MBIE regarding remaining reserves and future production profile. However, this has not been extensive or comprehensive consultation.

- The above methodology is designed to describe aggregate production of gas across all field to meet demand. It does not reflect operator plans for field development.

B.2.2 Biogas

The modelling methodology is summarised in Figure 71 below.

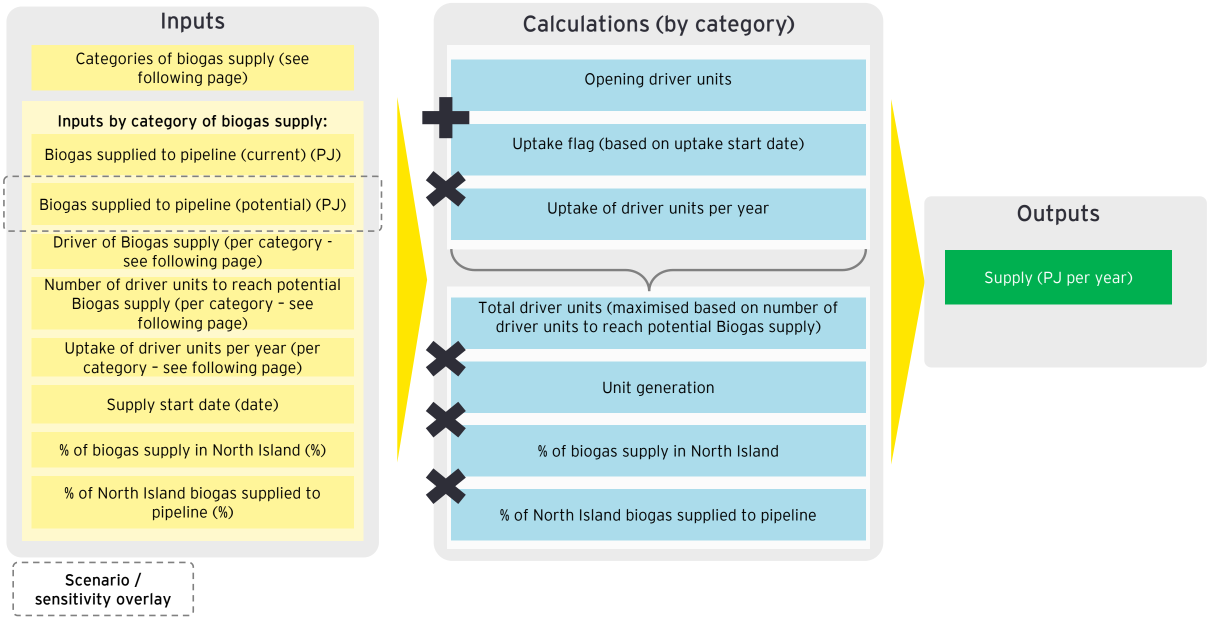


Figure 71: Biogas supply forecast methodology

Key inputs in the above methodology include the following:

- Categories of biogas supply based on the GTP Biogas Research Report and the associated driver of supply by category.

The biogas production sources and drivers are outlined in Table 79 below.

Table 79: Biogas production sources and drivers

Category	Driver
Municipal biosolids	Municipal wastewater treatment plants (WWTPs) with AD (#)
Post-consumer food waste	Segregated organic waste (T/year)
Municipal green waste	Commercial green waste AD plants (#)
Landfill gas	Landfills with gas capture (#)
Dairy wastewater	Dairy WWTPs with AD (#)
Meat wastewater	Meat WWTPs with AD (#)
Pre-consumer food waste	Diverted waste (T/year)
Horticulture waste	Diverted waste (T/year)
Supplementary crops	Grass growth land area (ha)
Animal manure	Solids recovered (T/year)
Utility crops	Productive grass area (ha)

Biogas production is based on the following inputs and methodology:

- Number of driver units to reach potential Biogas supply by category, based on the GTP Research Report. For example, the GTP Research Report implies that 22 municipal WWTPs are required to supply 1.6 PJ of biogas per year.

- Uptake of driver units per year, based on the expected term to reach the potential biogas supply by category. For example, the *Industry focus* scenario assumes that the potential supply from Municipal Biosolids is reached 8 years after supply commences, implying approximately 3 WWTPs per year over this time.

- Supply start date, representing the year in which supply of biogas will commence by category.

- Percentage of biogas supplied in North Island by category, based on assumptions outlined on page 33 of the GTP.

The key calculations are summarised in the Table 80.

Table 80: Biogas production calculations

Component	Calculation approach	Sources for inputs
Uptake flag	=IF(year > uptake start date, 1 , 0)	*Uptake start date:* based on price table on page 33 of GTP Biogas Research Report and varied across scenarios
Total driver units (maximised based on number of driver units to reach biogas potential)	=MIN((uptake flag) x ((opening driver units) + (uptake of driver units per year))), number of driver units to reach potential biogas supply)	*Uptake flag:* discussed above
		Opening driver units: zero in 2023, given that there is no current Biogas supply into the pipeline
		Uptake of driver units per year: based on price table on page 33 of GTP Biogas Research Report and varied across scenarios
		Number of driver units to reach potential Biogas supply: Based on GTP Biogas Research Report
Unit generation	= (biogas supplied to pipeline (potential)) / (number of driver units to reach potential biogas supply)	*Biogas supplied to pipeline (potential):* GTP Biogas Research Report, page 33
		Number of driver units to reach potential Biogas supply: discussed above
Total future generation	= (total driver units) x (unit generation)	*Total driver units:* discussed above
		Unit generation: discussed above
Total supply	= (total future generation) x (% of biogas supply in North Island) x (% of North Island biogas supplied to pipeline)	*Total future generation:* discussed above
		% of biogas supply in North Island: GTP Biogas Research Report, *page 33*
		% of North Island biogas supplied to pipeline: 100%, EY assumption

In summary, Biogas supply is a function of the speed of uptake of each supply category's key driver.

The following key assumptions and limitations are highlighted with regard to the above methodology:

- Uptake of each category's driver is assumed to be straight-line. This does not allow for any efficiencies as the number of driver units increase.
- The high-level calculation of biogas supply per driver unit is based on the potential biogas supply of each category and the number of driver units to reach this potential. This represents a simplified approach for modelling purposes and may not be the case in reality. For example, in the municipal biosolids category, larger municipal WWTPs may lead to more supply than smaller plants.
- A significant proportion of these inputs are sourced from the GTP Biogas Research Report.

B.2.3 Hydrogen

The modelling methodology is summarised in the diagram below.

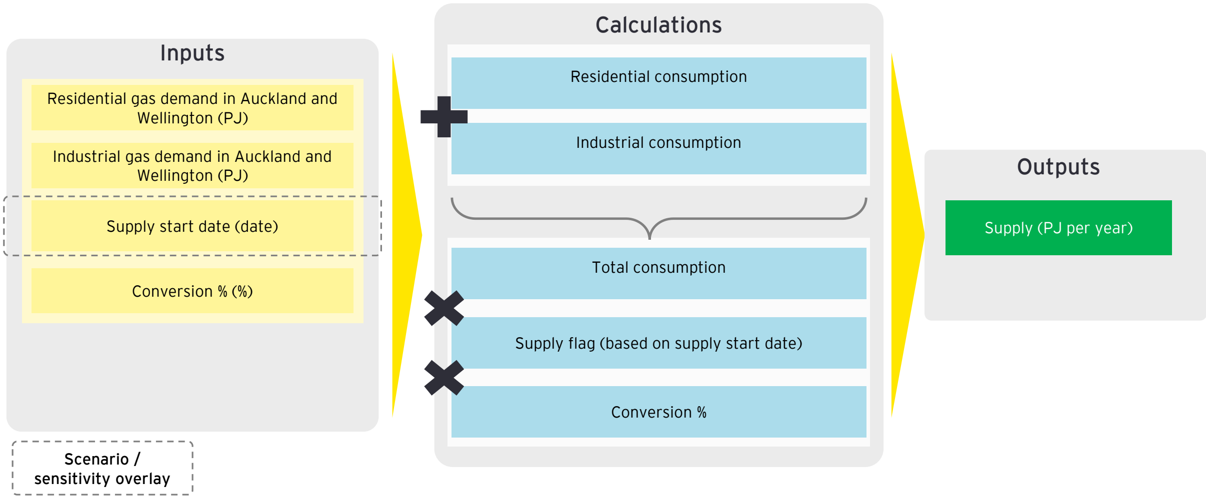


Figure 72: Hydrogen supply forecast methodology

Key inputs in the above methodology include the following:

- Residential consumption of natural gas in Auckland and Wellington which will be blended with hydrogen.
- Commercial/industrial consumption of natural gas blended in Auckland and Wellington which will be blended with hydrogen.
- Supply start date, representing the year in which supply of hydrogen will commence.
- A conversion percentage (%) of 6% on an energy basis, representing a hydrogen to natural gas blend ratio of 20% on a volumetric basis.

Under these assumptions hydrogen would be injected into the distribution network in Auckland and Wellington. This is based on the assumption that distribution network materials and connected equipment would be lower risk in terms of compatibility than those of the transmission network.

The key calculations are summarised in the Table 81 below.

Table 81: Hydrogen production calculations

Component	Calculation approach	Sources for inputs
Total residential/commercial gas demand	= (residential demand) + (commercial/industrial demand)	*Residential/Commercial/Industrial gas demand in Auckland and Wellington:* Estimated based on gas consumption data and proportion of Auckland/Wellington and Residential/Commercial/Industrial demand in 2022.
Supply flag	=IF(year > supply start date, 1 , 0)	*Supply start date:* based on potential timeframe to blend in GTP Castalia report and varied across scenarios
Total supply	= (total consumption) x (supply flag) x (conversion %)	*Total consumption:* discussed above
		Supply flag: discussed above
		Conversion %: 6% on an energy basis, based on a blend ratio of 20% by volume

The following key assumptions and limitations are highlighted with regard to the above methodology:

- The methodology does not allow hydrogen supply to return to zero once supply commences.
- In the years after supply commences, supply is sensitive to the forecast total residential and commercial/industrial consumption of natural gas blended with hydrogen. These forecasts are based on 2022 demand figures in Auckland and Wellington and the proportion of gas used for domestic and commercial/industrial consumption.

B.2.4 Prospective/LNG

The modelling methodology is summarised in the diagram below.

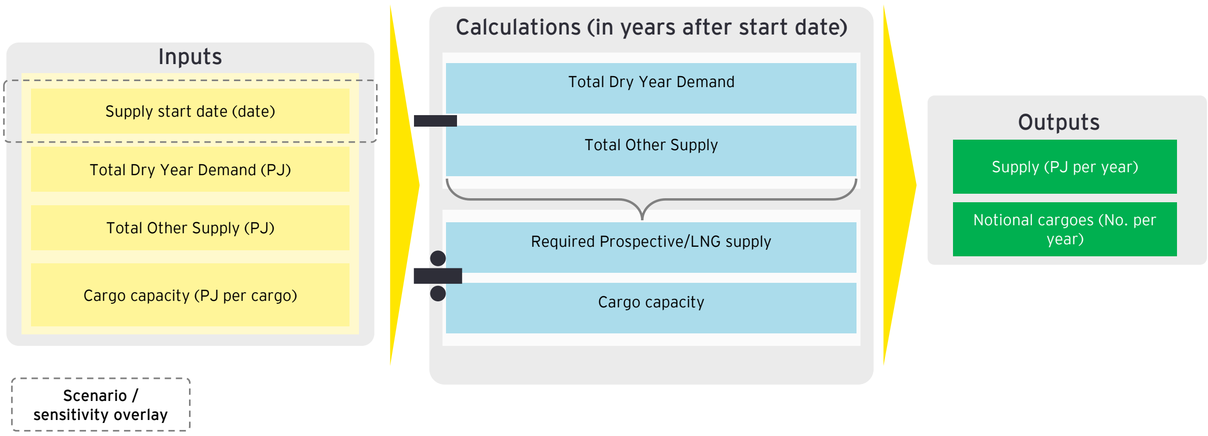


Figure 73: Prospective LNG supply forecast methodology

Key inputs in the above methodology include the following:

- Supply start date, representing the year in which supply of prospective resources/LNG will commence and the lead time to construct the necessary import and storage infrastructure and/or de-risk prospective resources.

- Remaining demand requiring supply after natural gas, biogas and hydrogen supply has been calculated.

- Cargo capacity, the PJ of gas per cargo based on the GTP LNG Report (4 PJ per cargo).

The key calculations are summarised in Table 82 below.

Table 82: LNG production calculations

Component	Calculation approach	Sources for inputs
Supply flag	=IF(year > supply start date, 1 , 0)	*Supply start date:* based on time to start gas import/develop prospective resources and varied across scenarios
Modelled LNG Supply	=((Total Dry Year Demand) – (Modelled Supply from Other Sources)) x (Supply Flag)	*Total Dry Year Demand*: All demand. From demand model.
		Modelled Supply from Other Sources: 2P Production, 2C Production, Biogas Supply, Hydrogen Supply. From other sheets in Supply model.
		Supply flag: discussed above
Notional no. cargoes per year	=(Modelled LNG Supply) / (cargo capacity)	*Modelled LNG Supply:* discussed above
		Cargo capacity: 4 PJ, based on GTP LNG Report

In summary, prospective/LNG supply is equal to the gap between other supply and the dry year gas demand. The number of cargoes per year is the prospective/LNG supply divided by the capacity of each cargo (assumed to be 4 PJ based on the GTP LNG Report).

B.3 Price outcomes model methodology

B.3.1 Gas pricing model

The modelling methodology is summarised in the below diagram.

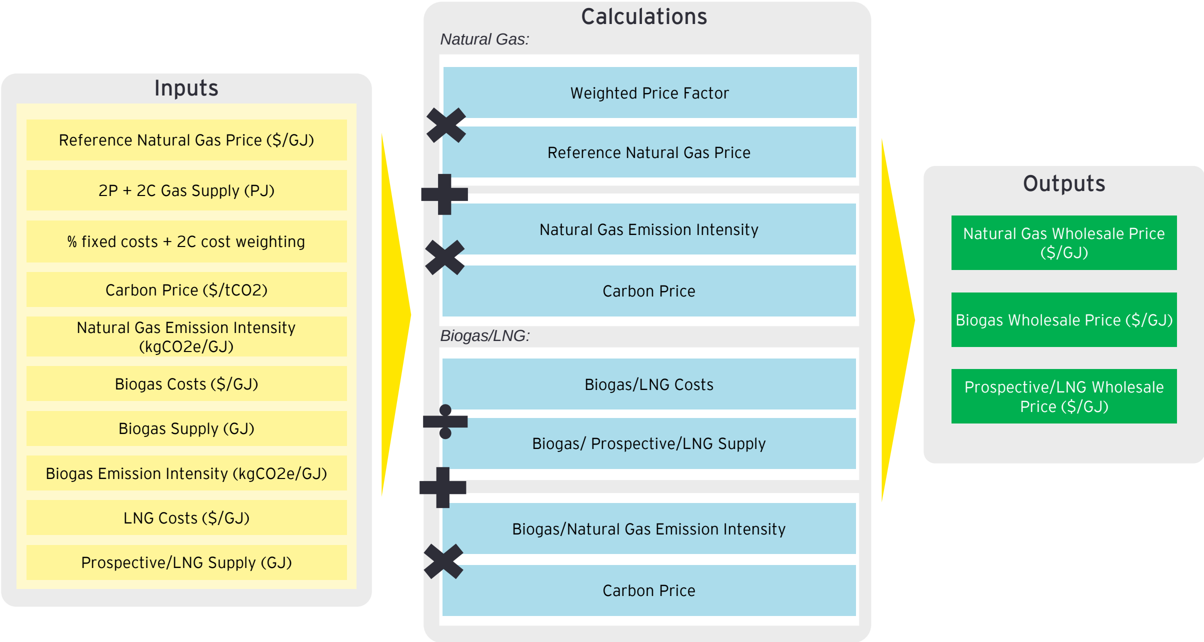


Figure 74: Gas pricing model methodology

Key inputs in the above methodology include the following:

- Reference natural gas price serving as the baseline commodity price of natural gas
- Weighted price factor acting as a multiplier that modifies the reference natural gas price in response to the annual shifts in the balance between fixed and variable cost
- Carbon price representing the price that must be paid per tonne of CO_2 released under the emissions trading scheme
- Natural gas emission intensity is the emissions released per unit of natural gas consumed
- Biogas costs is the cost of biogas supply from different sources of biogas
- Biogas emission intensity is the emissions released per unit of biogas consumed
- Prospective/LNG costs cover the fixed and variable costs associated with LNG import as proxy for higher cost gas from either prospective resources or LNG supply

The key calculations are summarised in Table 83 below.

Table 83: Gas pricing model calculations

Component	Calculation approach	Source for inputs
Natural gas Price ($/GJ)	= (Reference natural gas price) * (Weighted Price Factor)	*Reference natural gas Price*: Assessment of MBIE gas price data
Weighted Price Factor	= % fixed costs * (1 - no. major production facilities operating/total no. current major production facilities) + (2P production + 2C production * 2C cost weighting) * %variable costs / (2P + 2C Production)	*2P + 2C Production*: modelled supply *% Fixed/Variable Costs*: EY Consultation with upstream operators

Component	Calculation approach	Source for inputs
Natural Gas Carbon Impost ($/GJ)	= (Carbon Price) * (Natural gas emission intensity)	*Carbon Price:* CCC Demonstration Path *Natural gas emission intensity*: system average emissions intensity from GIC
Biogas Price ($/GJ)	= sum((Biogas Cost per tranche) * (biogas supply per tranche)) / (Biogas supply)	*Biogas Supply*: Supply Model *Biogas Cost:* GTP Biogas Research Report, page 33
Biogas Carbon Impost ($/GJ)	= (Carbon Price) * sum((Biogas Emission Intensity per source) * (Biogas Supply per source)) / (Biogas supply)	*Biogas Emission Intensity:* GTP Biogas Report Table 5-5
Prospective/LNG Price ($/GJ)	= (LNG Commodity price) + (LNG variable costs) + (LNG fixed costs)) / (Prospective/LNG supply)	*LNG Supply:* Supply Model *LNG Commodity Price:* Enerlytica Report *LNG Variable Cost:* Enerlytica Report *LNG Fixed Costs:* Enerlytica Report
LNG Carbon Impost ($/GJ)	Same as the Natural Gas Carbon Impost above	LNG is identical to natural gas once re-gasified

The following key assumptions and limitations are highlighted with regard to the above methodology:

- The model relies on a single assumption for each fixed and variable cost component of each respective gas type which is reflective of current prices. However, these cost parameters would likely vary in response to changes over the 30-year span of the modelling period.

B.3.2 Residential user cost model

The modelling methodology is summarised in the diagram below.

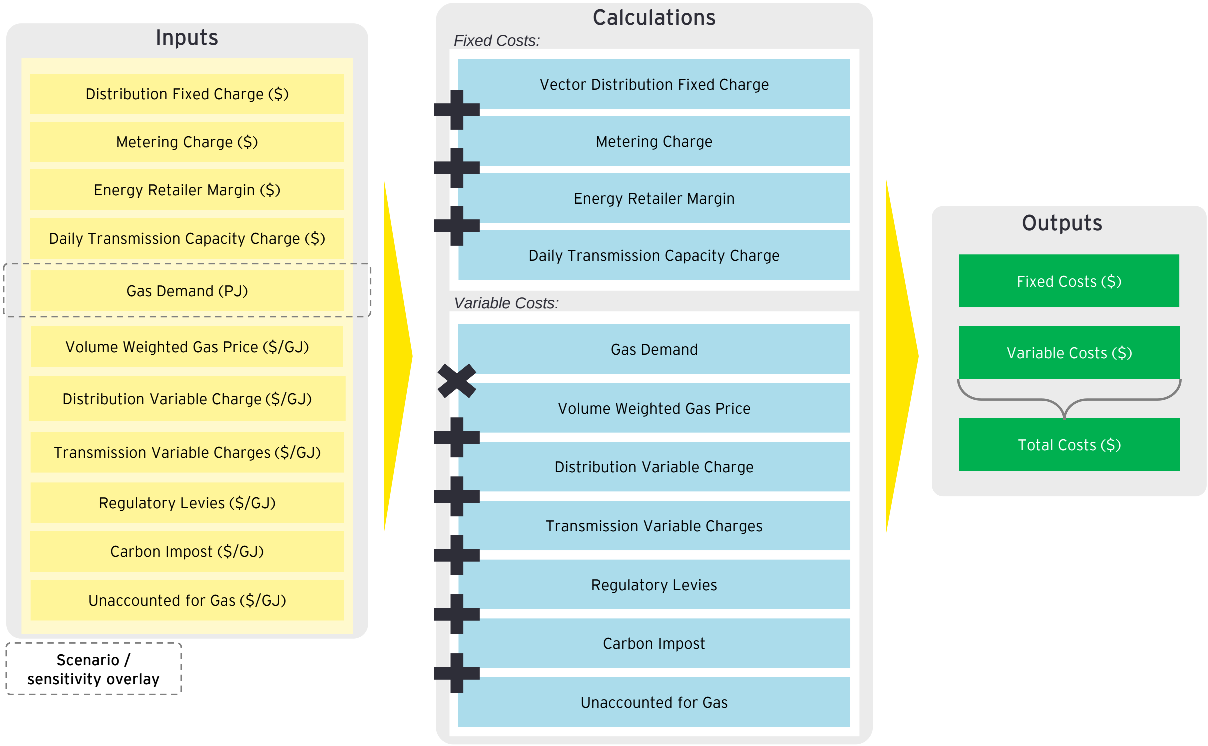


Figure 75: Residential user cost model methodology

Key inputs in the above methodology include the following:

- Distribution fixed charge is the fixed charge portion of the distribution costs for natural gas through the distribution network
- Metering charge is a fixed fee to cover the fixed costs associated with gas supply
- Energy retailer margin is the return to energy retailers
- Daily transmission capacity charge, the fixed charge for reserve capacity on the transmission system
- Volume weighted gas price reflects the average price of the different gases weighted according to their relative quantities within the supply mix
- Distribution variable charge is the variable charge portion of the distribution charges
- Transmission variable charges are the transmission charges per unit of gas transported through the transmission system
- Regulatory levies is a variable charge on gas that funds regulatory oversight
- Carbon impost is an additional variable cost to account for the emissions produced during the combustion of the gas
- Unaccounted for gas is an allowance for the difference between the total gas entering the gas network and the delivered to customers and allocated to users

The key calculations are summarised in Table 84 below.

Table 84: Residential user cost model calculations

Component	Calculation approach	Source for inputs
Total Costs ($)	= (Fixed Costs) + (Variable Costs)	
Fixed Costs ($)	= (Distribution fixed charge) + (Metering Charge) + (Energy Retailer Margin) + (Daily Transmission capacity charge)	*Distribution fixed charge*: Distribution pricing schedule *Metering Charge*: Confidential *Energy Retailer Margin*: Confidential *Daily Transmission capacity charge*: Transmission pricing schedule
Variable Costs ($)	= (User gas demand) * ((Volume weighted gas price) + (Vector distribution variable charge) + (Transmission charges) + (Regulatory levies) + (Carbon Impost) + (Unaccounted for gas))	*User gas demand*: 15 GJ for small residential users and 40 GJ for large residential users based on industry input *Volume weighted price*: Wholesale gas price model *Distribution variable charge*: Distribution pricing schedule *Transmission charges*: Transmission pricing schedule *Regulatory levies*: GIC website *Volume Weighted Carbon Impost*: Wholesale gas pricing model *Unaccounted for gas*: Industry assumption

The following key assumptions and limitations are highlighted with regard to the above methodology:

- The model operates on a singular assumption for all cost components which are reflective of current prices, excluding the gas price and carbon impost which reflect the annual supply conditions of the scenario. However, these cost parameters would likely vary in response to changes over the 30-year span of the modelling period.

B.4 Emissions model methodology

The modelling approach has been to use the three parts of the gas supply system to identify the potential emissions sources. The three components of this model are summarised in the diagram below.

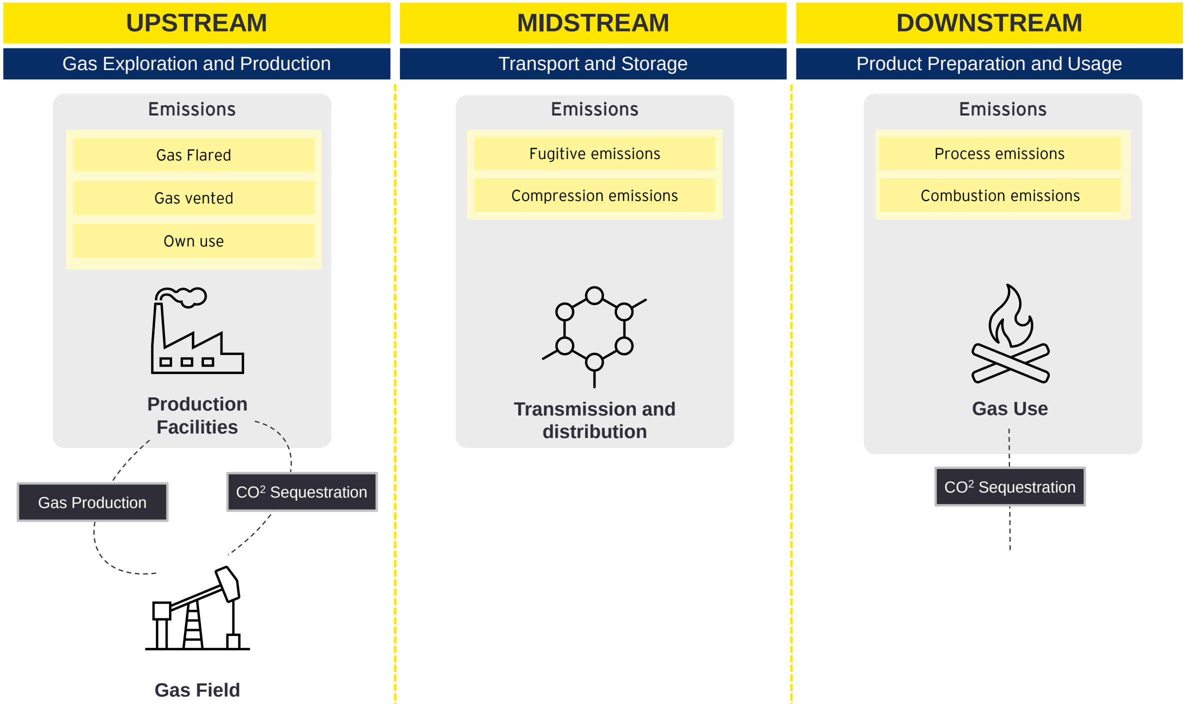


Figure 76: Emissions model components

This model only considers emissions form the use of natural gas. It does not consider the impacts of fuel substitution. For example if a decrease in natural gas use were to increase coal use, then the increase in emission would not be incorporate into this model. Moreover the model does not consider emissions leakage impacts of reduction of emissions in New Zealand that could increase global emissions.

B.4.1 Upstream

The modelling methodology is summarised in the diagram below.

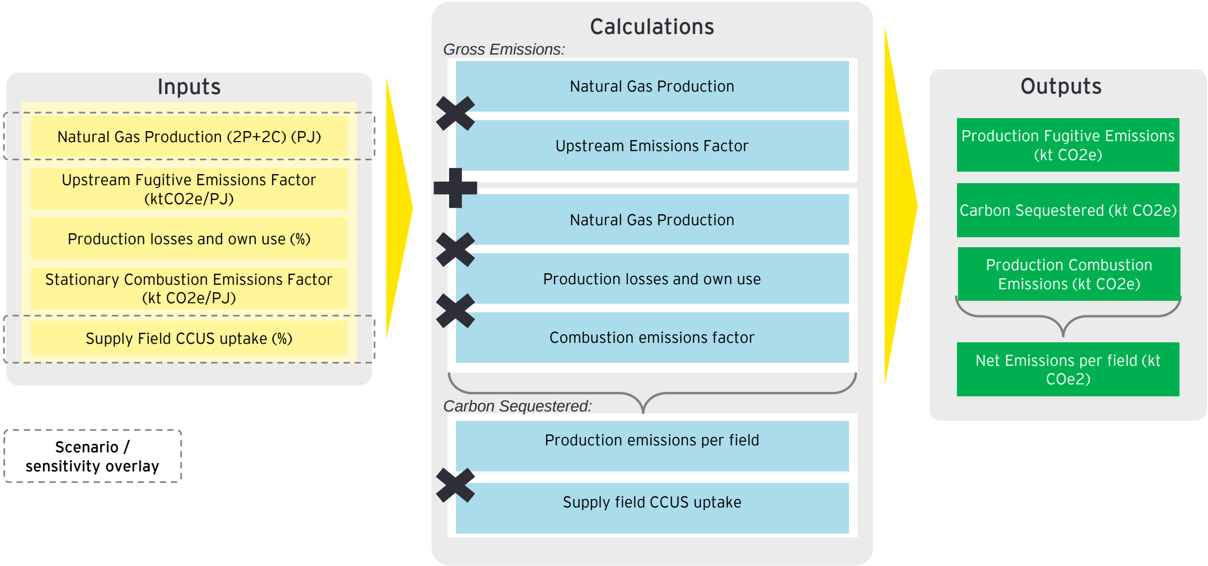


Figure 77: upstream emissions model methodology

Key inputs in the above methodology include the following:

- Upstream emissions factor is the fugitive emissions released per unit of production (includes flaring and venting)
- Supply Field CCUS uptake is the percentage production fugitive emissions sequestered
- Production losses and own use is the percentage of gas consumed for gas processing activities

The key calculations are summarised in Table 85 below.

Table 85: Upstream emission calculations

Component	Calculation approach	Source for inputs
Total Upstream Emissions(kt CO2e)	= (Production combustion emissions) + (Production fugitive emissions) – (CO2 sequestered)	
Upstream fugitive emissions (kt CO2e)	= (Upstream fugitive emissions factor) * (Production)	*Upstream Emissions Factor*: Based on an analysis of MBIE gas and emissions reporting data
CO2 sequestered	= (Production Emissions) * (Supply Field CCUS Uptake)	*Supply Field CCUS Uptake*: Scenario Input
Upstream combustion emissions	= (Upstream losses and own use) * (Production) * (Stationary combustion emissions factor)	*Upstream losses and own use:* Based on an analysis of MBIE gas and emissions reporting data *Station combustion emissions factor:* MFE emission reporting guidance

B.4.2 Midstream

The modelling methodology is summarised in the diagram below.

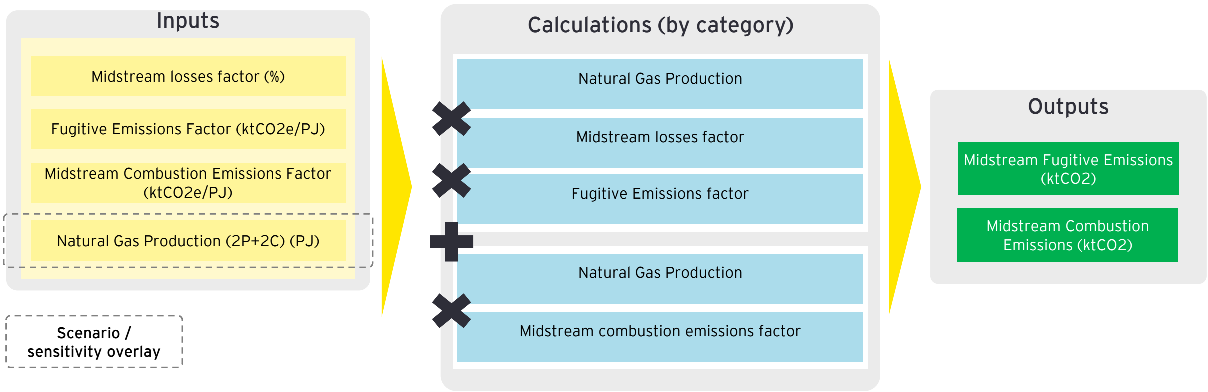


Figure 78: midstream emissions model methodology

Key inputs in the above methodology include the following:

- Midstream fugitive losses factor is the percentage of gas which is lost from the transmission and distribution systems
- Emissions factor is the emissions released per unit of gas lost form the transmission and distribution systems
- Midstream combustion emission factor is the compression station emission per unit of production

The key calculations are summarised in Table 86 below.

Table 86: Midstream emission calculations

Component	Calculation approach	Source for inputs
Midstream Fugitive Emissions (kt CO2e)	= (Midstream losses factor) * (Production) * (Emission Factor)	*Midstream losses factor*: based NZ Greenhouse Gas Inventory reporting and analysis of MBIE emission reporting *Emission Factor*: NZ Greenhouse Gas Inventory
Midstream Combustion Emissions (kt CO2e)	= (Midstream combustion emissions factor) * (Production)	*Midstream combustion emission factor:* based on analysis of MBIE gas and emissions statistics.

B.4.3 Downstream

The modelling methodology is summarised in the diagram below.

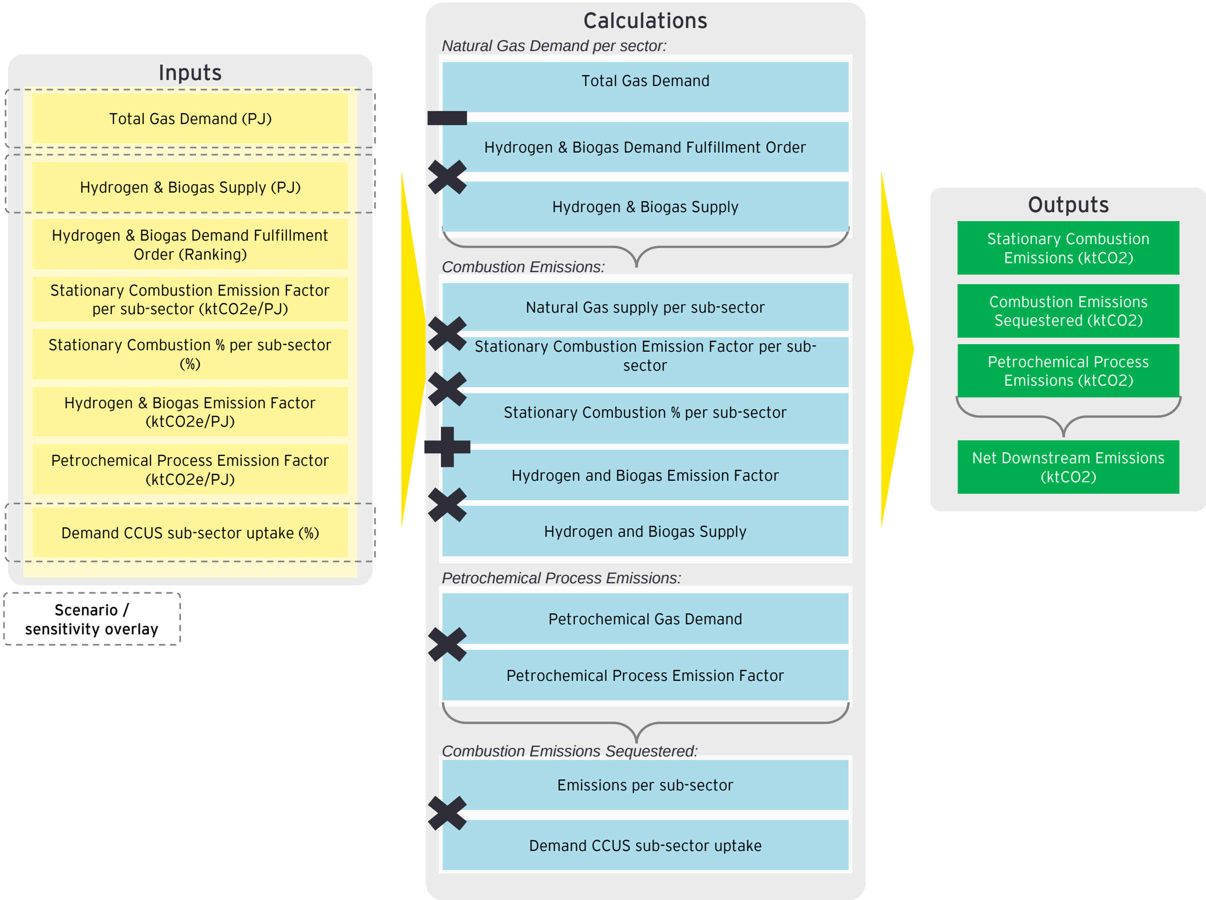


Figure 79: Downstream emission model methodology

Key inputs in the above methodology include the following:

- Hydrogen and biogas demand fulfilment order is the priority of user groups that can most readily transition to using these alternative fuels
- Stationary combustion emission factor is the emissions generated per unit of fuel consumed for each user group
- Stationary combustion percentage is the percentage of each users total gas demand allocated towards stationary combustion
- Hydrogen and biogas emission factor is the emissions generated by use of hydrogen and biogas as fuel
- Petrochemical process emission factor is the emissions generated during the process of transforming natural gas from feedstock into its final product
- Demand CCUS sub-sector uptake is the percentage of emission sequestered each sector

The key calculations are summarised in Table 87 below.

Table 87: Downstream emission calculations

Component	Calculation approach	Source for inputs
Net Downstream Emissions (kt CO2e)	= (Downstream Emissions) – (CO2 sequestered)	
Downstream Emissions (kt CO2e)	= (Combustion Emissions) + (Process Emissions)	
Natural gas supply per sub-sector (PJ)	= (Gas Demand) – (Biogas and hydrogen supply)	
Biogas and Hydrogen Supply per sub-sector (PJ)	= Allocation of biogas and hydrogen supply to sector based on (Priority ranking) until all biogas and hydrogen supply allocated	*Priority ranking:* based on analysis of suitability fir biogas and hydrogen supply
Combustion Emissions (kt CO2e)	= (Stationary combustion gas demand) * (Stationary combustion emission factor) + (biogas and hydrogen gas demand) * (biogas and hydrogen emissions factors)	*Stationary combustion emission factors*: As per the Ministry for the Environment's guidance on combustion emission factors *Biogas and hydrogen emissions factors:* biogas factors based on the Biogas GT report and hydrogen emissions assumed to be zero
Process Emissions (kt CO2e)	= (Process gas demand) * (Petrochemical Process Emission Factors) for the Petrochemical sub-sectors	*Petrochemical Process Emission Factors*: Based on an analysis of MBEI gas and emissions reporting data
CO2 sequestered (kt CO2e)	= (Downstream emissions) * (Demand CCUS sub-sector uptake)	*Demand CCUS sub-sector uptake*: Scenario Input

Appendix C Petroleum reserves and resources definitions

The Society of Petroleum Engineers (SPE) maintains the Petroleum Resources Management System (PRMS) to provide standards for reporting on oil and gas accumulations – defined as petroleum resources. Petroleum resources are naturally occurring gas and liquid hydrocarbons.

This reporting framework helps oil and gas practitioners navigate the technical and commercial uncertainties that underpin assessment of how much oil and gas could be produced. Information on the framework from version 1.03 of the guidance is summarised in this section[141]. Any quoted material in this Appendix can be found in Section 1.1 of that document.

Figure 80 shows the PRMS petroleum resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Resources.

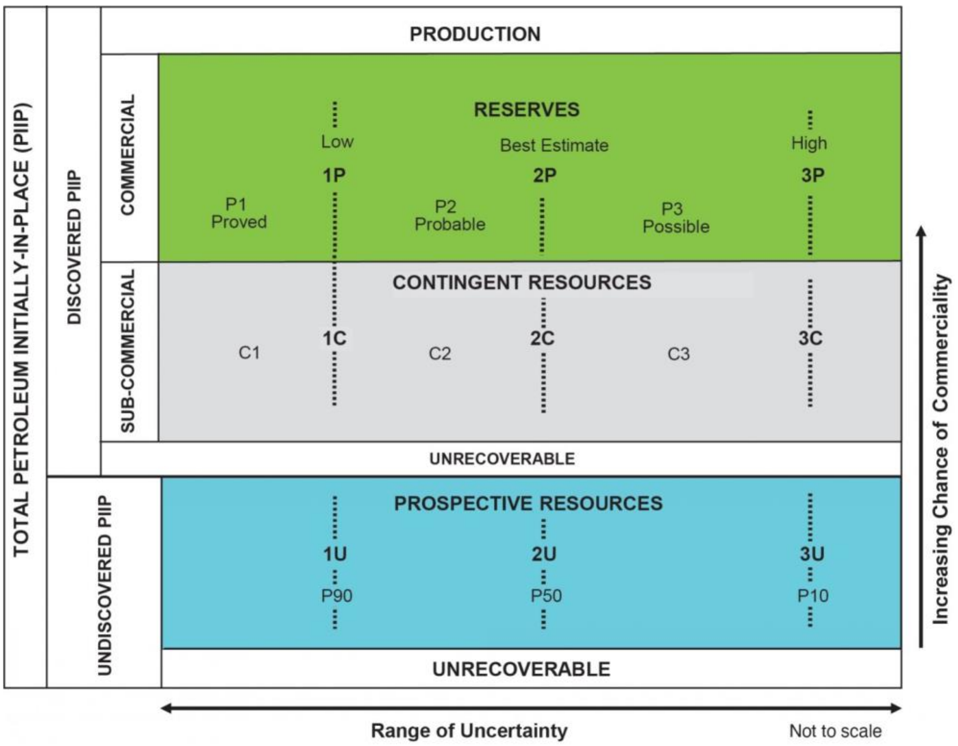


Figure 80: Resources classification framework

There are two important concepts that underlie the framework:

Uncertainty

As petroleum is naturally occurring and underground, any estimate of the size of the accumulation, its composition and behaviour is inferred using observations and data. Hence the range of uncertainty around these estimates is expressed along a range of uncertainty with 1, 2, and 3 representing the P90, P50 and P10 probabilities respectively. A P10 represents a 10% probability that the given volume will reach or exceed this figure – there is a 90% probability that production or resources will be lower. This is represented by the horizontal access of the diagram.

141 https://www.spe.org/en/industry/reserves/

Chance of commerciality

As more data is collected on an accumulation of petroleum and more work is done to de-risk production, the chance of the production becoming commercial is increased. Once an accumulation is deemed to be commercial, it can be classified as reserves (with an associated probability of being produced). Not all resources will become reserves as the cost to produce them or other barrier may be too high.

The major subdivisions within the resources classification are as follows:

A. *"Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.*

B. *Discovered PIIP is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.*

C. *Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage."*

As petroleum resources are assessed for production, development projects are formulated to understand how the resource will be produced and monetised. In the process of maturing the development plan, resources move from undiscovered, discovered and sub-commercial resources and then to reserves (if economic).

Key definitions in this process are as follows:

A. *"1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.*

   2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) …, as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

   3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. ***Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub- classified based on project maturity and/or economic status.*

C. ***Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.*

D. ***Prospective Resources*** *are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.*

E. ***Unrecoverable Resources*** *are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks. "*

The guidance goes on to detail how these categories can be combined. Key is the following consideration:

"The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided."

Fundamentally it should be remembered that all quantities in this system are probabilistic estimates, so summation of quantities needs to be undertaken with caution.

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