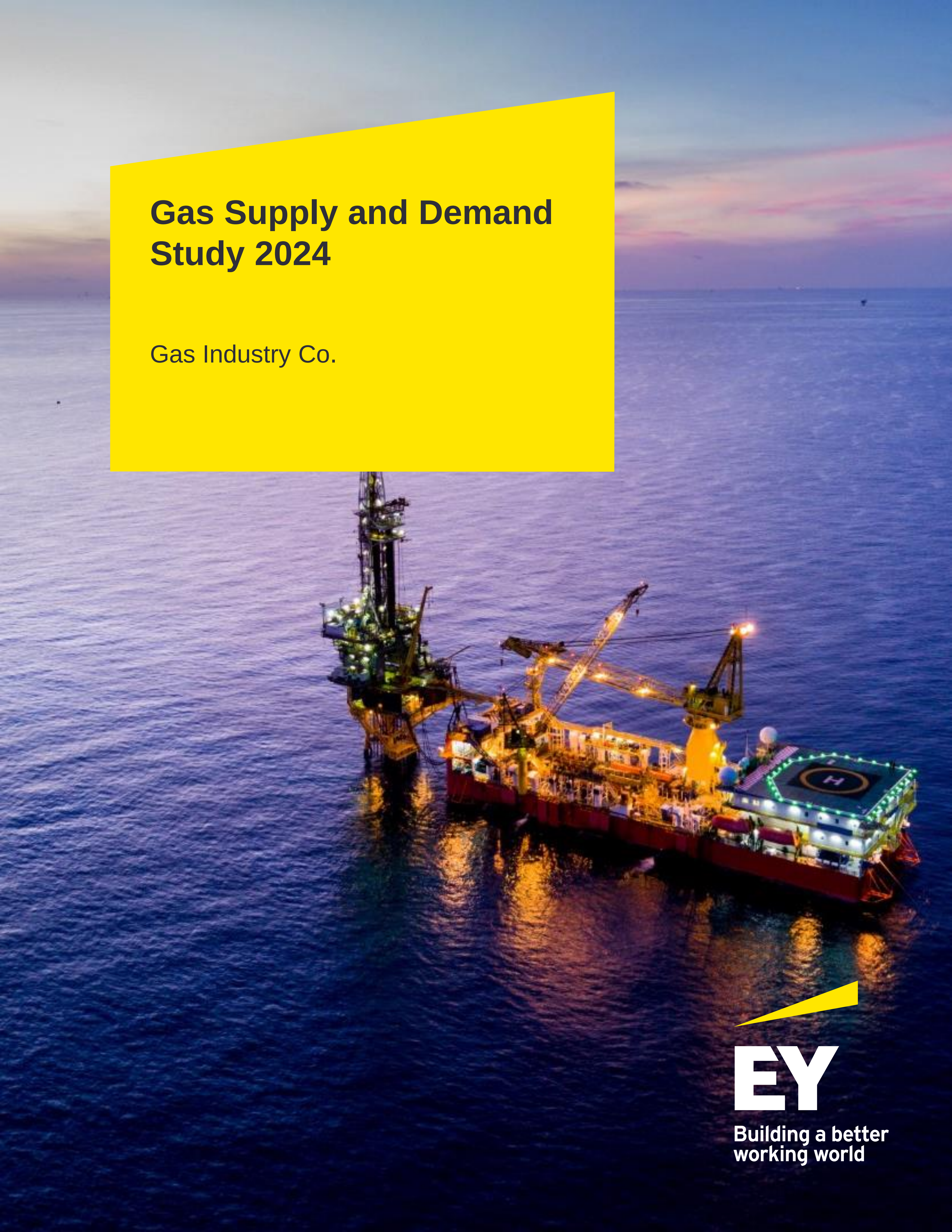
Gas Supply and Demand Study 2024

Gas Industry Co.



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The modelling methodology used in this Report and its limitations are outlined in the Appendix. Modelling work performed as part of our scope inherently requires assumptions about future behaviours and decisions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. EY takes no responsibility that the projected outcomes will occur. EY highlights that the analysis included in this Report does not constitute investment advice or a recommendation to you on a future course of action. EY provides no assurance that the scenarios that have been modelled will be accepted by any relevant authority or third party.

Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios analysed in this Report, and the scenarios and the key assumptions underpinning these scenarios are described in the Report. These scenarios were developed through series of workshops with the Client and the assumptions underpinning the scenarios were selected by the Client. The modelled scenarios represent four probable future options, and it must be acknowledged that many alternative future scenarios exist. Alternative future scenarios beyond those presented have not been evaluated as part of this Report.

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Section 1

Executive Summary

Context and key findings

Study context:

The Gas Industry Company Limited (Gas Industry Co.) commissioned EY to perform the Gas Supply and Demand Study for 2024. The purpose of this study is to better understand the future of gas supply and demand and to provide stakeholders with useful information to make informed decisions.

The modelling considered four scenarios to test a range of outcomes for supply and demand in the gas sector. Several workshops were held with Gas Industry Co. to develop these scenarios to identify the relevant variables and outcomes to be considered. The scenarios explore the potential impacts of different drivers and are not intended to predict the future. There are a range of other possible scenarios and sensitivities that could eventuate that have not been considered in this study.

Demand side drivers across different types of consumers were considered. These included industrial, commercial, residential, petrochemical, and gas-fired electricity generators. On the supply-side, different drivers across possible fuel sources were considered. These included domestic natural gas, biogas, hydrogen, and liquefied natural gas (LNG). The study only considered gas that gets delivered through the transmission and distribution network; additional gas supply and demand may occur outside this network but is not considered here.

Three different outcomes from the modelling were considered: energy security, emissions (where scenarios are compared to the Climate Change Commission's (CCC) demonstration path),[1] and prices.

Energy security outcomes were considered through the lens of demand reduction from commercial and industrial consumers. This study distinguishes reduction in commercial and industrial demand as being due to either closure (where operations are reduced or shut down) or fuel-switching (where the operation continues, using an alternative fuel). These are outputs of the modelling and are a function of input assumptions around the economics of fuel switching for different uses. The purpose of this modelling methodology is to provide insights and enable richer discussion around the evolution of industrial and commercial activity in New Zealand while achieving climate objectives.

As part of last year's study undertaken by EY for Gas Industry Co. (Gas Supply and Demand Study 2023),[2] confidential interviews with key gas suppliers and major consumers were held to align the study with industry viewpoints concerning the availability and commercialisation of natural gas supply in the future. This information has been carried over as an input to this year's analysis. This report does not make any representations for any of the gas industry stakeholders.

The methodology, assumptions, and limitations of the study are discussed in the Appendices, which should be understood when considering the report's findings and outcomes. The study does not consider changes in the midstream gas sector, nor is it an assessment of policy or regulatory changes, economic impacts, or wider environmental impacts. This report does not make any recommendations on a course of action.

Context and key findings

Market context:

New Zealand's upstream gas sector has experienced supply headwinds over the last year. The sector continues to be challenged on three main fronts, lower than expected new supply outcomes from drilling campaigns,[3] regulatory and policy decisions around exploration and decommissioning securities,[4] and the ability to raise capital for fossil fuel extraction.[5] On the downstream side, large consumers have a medium-term focus on reducing or eliminating their use of fossil fuels and electrifying their transportation and low-temperature heat applications.[6] Although a reduction in natural gas demand is expected in the mid- to long-term,[6] there has not been a material reduction in total demand in the recent past (excluding industrial exits and closures).[6]

The combination of a declining supply-side and a steady demand-side has created a material supply deficit. This deficit has been made more apparent by the very low hydro lake levels during July and August of this year,[7] and lower-than-expected output from wind farms, which increased demand for gas-fired electricity generation. The increased demand for gas combined with the gas supply shortage contributed to increased security of supply risk and high electricity prices.[8] The shortage has been managed through two main levers: Methanex (New Zealand's largest gas consumer) has idled its operations and sold its gas to electricity generators,[9] and a decision by Transpower (the system operator), in collaboration with the Electricity Authority Te Mana Hiko, to raise the Contingent Storage Release Boundary thereby increasing access to hydro storage.[10] The unavailability of gas and high energy price poses a risk to the economy, with several major industrial players announcing their intentions to close.[11]

While these supply headwinds are likely to set the scene in the short- to mid-term, the long-term driver for change comes from the need to reduce emissions to meet climate commitments. Over the longer term, a broader range of uncertainties and opportunities may be considered. These might include technological advancement, regulatory changes, consumer preferences, and potential geopolitical shifts. It is important that decisions taken in the short-term do not compromise the ability to succeed on long-term objectives.

Context and key findings

Study findings:

In all scenarios, the study sees total demand for natural gas declining over the horizon to 2050 due to increasing pressure to reduce emissions. This results in a combination of fuel-switching and industrial closures. In all scenarios, cumulative emissions out to 2035 from gas are approximately equal to or lower than the demonstration path scenario from the CCC. The findings from this study can be grouped into four key themes, related to the four scenarios:

1. **The current trajectory of the gas sector indicates a supply shortfall in the short-term.** While the impact of the shortfall this year has been mitigated by Methanex reducing demand, there is still potential for further industrial closures, and reduced security of supply within the electricity sector. How the sector will respond to this shortfall primarily defines the short-term challenge. However, the solution may potentially have long-term consequences.
2. **Importing LNG has the potential to support security of supply within the electricity sector and general availability of gas, but it will come with higher emissions and higher energy costs than domestically produced gas.** Depending on the market settings, the high gas prices could stimulate higher domestic gas production and bring resources that are currently uneconomic into the market, and potentially also encourage activity in exploration. However, the high prices may also create a risk of closure to industrial players, particularly those who are unable to pass the higher costs through to their consumers, for example those competing in international markets where competitors can access cheaper gas. Only downstream emissions from LNG would be counted under the NZ ETS, but upstream emissions associated with producing LNG would still contribute to global emissions.
3. **If Methanex were to exit immediately, demand would reduce materially. However, it may also result in considerable reduction in supply side investment.** This is because Methanex is currently the only "*firm and term*" consumer (meaning they require a long-term contract for a constant supply of gas) in the market. Such "*firm and term*" contracts are necessary to de-risk supply-side development. Furthermore, because Methanex has historically been prepared to flex its demand, the absence of Methanex may limit the gas sector's ability to support electricity generation, particularly for peaking and dry year demand. Without Methanex, the country may still require imported LNG to support demand in the medium to long term.
4. **It is generally accepted by the energy industry that a highly renewable energy sector is the goal in the mid- to long-term, but finding an optimal transition to reach that goal is a complex task.** This will require detailed consideration of, and coordination across, a range of fuels, technologies, end-uses, and their respective physics. A detailed assessment of how this transition should take place, and an action plan to enable it, is out of the scope of this report. From a gas sector perspective, imposing regulations and restrictions on the upstream gas sector can only be effective if natural gas consumers have a technically and commercially viable renewable alternative. This switching must also be coordinated with supply of these alternative energy sources and reductions in upstream gas supply. This level of coordination goes beyond the purview of the gas sector alone.

Scenarios

Four scenarios have been analysed as part of the scope of this work. These scenarios were developed during several workshops with Gas Industry Co., and represent a few of the many possible scenarios. The first three scenarios primarily consider actions and uncertainties from within the gas sector, and they are analysed within a quantitative framework. The fourth scenario is different in that it hinges on actions and uncertainties from outside the gas sector, for example the cost, timing, and incentivisation of renewable alternatives. For this reason, the scenario is not analysed quantitatively, but rather it is discussed qualitatively and outlines the key uncertainties that require further analysis. The four scenarios considered in this report are:

Low intervention

Purpose: To test a future where supply continues to be challenged and there is little intervention to develop further supply or actively address demand.

Overview: The market continues to experience a supply shortfall. No additional supply resources are discovered or imported.

Due to scarcity, natural gas and energy prices remain high. For many industrial and some commercial users (including Methanex) it is no longer financially viable to use gas. Methanex chooses not to renew its contract when it expires in 2028 and exits New Zealand, which impacts the ability to underwrite new gas supply.

LNG import

Purpose: To test a future where LNG is imported to resolve the supply shortfall. This opens the door to higher demand within the electricity and petrochemical sectors.

Overview: LNG imports start from 2026 onwards. LNG supports the electricity sector through providing dry year reserve in the short term and peaking as domestic supply winds down. The industrial and petrochemical sectors rely on domestic supply.

Two possible alternative supply-side arrangements are considered within this scenario.

1. A **split market**, where LNG provides flexibility to gas-fired electricity generation. This arrangement tests the impact of limiting industrial consumers' exposure to LNG prices.
2. A **single price** is set by the marginal supplier, meaning all market participants are exposed to LNG prices in some periods.

Scenarios

Methanex exits immediately

Purpose: To test a future where it is assumed that the largest consumer exits abruptly, to understand the impact of disrupting the supply-demand balance significantly, and the impact on future energy security.

Overview: Forecasted ongoing supply issues lead to the abrupt closure (assumed) of Methanex, with all operation ceased by the end of 2025.

Whilst Methanex leaving releases supply, this could also cause investment in domestic gas to decline. By freeing up a chunk of demand, other users are able to access gas that would otherwise be used by Methanex. However, the exit of Methanex also impacts the supply-side, as it is no longer available to provide firm-and-term contracts to underwrite new supply.

High renewables

Purpose: To test a future where an orderly transition shifts New Zealand towards renewable alternatives. The scenario is not analysed within a quantitative framework because it is heavily dependent on events outside the gas sector. Rather, here we establish a high-level outline of the potential scope for the required analysis to support this transition.

Overview: The scenario sees demand for natural gas reducing as renewable alternatives become economic or are incentivised along with a high level of coordination with the upstream sector which means that supply is still available to those who require it.

The scenario is dominated by fuel switching through capital expenditure on electric heat pumps, electrode boilers, electric arc furnaces, ground-source heat pumps, and geothermal high temperature heat. These new technologies run on fuel sources such as wind, solar, geothermal, batteries, biomass, wood pellets, and biogas.

Modelled outcomes - Energy security

Across the four scenarios, energy security is analysed by examining the reduction in demand from commercial and industrial sectors, with higher unmet demand indicating lower energy security. Dry year energy security in particular is discussed in greater detail on page 45. Figure 1 shows the estimated cumulative amount (over time) of curtailed or unmet demand from now until 2025, 2030, and 2035 in each of the three quantitative scenarios. This is split into 3 categories:

- Supply shortfall (DR available) – where there is insufficient supply to meet demand, but industry (particularly Methanex) is assumed to be able to provide demand response (DR) to cover the difference by reducing output.
- Supply shortfall – where there is insufficient supply to meet demand, and industry is unable to provide DR to cover the difference. Consumers are unable to accommodate the shortfall and therefore some customers would not be supplied.
- Closures – where either the energy price, or the ongoing unavailability of gas, may likely lead to industrial and/or commercial gas consumers reducing or shutting down their operations. This contrasts with fuel-switching, where the consumers maintain their operations but use an alternative fuel. Fuel-switching is treated as reduced demand, as opposed to unmet demand, and is shown in the demand forecast for each scenario.

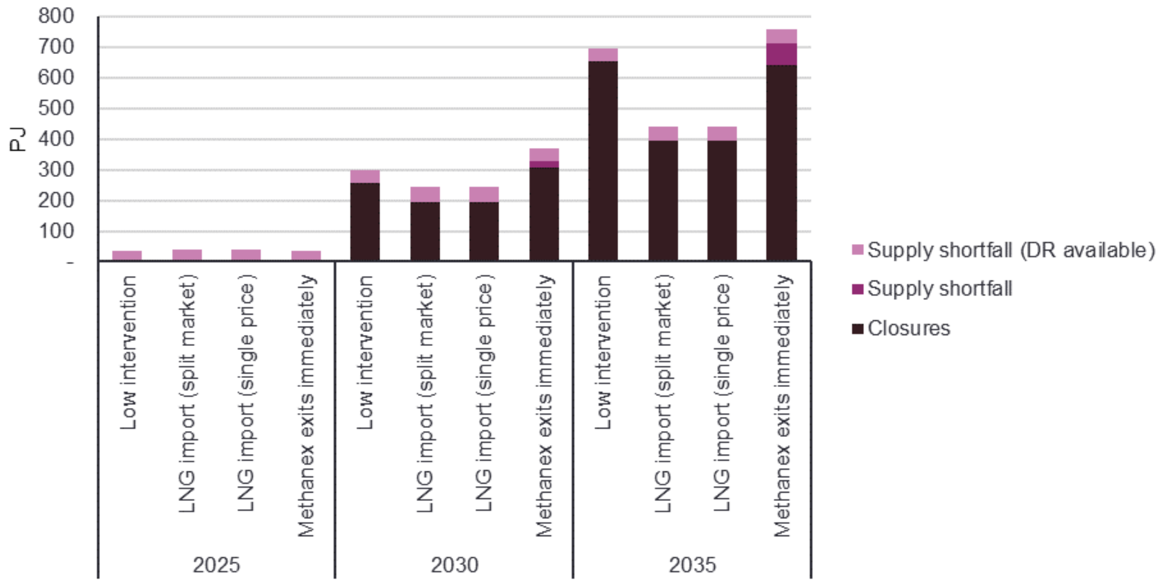


Figure 1: The cumulative amount of unsupplied natural gas demand from now until 2025, 2030, and 2035.

Modelled outcomes - Energy security

In the ***Low intervention*** scenario, the lack of energy security manifests as industrial closure and some supply shortfall. DR is available for much of the supply shortfall as Methanex stays in the market until 2028.

In the ***LNG import*** scenario, LNG bolsters security within the electricity sector. Some shortfall and closures still occur, however, energy security is improved relative to the Low intervention and Methanex exits immediately scenarios.

In the ***Methanex exits immediately*** scenario, the lack of energy security leads to the closure, or mothballing, of all three methanol trains. Methanex's closure frees up supply for other consumers. Without Methanex, the availability of DR is substantially reduced, resulting in increased challenges to security of supply in the electricity sector, particularly in a dry year.

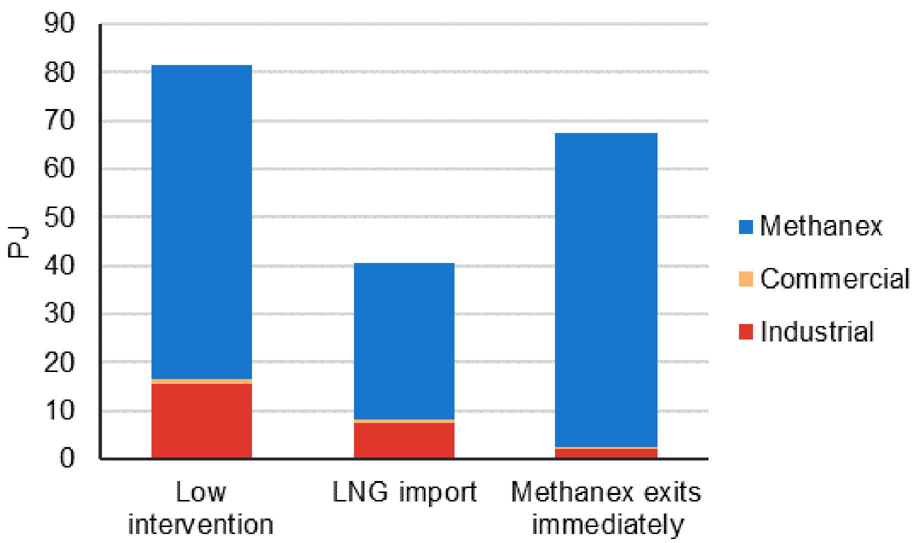


Figure 2: The unsupplied natural gas demand in 2035 due to closures (on an annual, rather than cumulative, basis).

Figure 2 shows the estimated amount of unsupplied gas in 2035 (not cumulative) due to industrial closures. The figure includes how closures are split between industrial consumers, commercial consumers and Methanex.

In the ***High renewables*** scenario, it is expected that additional renewable energy sources would be phased in over time to reduce demand for gas, while ensuring adequate confidence in the market for the short- and medium-term to maintain security of supply. Energy security within the ***High renewables*** scenarios needs to consider how to firm intermittent sources of electricity generation (such as wind and solar), balance the seasonal differences in demand, and provide a dry-year reserve. This security ideally comes at a price that enables domestic industry to remain competitive in the global market.

Modelled outcomes - Emissions

Figure 3 shows the estimated cumulative emissions by 2035 in each of the three quantitative scenarios. We compare these scenarios to the demonstration path published by the CCC.[1] Emissions are categorised according to where within the industry they occur - LNG import emissions, upstream, midstream, and downstream (which is further split according to demand components). LNG import emissions include all upstream, import, and regassification emissions (around 30% of these would be counted in the NZ ETS). No Carbon Capture, Utilisation and Storage (CCUS) has been assumed in any scenario.

In the ***Low intervention*** scenario, the strong headwinds that impact the supply sector result in materially lower emissions the CCC estimates because of the closure of emissions intensive industries. Cumulative emissions in this scenario reach around 50 $MtCO_2e$ compared to 72 $MtCO_2e$ in the CCC demonstration path.

In the ***LNG import*** scenario, the higher gas usage and the LNG shipping and regassification process mean higher emissions than the other scenarios.

Cumulative emissions in this scenario reach around 70 $MtCO_2e$. LNG import emissions include all associated emissions, including upstream and shipping, some of which lie outside the NZ ETS. Note that the intensity of emissions related to LNG imports is much higher than those related to domestically producing natural gas; LNG import emissions are around 3 times higher per PJ of gas than the upstream emissions for domestic gas.[37,39,40,41] This is due to the emissions intensity of the liquefaction and transport of LNG.

In the ***Methanex exits immediately*** scenario, emissions are reduced primarily due to Methanex's closure. Cumulative emissions in this scenario reach around 60 $MtCO_2e$.

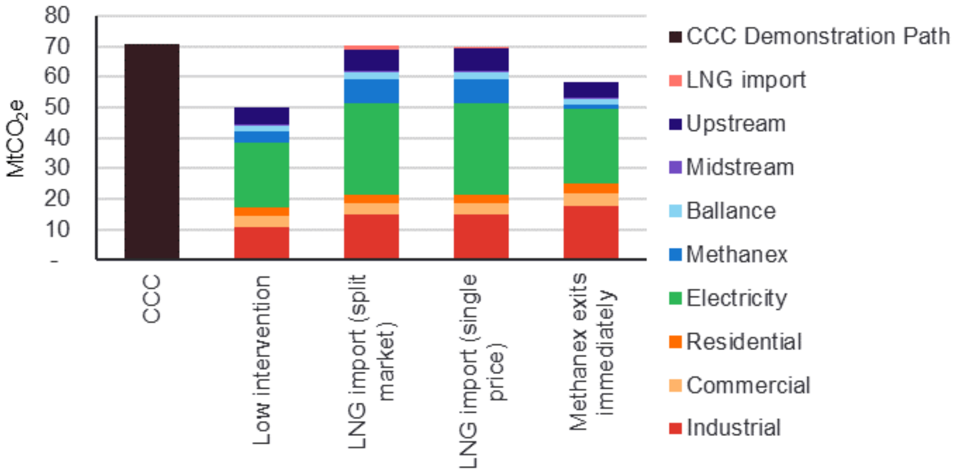


Figure 3: The cumulative emissions by 2035 in each scenario.

Modelled outcomes - Prices

Figure 4 shows the average annual natural gas price in 2026 and 2035 in each of the three quantitative scenarios. Where LNG is imported, we show the price of both domestic natural gas and imported LNG.

In the ***Low intervention*** scenario, wholesale prices are estimated to be around $16/GJ in 2026 and rise to around $28/GJ by 2035 due to declining volumes and proportionally higher fixed costs.

In the ***LNG import (split market)*** scenario, prices are around $100/GJ for LNG and $16/GJ for domestic gas in 2026.[33,36] By 2035, LNG prices are around $38/GJ, while domestic gas prices are around $23/GJ. The high price for LNG is due to a large fixed operational expenditure, and low import volumes. It is assumed that electricity generators will be able to pass the increased price on to customers. On the other hand, industrial and commercial consumers are assumed to be more price sensitive, particularly if they cannot pass the costs onto their customers. For this reason, they only access gas from the domestic market and are therefore shielded from the LNG price.

In the ***LNG import (single price)*** scenario, prices are estimated to be around $100/GJ for all consumers in 2026, and $38/GJ in 2035. This is set by the marginal supplier, which is LNG when it is being supplied. The high prices trigger higher domestic natural gas production.

In the ***Methanex exits immediately*** scenario, prices are estimated to be around $17/GJ in 2026 and rise to around $31/GJ by 2035 due to declining volumes and proportionally higher fixed costs.

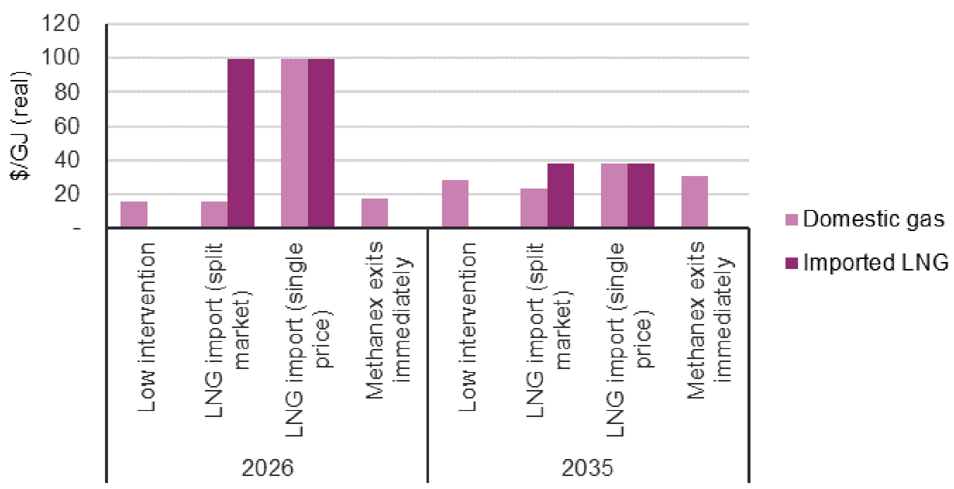


Figure 4: The price of gas ($/GJ) across all quantitative scenarios in 2026 and 2035. 2026 is the first year of LNG imports.

Section 2

Introduction

Background

The Gas Industry Company (Gas Industry Co.) regularly commissions supply and demand studies, which detail 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.

Alongside the Ministry of Business, Innovation & Employment (MBIE) Gas Industry Co. is also involved in the development of the Gas Transition Plan. The Plan's purpose is to understand how the gas industry will transition to a low carbon future and meet the obligations under New Zealand's Emissions Budget. Figure 6 (page 18) provides a high-level overview of the Gas Transition Plan.

EY was commissioned to perform last year's 2023 Gas Supply and Demand Study. Within that report, it was estimated that 2P reserves (the best estimate of commercially viable future natural gas production) would be insufficient to meet demand at some stage between 2025 and 2027. Due to lower-than-expected outcomes from recent drilling campaigns, and subsequent write-downs of estimated 2P reserves, the timing of this shortfall has come forward and the sector is currently experiencing a substantial supply shortfall.[3] The expected supply in the 2023 study suggested approximately 155 PJ of production in 2025. This year, including the write-down on the Kupe field, the data suggests approximately 116 PJ.[12,13] This is a drop of approximately 25% in the amount of expected supply. On the other hand, demand for natural gas has not changed materially, meaning supply may be unable to meet demand over this period.

The supply shortfall has been a contributing factor in several decisions from within industry to close or express concerns around the future.[9,11,14,15,16,17,18,19] Several players have been directly impacted by gas shortages:

- Methanex, which was already operating at significantly reduced capacity, has idled its operations until the end of October 2024.[14] It has publicly announced that it is considering permanent downsizing.[11]
- Ballance, which was relatively sheltered from the current crisis through a supply contract, has expressed concern about its long-term outlook.[15]
- Contact Energy purchased gas from Methanex to run its gas-fired power generation for the remainder of this year.[9]
- Beach Energy has hinted at a possible divestment of its stake in Kupe.[16]

Other players have been impacted indirectly, by high electricity prices driven in part by gas shortages:

- Winstone Pulp has announced it is closing its central North Island mills, with around 230 jobs to be directly lost.[17]
- NZ Steel has expressed concern about its ability to remain internationally competitive with the current energy supply.[18]

Background

- Oji Fibre has announced the closure of its Penrose paper recycling plant which employs 75 people.[19]

The supply shortfall has been made more apparent by historically low levels in the major hydro-electricity dams. In early August, hydro lakes were around 55% of the average for that time of year, which is around a 1-in-20 year low according to historical records. For this reason, gas has been crucial in preventing supply blackouts in the electricity market. The higher demand for gas due to the dry year, as well as lower available gas supply, has also contributed to higher use of coal-fired electricity generation and record high electricity prices on the spot market.[8]

In the wake of the supply shortfalls, the Government has announced a series of reforms to improve energy security, which included reversing the oil and gas exploration ban, and exploring options for expediting LNG imports.[20] In addition, the Gas Security Response Group was created earlier this year.[21]

The gas sector has historically gone through multiple periods of contraction and expansion which have typically been dictated by the availability of supply. From 2001 to 2003, gross production dropped from 264 PJ to 188 PJ due primarily to declining supply from Maui. This was followed by the development of Kupe, Pohokura, and Mangahewa which arrested the decline and stabilised production. Whether a similar development occurs to arrest or reverse the current decline is highly speculative. Methanex has traditionally adjusted its operations to reflect the availability of supply.

The radar chart in Figure 5 (page 18) illustrates the decline in gas consumption over the last 5 years. The solid black line in the chart shows the present-day consumption, split among the nine components of demand. Each component is normalised to its own level of present-day demand. The chart illustrates that industrial consumption (excluding petrochemical) has reduced by approximately 33%, and Methanex, baseload, and cogeneration (types of electricity generation) have all reduced by around 20%. Residential and peaking (a type of electricity generation used to provide for peak-demand and firm intermittent generation) have increased by around 5%.

We discuss consumption when referring to historical data, rather than demand. We do this to distinguish where consumption may be constrained by supply rather than reflecting lower demand.

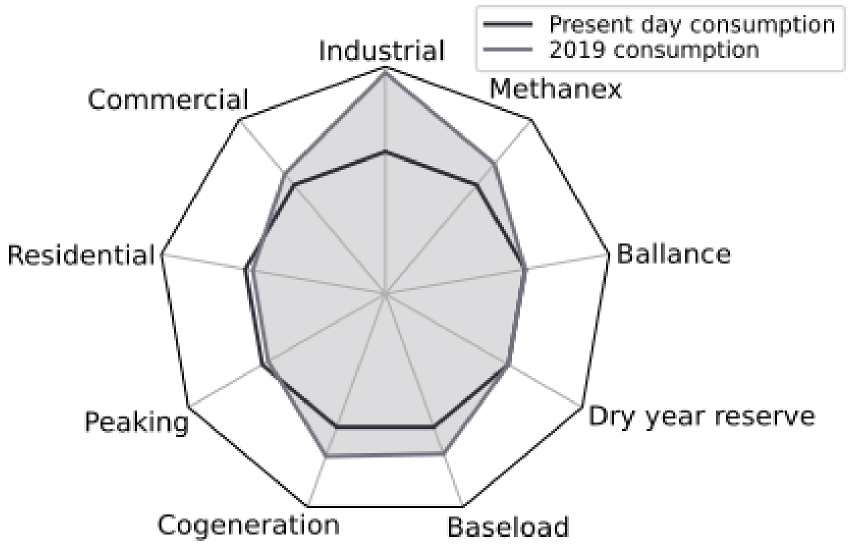


Figure 5: Radar chart depicting the historical changes in gas consumption.

Figure 6: The draft Gas Transition Plan created by Gas Industry Co. [22]

Purpose

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 transition away from natural gas. However, the transition needs to balance reliability and affordability with sustainability. To comprehend these uncertainties, Gas Industry Co. commissioned EY to perform the Gas Supply and Demand Study for 2024. This report presents the findings of this work. Through the analysis, the aim is to provide clarity on some of the possible futures of the gas industry in New Zealand and the potential associated supply and demand forecasts.

The Gas Supply and Demand Study involved developing and modelling a set of scenarios that are representative of a range of possible futures for the industry, with the outcomes presented in this report. The scenarios analysed explore the potential impacts of key drivers and are not designed to predict the future. There are a range of other possible scenarios and sensitivities that could eventuate that have not been considered in this study.

This year's report builds on the Gas Supply & Demand Study 2023 that EY authored. As such, much of the methodology and historical data underpinning the scenarios and analysis remains consistent with last year.

In undertaking this work, various aspects of the supply and demand uncertainties have been examined, including production volumes and demand across different users. 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 Gas Industry Co. were held to better understand how these uncertainties could impact the future investment outlook of the gas industry. As part of the previous year's study (Gas Supply & Demand Study 2023), a number of confidential interviews with key gas suppliers were held to align the modelling methodology with industry viewpoints concerning the availability and commercialisation of natural gas supply in the future. This information has been carried over as an input to this year's analysis.

The methodology, assumptions, and limitations of the study are discussed in the Appendices and should be read to fully understand the context when considering the report's findings and outcomes. The study only considered gas that gets delivered through the transmission network. Additional gas supply and demand may occur outside the network but is not considered here. Also, the study does not consider specific changes in the midstream gas sector, nor is it an assessment of policy or regulatory changes, economic impacts, or wider environmental impacts.

This report does not make any recommendations on a course of action, nor does it make any representations for any of the gas industry stakeholders.

Section 3

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 a possible future state. These scenarios are not an attempt to predict the most likely future, but rather they allow comparison of the complex interactions and impacts of different decision pathways, and enable rich discussion. We note that alternative scenarios could be considered, however, for practicality, the scenarios were selected by Gas Industry Co. to explore the currently relevant range of uncertainties. Scenario narratives and the assumptions therein were developed with Gas Industry Co. over the course of several workshops.

The first three scenarios were considered within a quantitative framework. These three scenarios are:

- ***Low intervention:*** This scenario tests a future where supply continues to be challenged and there is little intervention to develop further supply or incentivise fuel-switching. As a result, some of the major industrial consumers elect to shut down or leave New Zealand. The key consideration within this scenario is the level of disruption caused by a lack of security within the energy sector.
- ***LNG import:*** This scenario tests a future where LNG is imported to help resolve current and forecast domestic supply constraints, opening the door to higher demand within the electricity and petrochemical sectors. The key considerations within this scenario are the higher emissions associated with imported LNG relative to domestic natural gas, and the potential for higher energy costs. These higher energy costs may be limited to those consumers who require flexibility in their demand, or it may permeate through to the entire market. The nuances of these two possibilities are considered within the ***LNG import (split market)*** and ***LNG import (single price)*** scenarios, respectively.
- ***Methanex exits immediately:*** This scenario tests a future where the largest consumer of gas exits abruptly, with production ceasing by the end of 2025, causing a major change to the supply-demand balance. Because of Methanex's role in underwriting supply side development, its exit causes a considerable drop in supply. Large consumers on the demand-side are assumed to collaborate and set the contracts needed to underwrite supply-side development. The assumption that a consortium of large consumers would be able to work together to underwrite supply side development, thereby filling Methanex's current role, may be optimistic. It is important to note that the "Methanex exits immediately" scenario does not reflect Methanex's stated intent and is not a forecast of Methanex's operations. Instead, this hypothetical scenario is intended to explore the impact of an un-signalled exit of the largest consumer in the market.

Overview

A fourth scenario was considered within a qualitative framework. This scenario is:

- ***High renewables:*** This scenario considers a future where an optimised transition is found from our current energy sector to one that is highly renewable. The renewable fuels that replace natural gas (along with other fossil fuels) include solar, wind, hydro, geothermal, wood pellets, biomass, biogas, and green hydrogen. This scenario has a long-term focus and is highly desirable from an environmental perspective. However, due to the different physical characteristics of natural gas as a fuel (and the technologies that use it) compared to, for example solar, it is challenging to quantify how much the uptake of solar power can reduce demand for natural gas. The same challenges exist for other renewable fuels, to varying degrees.

The reason for considering the fourth scenario within a qualitative, rather than quantitative, framework is because it relies on a range of decisions and events that sit outside the purview of the gas sector. The fact that renewables, combined with new technology, can provide alternatives to natural gas is well established. To date, the transition in New Zealand has been focused on reducing coal use and electrifying transport. Switching demand away from natural gas has yet to gain momentum. Historically, reductions in natural gas demand have been driven by supply availability. The costs, particularly in New Zealand's electricity market, and timing of implementing these alternatives remains uncertain. A quantitative picture of this scenario is possible, but it would necessarily involve a wider remit in the depth and breadth of analysis. Here we establish a high-level scope for the required analysis to support this transition.

The time horizon of these scenarios is out to 2050. Due to the current shortfall, the sector sits at a cross-roads and has material decisions to make in the short-term. Nonetheless, a long-term focus is required to reach the best outcome. The scenarios considered here do not represent the only possible outcomes and some decisions, such as Methanex closure, may be reversible, whereas others may not be.

Demand and supply inputs:

In each of the three quantitative scenarios, demand has been categorised into six major components:

- ***Electricity***, which is further split into subcomponents depending on their role within the electricity sector:
  - Peaking – highly flexible, fast-start generation. Typically used to meet rapid variations in electricity demand.
  - Baseload – highly efficient, slow-start generation. Typically used to meet seasonal variations in electricity demand.
  - Dry year reserve – back-up generation that is required when the hydro lakes run low.
- ***Cogeneration*** – gas that has the dual purpose of generating electricity and creating heat for industrial processes.

- ***Petrochemical***, which is further split into subcomponents,
  - Methanex – the methanol production trains Motunui 1 & 2 and Waitara Valley.
  - Ballance Agrinutrients – a domestic fertiliser and urea manufacturer
- ***Industrial*** sector demand (including agriculture, forestry, and fishing but excluding petrochemical)
- ***Commercial*** sector demand
- ***Residential*** sector demand

Similarly, supply has been categorised into five major components:

- ***2P supply*** – quantities of gas that are “proven” and “probable”, considered the best estimate for gas reserves.
- ***2C supply*** – quantities of gas that may be recoverable in the future but are not commercially recoverable at present.
- ***Hydrogen*** – a potential alternative source of energy. This study only considers hydrogen consumed through the transmission and distribution networks. Other hydrogen consumption, outside the network, may also be possible.
- ***Biogas*** – a renewable alternative to natural gas that can be produced from organic material through anaerobic digestion.
- ***LNG*** – liquefied natural gas that can be imported, provided the necessary infrastructure can be developed.

Demand and supply are split into these components because the drivers for change in each component are generally unique among the different components. The different drivers for each component are discussed within the following scenario descriptions.

Demand and supply outcomes:

New within this year's study, demand reductions have been categorised into two components:

- Closure – where the demand reduction is estimated to occur because a consumer is either reducing, or shutting down, operations.
- Fuel switching – where the demand reduction is estimated to occur because a consumer is switching to an alternative fuel source.

Closure and *fuel-switching* are outputs of the modelling. They are a function of input assumptions around the economics of fuel switching within end-use categories (low-temperature space heating, medium-temperature cooking, high-temperature process heat, etc). The purpose of this modelling methodology is to provide insights and enable richer discussion around the evolution of industrial and commercial activity in New Zealand while the country achieves its climate objectives. Separating the demand reduction into these two components provides an important lens through which one can view these scenarios. The methodology for distinguishing between closure and fuel switching relies on assumptions around the timing for when the economic case for switching fuels becomes positive, which depends on the end-use application. The methodology is high-level, and its limitations are outlined in the Appendix. Demand reduction for gas-fired electricity generation and cogeneration has not been separated into these components due to uncertainties in how to categorise this.

Supply shortfall is an outcome within these scenarios. It is categorised according to severity: either demand response (DR) could bridge the gap, or the shortfall would exceed DR capability. These are shown as:

- Supply shortfall (DR available).
- Supply shortfall.

The estimate of DR capability hinges primarily on whether Methanex continues to consume gas. If Methanex continues to consume gas, the maximum DR capability is assumed to mean Methanex is running at a minimum operating level. If Methanex is already running at minimum operating level, or not at all, DR capability is estimated to be effectively zero.

The appearance of supply shortfall has different implications for the sector depending on when it appears in the horizon. In the short term (less than 5 years, say), supply shortfall is likely to mean exactly that – unmet demand and the risk of closures. In the longer term, however, supply shortfall has a less clear meaning. It may still mean unmet demand and risk of closures but could also provide an opportunity and motivation for fuel switching, renewable alternatives, new technology or development of prospective domestic natural gas reserves. The outcomes over this longer-term horizon are likely to be dependent on the focus of government and economic drivers. While in all scenarios, the opportunity for these outcomes to be climate-focussed is possible, it is discussed in depth in the High renewables scenario.

Low intervention - Demand

Scenario demand assumptions:

In the low intervention scenario, the demand forecast is dominated by the closure of industrial facilities, and lower gas demand from within the electricity sector. The assumptions made in this scenario are detailed below. The relative change in demand within each component is depicted in Figure 7, and the demand forecast (in PJ) is presented in Figure 8.

In the petrochemical sector, it is assumed that **Methanex** closes Motunui 2 this year, and operates Motunui 1 through until the end of its current gas supply contract (2028), however, some of its demand is curtailed during supply shortfalls. It is assumed that Waitara Valley does not reopen.

It is assumed that **Ballance** completes stage one of its decarbonisation programme by 2028, reducing its demand by 17%. Stage two begins in 2036, and it eliminates natural gas from its production process by 2051.

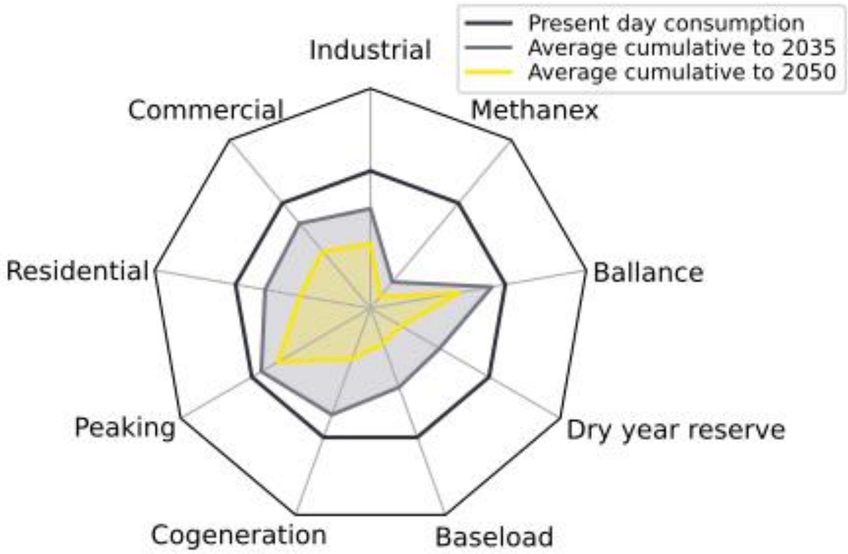


Figure 7: Radar chart depicting time-weighted average demand in the *Low intervention* scenario, normalised to present-day within each component.

Gas-fired **baseload** and **peaking** electricity generation is estimated based on the MBIE Electricity Demand and Generation Scenarios (EDGS) environmental scenario, which has the lowest demand for gas-fired generation of the EDGS scenarios.[23]

It is assumed that gas-fired **cogeneration** plants operate at 80% of their historical capacity and retire 10 years earlier than their estimated project lifetime.

Gas for **dry year reserve** is assumed to be required to provide one third of a 3 TWh dry-year shortfall until 2030. It is assumed that gas is no longer required to provide dry year reserve after 2030, as alternative fuels and technologies come into the stack.

Low intervention - Demand

Due to the supply shortfall, **industrial** consumers are assumed to make significant cuts to their demand. The scale of these cuts exceeds their demand for low temperature end-uses, and they therefore cut back on high-temperature end-use as well. The economics of fuel switching for high-temperature end-use means many close.

Commercial consumers are also assumed to reduce their demand in response to the supply shortfall, with a 50% reduction in low temperature space heating and a 40% reduction in water heating by 2035.

Residential consumers are assumed to reduce their demand rapidly, with a 60% reduction in low temperature space heating and a 40% reduction in water heating by 2035.

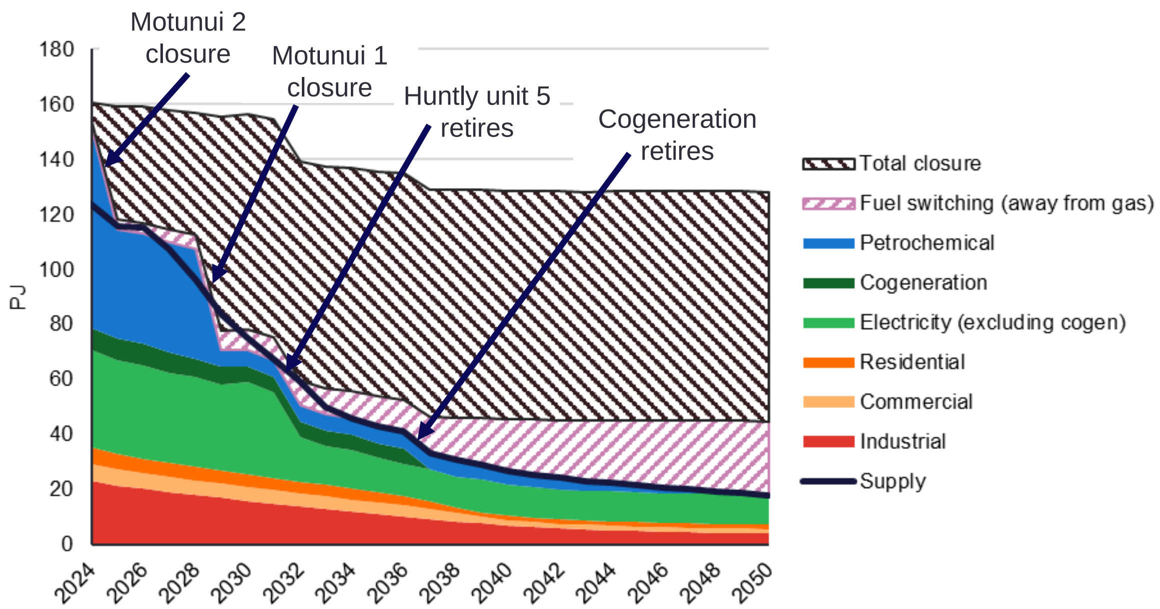


Figure 8: Forecast demand for each sector out to 2050. The navy line shows the forecast supply, while the striped regions indicate industrial and commercial closure or fuel switching. Where the demand is larger than the supply, a supply shortfall exists.

Low intervention - Supply

Scenario supply assumptions:

In the low intervention scenario, the supply side forecast is characterised by supply shortages in the next few years, with little investment in developing any supply sources, including 2C resources, importing LNG, or introducing future fuels such as hydrogen. The assumptions made in this scenario are detailed below. The supply side forecast is presented in Figure 9.

The forecast production profiles for the **2P reserves** for each field are taken directly from MBIE,[12] with the exception of Kupe, which has been updated to reflect a recent material write down of its reserves.[13] We note that these profiles have changed since the 2023 forecasts, with a total drop of 40 PJ in 2025, and 13 PJ in 2030.

It is assumed that high gas prices give rise to some production from **2C resources**, with 30% of 2C resources brought online, excluding Kupe, where no production from 2C occurs. Uncertainty on the demand side delays production from 2C resources until 2030.

Biogas production is assumed to increase slowly over time, with around 0.3 PJ of biogas supplied to the pipeline from all sources in 2030, increasing to 2 PJ in 2035, and 5 PJ in 2050.

For **hydrogen**, in this scenario it is assumed that the regulatory and investment requirements to supply hydrogen to the pipeline are not met, and no hydrogen enters the pipeline.

With little investment in gas solutions, it is assumed that no **LNG** import infrastructure is built, and no LNG enters the pipeline.

Scenario supply and demand findings:

A **supply shortfall** of approximately 30 PJ is estimated to occur in this scenario, for the coming year. Methanex is assumed to reduce its demand by closing one of its methanol trains, which mostly limits further supply shortfalls, with small shortfalls estimated to occur in 2027 and 2028. Demand response from Methanex would be available to meet the shortfall, however this comes with a reduction in their output. Once Methanex leaves the market, there is no further supply shortfall.

While supply shortfalls are estimated to end in 2028, this is due to the amount of **closures** and **fuel switching** on the demand side (Figure 8, p26). Possible closure of industry and commercial consumers is estimated to account for approximately 80 PJ per year of reduced demand from 2030 onward. Estimated demand reduction from fuel switching grows steadily from approximately 7 PJ per year in 2030 to 11 PJ per year in 2035, and 27 PJ per year in 2050.

Low intervention - Supply

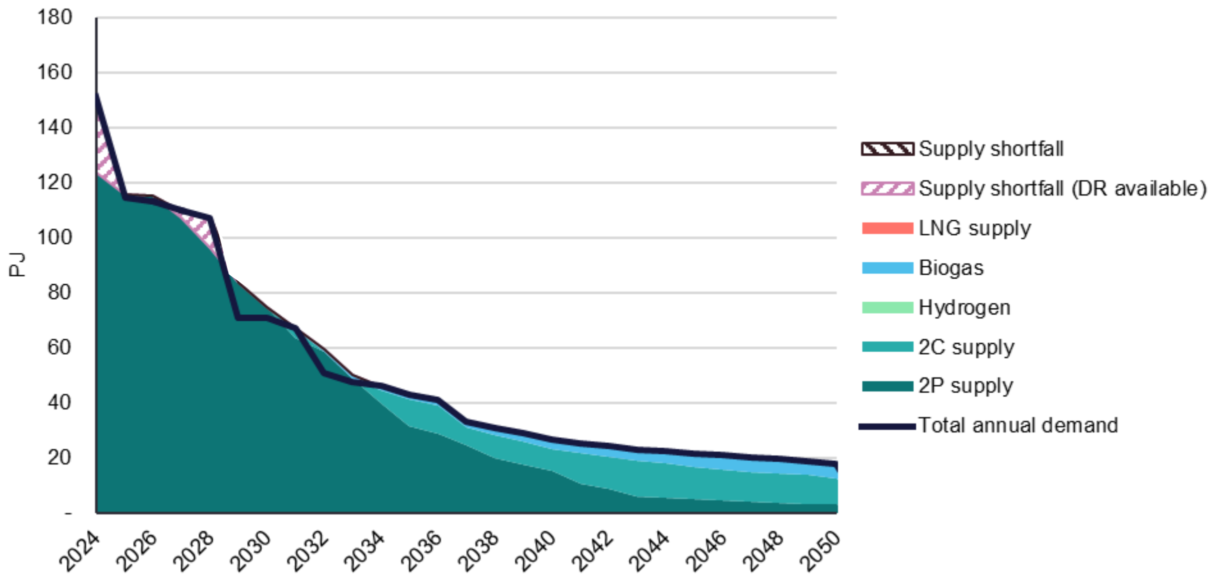


Figure 9: Forecast supply from each source out to 2050. The navy line shows the forecast demand, while the striped regions indicate types of supply shortfall. “DR available” is shortfall where demand response (primarily through Methanex) is able to cover the difference.

LNG import - Demand

Scenario demand assumptions:

In the LNG import scenario, the demand side forecast shows continued high demand, with particularly high demand for gas-fired electricity generation. Over time, demand gradually decreases, mainly due to fuel switching away from gas. The assumptions made in this scenario are detailed below. The relative change in demand within each component is depicted in Figure 10, and the demand forecast in PJ is presented in Figure 11.

In the petrochemical sector, it is assumed that **Methanex** closes Motunui 2 this year, and continues to operate Motunui 1 as long as there is domestic gas supply to meet its minimum demand requirements. From the mid-2030s, it is estimated that its production is frequently curtailed due to supply deficits. Waitara Valley does not reopen.

It is assumed that **Ballance** completes stage one of its decarbonisation programme in 2029, reducing its demand by 17%. In 2042, Ballance begins stage two of its programme in 2042, reducing its demand by approximately 60% by 2050.

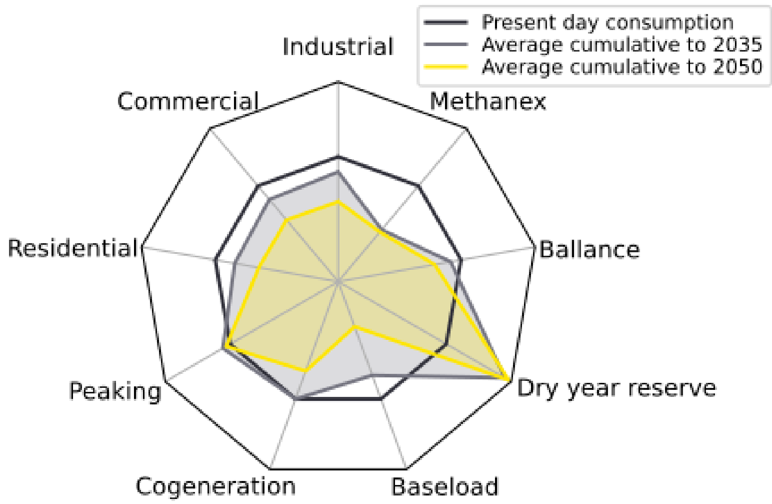


Figure 10: Radar chart depicting time-weighted average demand in the *LNG import* scenario, normalised to present-day within each component.

Gas-fired **Baseload** electricity generation is estimated from the EDGS reference scenario, while **peaking** electricity generation is estimated from the EDGS growth scenario.[23] It is assumed that gas-fired **cogeneration** plants operate at their historical capacity and retire at the estimated project lifetime.

Gas for **dry year reserve** is assumed to be required to provide half of a 3 TWh dry-year shortfall until 2030. Coal retirements in 2031 mean gas use to cover a dry-year shortfall increase to 100% of the 3 TWh required. Over time, it is assumed that this decreases back down to providing half of the shortfall demand in 2050, as alternative technologies come into the mix.

LNG import - Demand

Industrial consumers are assumed to make some cuts to their demand, as options for fuel switching become available. Gas demand reduces as low-temperature heating switches away from gas, and a ~25% reduction in high-temperature heat occurs.

Commercial consumers are assumed to reduce their demand, with a 40% reduction in low temperature space heating and a ~25% reduction in water heating by 2035.

Residential consumers are assumed to reduce their demand, with a 45% reduction in low temperature space heating and a 30% reduction in water heating by 2035.

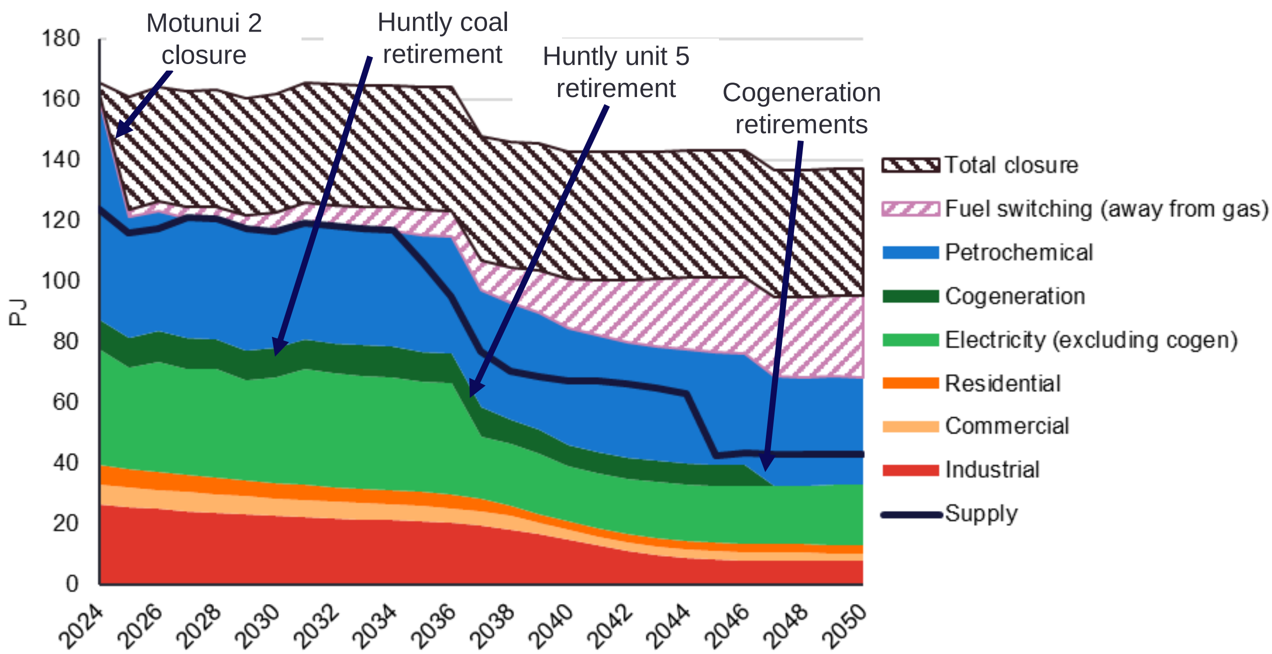


Figure 11: Forecast demand for each sector out to 2050. The navy line shows the forecast supply (from the *split market* option), while the striped regions indicate industrial and commercial closure or fuel switching. Where the demand is larger than the supply, a supply shortfall exists.

LNG import - Supply

Scenario supply assumptions:

In the LNG import scenario, the supply side forecast is characterised by a supply shortfall through till 2026, which prompts investment in new gas supply solutions. LNG imports (beginning winter 2026) and 2C resources are expected to meet demand until the mid 2030s, when supply shortfalls are likely to reemerge. The assumptions made in this scenario are detailed below. The supply forecast is presented in Figure 12, with two different supply side market sensitivities.

The forecast production profiles for the **2P reserves** for each field are taken directly from MBIE,[12] except for Kupe, which has been updated to reflect a recent material write down of its reserves.[13] We note that these profiles have changed since the 2023 data, with a drop of 40 PJ in 2025, and 13 PJ in 2030.

Biogas production is assumed to increase over time, with around 1 PJ of biogas supplied to the pipeline from all sources in 2030, increasing to 5 PJ in 2035, and 15 PJ in 2050.

For **hydrogen**, in this scenario it is assumed that the increased investment in gas gives rise to the blending of hydrogen in the pipeline, which provides up to 0.4 PJ per year.

LNG imports are assumed to begin in winter 2026. Initially LNG is assumed to only be available for the electricity sector to provide dry-year reserve. As domestic supply from certain fields (specifically Kapuni, Mangahewa, McKee, and Kupe) decreases, LNG supply increases to the level of gas demand required for peaking generation. These fields were chosen because stakeholders of these fields also own gas-fired peaking generation, i.e. they are vertically integrated. Electricity generators can pass on increased costs to their consumers which make them more likely candidates to use LNG. Dry-year reserve and peaking generation were chosen because these demand components are highly variable, making LNG well suited as a flexible supply option.

Around the interplay between **LNG** and **2C** supply, we explored two supply side market sensitivities.

- The first option is a ***split market***, where ringfencing around LNG supply (to supply dry year demand in the short term) means customers who use domestic supply are shielded from high prices. In this case, domestic **2C production** is less stimulated. 2C resources are brought online to service demand outside of the ringfencing, with around 50% of 2C resources brought online.
- The second option is a ***single price***, where the gas price is set by the marginal supplier. The higher prices lead to more investment in **2C resources**, which brings 50% of 2C resources online (in a shorter time frame than the split market option). The higher levels of 2C conversion means these resources outcompete LNG until the early 2030s, meaning no LNG is imported until 2033 (apart from a small amount in 2026). This raises a potential stranded-asset risk. However, the option to use LNG acts as an insurance policy, primarily for dry year cover, and caps the price at which Methanex would offer DR into the market.

LNG import - Supply

The underlying cause for having a ***split market*** versus a ***single price*** may be due to having two different products in the market (i.e. a flexible source of supply in LNG and a firm source of supply in domestic natural gas) or it may be due in part to potential policy settings. It is beyond the scope of this study to address this underlying cause.

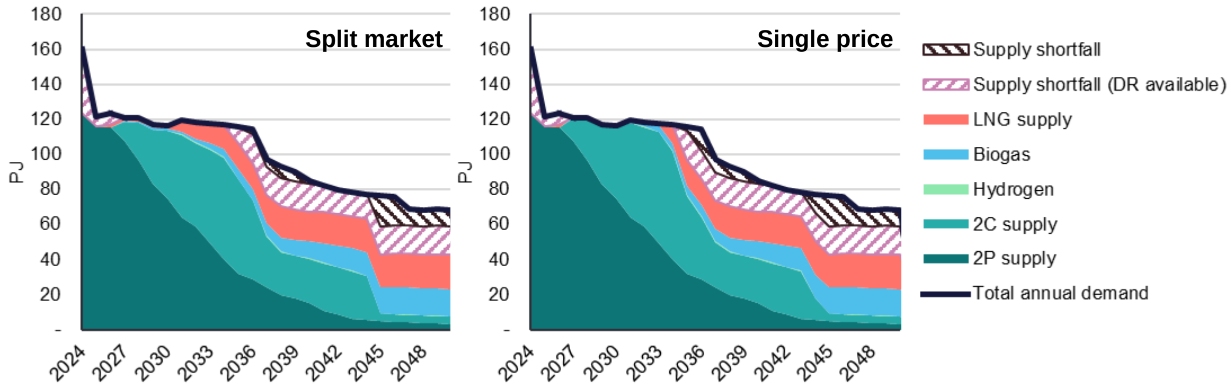


Figure 12: Forecast supply from each source out to 2050. The navy line shows the forecast demand, while the striped regions indicate types of supply shortfall. "DR available" is shortfall where DR (primarily through Methanex) is able to cover the difference.

Scenario supply and demand findings:

A **supply shortfall** of approximately 40 PJ is estimated to occur in 2024, with a smaller shortfall (approximately 5 PJ per year) persisting for the two years following (Figure 12). Demand response from Methanex would be available to meet the shortfall, however this comes with a reduction in its output. While LNG imports and increased 2C investment meet demand until 2035, after this it is estimated that there will be a persistent supply shortfall. Much of this supply shortfall could be mitigated by Methanex flexing their demand, however this would curtail their production significantly. This persistent shortfall may also be met by prospective domestic natural gas.

On the demand side, this scenario has lower risk of **closures** compared to the other scenarios considered, with **fuel switching** accounting for a large portion of the demand reduction in the medium- to long-term (Figure 11, p30). Risk of closure is mostly due to shortfalls in the next year or two and Methanex closing one of its methanol trains. The trend for closures is estimated to be stable, reaching around 40 PJ of closures in the next few years and keeping constant for the forecast horizon.

Methanex exits immediately - Demand

Scenario demand assumptions:

In the Methanex exits immediately scenario, the demand side is dominated by the closure of Methanex, removing the largest consumer from the market. In the wake of its departure, demand from other sectors is assumed to remain high. The assumptions made in this scenario are detailed below. The relative change in demand within each component is depicted in Figure 13, and the demand forecast in PJ is presented in Figure 14.

In the petrochemical sector, it is assumed that **Methanex** decides to leave with little notice period, shutting down Motunui 1 & 2 over the next year. Waitara Valley stays closed.

Ballance is assumed to complete stage one of its decarbonisation programme in 2028, reducing its demand by 17%. In 2036, Ballance begins stage two of its programme, and they eliminate natural gas from their process by 2044.

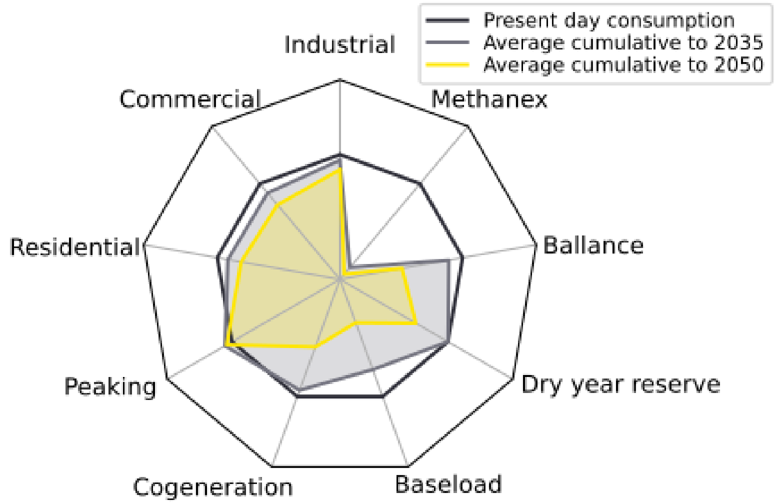


Figure 13: Radar chart depicting time-weighted average demand in the *Methanex exits immediately* scenario, normalised to present-day within each component.

Gas-fired **Baseload** electricity generation is estimated from the EDGS growth scenario, while peaking electricity generation is estimated from the EDGS reference scenario.[23]

It is assumed that gas-fired **cogeneration** plants operate at 90% of their historical capacity and retire 5 years earlier than the estimated project lifetime.

Gas for **dry year reserve** is required to provide half of a 3 TWh dry-year shortfall until 2030. This amount is estimated to decrease over time, until gas is no longer required to provide dry year reserve by 2050.

Demand from **industrial** consumers is assumed to decrease gradually over time, as options for fuel switching become available, with a significant proportion of low-temperature processes switching away from gas. High- and medium-temperature processes are assumed to remain reliant on natural gas, leading to an overall forecast of high demand from industry.

Methanex exits immediately - Demand

Commercial consumers are assumed to take some opportunities for fuel switching and reduce their overall demand, with a 30% reduction in low temperature space heating and a ~9% reduction in water heating by 2035.

Residential consumers are also assumed to take some opportunities for fuel switching and reduce their demand, with a ~40% reduction in low temperature space heating, but no reduction in water heating.

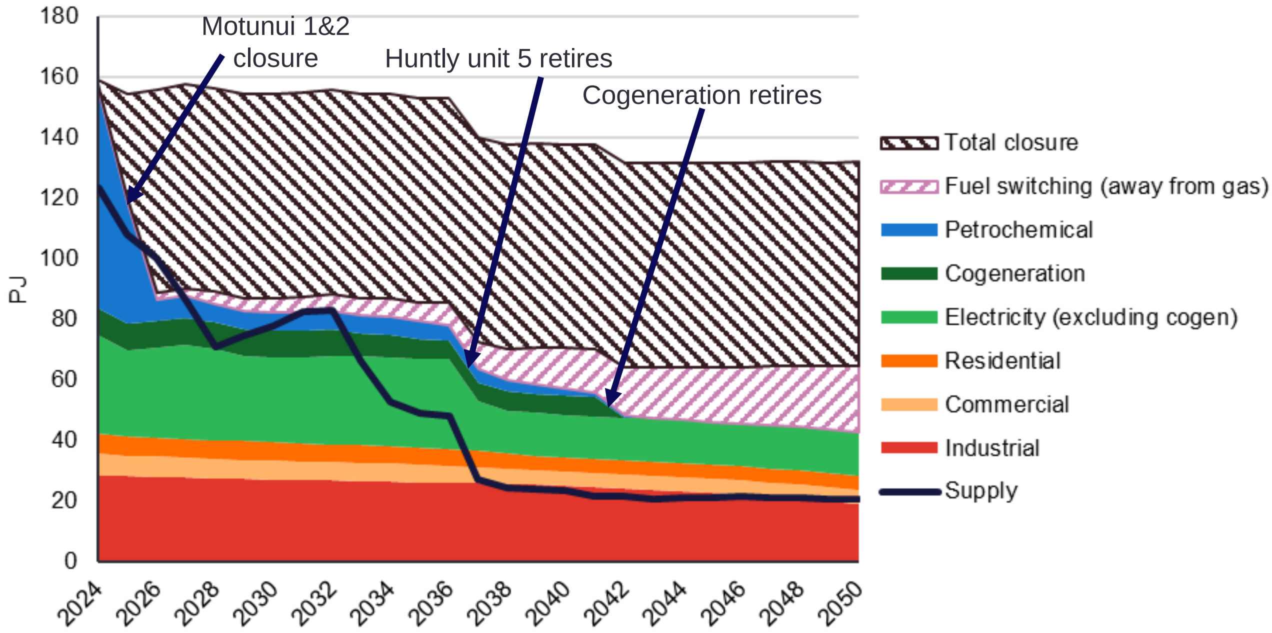


Figure 14: Forecast demand for each sector out to 2050. The red line shows the forecast supply, while the striped regions indicate industrial and commercial closure or fuel switching. Where the demand is larger than the supply, a supply shortfall exists.

Methanex exits immediately - Supply

Scenario supply assumptions:

In the Methanex exits immediately scenario, the supply side forecast is characterised by long-term supply shortages, where the mechanisms for mitigating this impact are unclear. The assumptions made in this scenario are detailed below. The supply forecast is presented in Figure 15.

With a decrease in demand from Methanex closing, the supply side responds with a reduction in production from the **2P reserves**. Forecast production profiles are adjusted to tend toward 1P reserves over time, a 40% drop in production by 2030. These profiles are adjusted from the original forecasts from MBIE,[12] with the profile for Kupe again having been updated to reflect a recent material write down of its reserves.[13] We note that these profiles have changed dramatically since the 2023 forecasts, with a drop of 40 PJ in 2025, and 13 PJ in 2030.

It is assumed that limited investment and low demand leads to only 20% of **2C resources** being brought online.

Biogas production is assumed to increase over time, with around 1 PJ of biogas supplied to the pipeline from all sources in 2030, increasing to 5 PJ in 2035, and 15 PJ in 2050.

For **hydrogen**, in this scenario it is assumed that the regulatory and investment requirements to supply hydrogen to the pipeline are not met, and no hydrogen enters the pipeline.

With little investment, no **LNG** import infrastructure is built, and no LNG enters the pipeline.

Scenario supply and demand findings:

A **supply shortfall** of approximately 30 PJ is estimated to occur this year, lowering to 0 PJ in 2026 as Methanex exits the market. Small supply shortages reappear in 2028 to 2030 (on the order of approximately 7 PJ), and are persistent after 2033, increasing to around a 30 PJ per year shortfall. With Methanex no longer in the market, the supply shortfalls from 2028 onwards are unable to be met by demand response. The mechanism of mitigating these lasting shortfalls is unclear, with outcomes ranging from closures and unmet demand, to action on alternative technologies and renewable fuels.

On the demand side, it is estimated that there is a significant risk of closures, and some fuel switching takes place (Figure 14, p34). The demand reduction from closures is mostly related to Methanex demand, resulting in a 70 PJ per year reduction from 2026 onwards. This is lower than the long-term closure amount in the Low intervention scenario, as it is assumed that Methanex's exit allows supply to meet the demand of other large users for longer. This scenario has the lowest amount of fuel switching, growing steadily over time to result in approximately 5 PJ per year of demand reduction in 2030, 6 PJ in 2035, and 22 PJ in 2050.

Methanex exits immediately - Supply

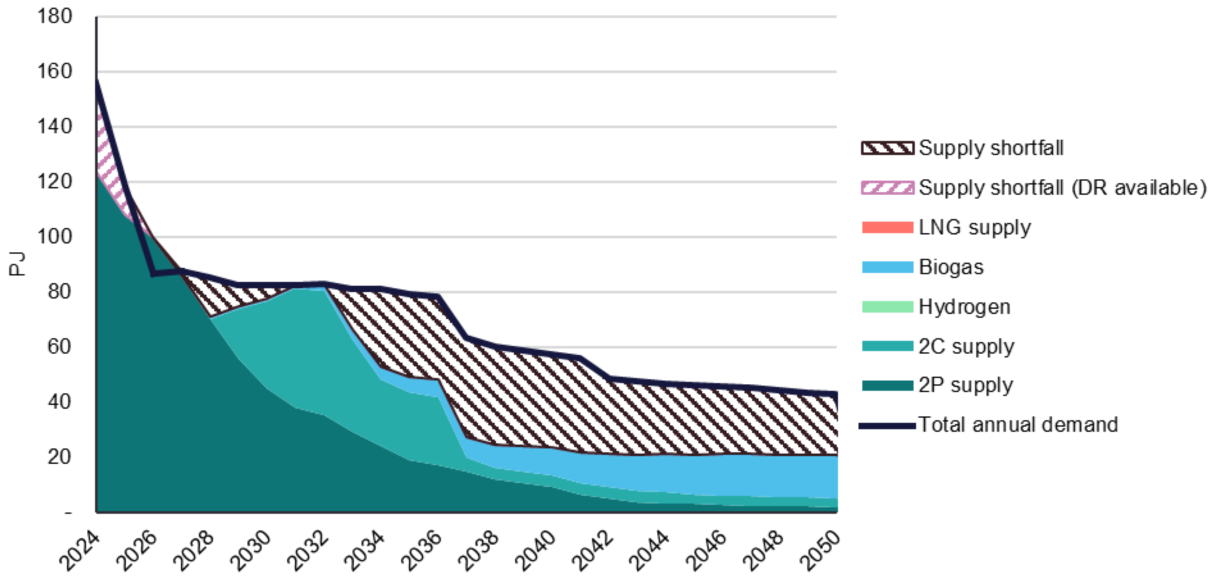


Figure 15: Forecast supply from each source out to 2050. The red line shows the forecast demand, while the striped regions indicate types of supply shortfall. “DR available” is shortfall where demand response (primarily through Methanex) is able to cover the difference.

High renewables

While in the short term, the current gas supply headwinds are likely to set the scene, in the longer term, the focus is more likely to be around climate change response, particularly regulatory initiatives. The three previous scenarios tested different decision pathways that respond to the estimated shortfall in the short term. This scenario discusses the longer term, how the gas sector may be impacted and how the sector may support climate outcomes, predicated on the Climate Change Response (Zero Carbon) Act, which sets a framework for New Zealand to develop and implement policies that support the global initiative under the Paris Agreement to limit warming to 1.5 °C.

The *High renewables* scenario seeks to explore how the gas sector may be impacted and support these longer-term climate outcomes. However, given the significant uncertainties and dependencies outside of the gas sector, quantitative modelling of this scenario is beyond the scope of this report, and so this scenario is only explored qualitatively.

What could a High renewables scenario look like in New Zealand?

The energy sector currently contributes approximately 48% of total net emissions or 37% of total gross emissions.[37] Most energy sector emissions come from liquid fuels and coal. Approximately one quarter of the sectors emissions come from natural gas. That means natural gas contributes around 12% of the total net emissions or 9% of total gross emissions.[37]

Around the world, natural gas is often promoted as a transition fuel. There are arguments that countries that are highly dependent on coal can reduce their emissions by switching to natural gas. The argument that natural gas could play this role in New Zealand has struggled to gain wide acceptance. What is clear is that natural gas is currently an important source of energy for many businesses and households, and therefore coordinating the reduction of natural gas emissions requires careful planning.

In a *High renewables* scenario, it is assumed that energy demand is met increasingly by renewables (including both renewable electricity and other renewable energy sources). As a result, it would be expected that natural gas use would decline over time as users switch to these renewable energy sources. However, the degree and the rate at which this switching occurs will differ by application, and for some users it may not be technically or economically viable to switch to renewable options in the short-term. To continue to supply gas to these users without compromising on climate commitments, a High Renewables scenario also needs to consider how to reduce emissions of remaining natural gas production. Some of the potential features of a High Renewables scenario could include:

Biogas

Biogas could create a direct fuel-switching option, allowing some users to continue to consume gas with little impact on operations or supporting infrastructure. However, technical, regulatory, and economic barriers exist for biogas, including the availability of feedstock and associated lifecycle emissions, could limit the role biogas is able to play in providing an alternative to natural gas at scale.[38]

Hydrogen

Production of hydrogen through electrolysis requires significant amounts of renewable energy, and while there is significant interest in hydrogen globally, the technology is still in the early stages of development, and the economics over the long term are highly uncertain. There are also technical limitations on how hydrogen can be used in existing infrastructure (e.g. transmission pipelines) which could limit its ability to offset natural gas demand in the current network without significant upgrades.[26] There is potential for hydrogen to be used outside of the gas network, either as a feedstock or energy source, but this would require the development of a market for these 'green' products, and for production costs to be reduced to a level that the market would be willing to pay for them.

Renewable electricity

Fuel switching from natural gas to electricity could be a technically and economically viable option for some gas users, particularly over the medium-term as existing assets reach end of life. However, achieving this on a large scale requires investment on both the demand side (e.g. electric boilers, furnaces and heat pumps) and the supply side (e.g. renewable generation, firming, transmission and distribution). As the penetration of renewables in the grid increases, there is also potentially an important role for gas to play in firming and dry-year support in at least the short- to medium-term.

CCUS

While Carbon Capture, Utilisation and Storage (CCUS) is not renewable, given the emissions reduction driver for this scenario it could play a role in reducing both upstream and downstream emissions for the gas remaining in the system. For upstream emissions, this could involve re-injection of CO_2 from extraction. For downstream emissions, this would likely be limited to sites where CO_2 is already separated, or otherwise easily captured, and there is access to suitable storage. Depleted gas fields could provide potential storage options, however in both the upstream and downstream cases, an appropriate regulatory regime to incentivise and manage CCUS would likely be required.

Renewable heat

In some applications, renewable sources of heat (e.g. biofuels, geothermal heat, solar thermal technologies, etc) could be used to replace or supplement the use of gas for process heat. This would likely require significant changes to existing processes and in some cases could also mean co-location with the renewable resource (e.g. geothermal field). These applications would likely be customised to specific sites and applications, and so technology availability (demand and supply side) and economics would be key considerations in understanding the potential for renewable heat to play this role. Other factors which would need to be considered include sources and availability of feedstock (e.g. for biofuels) and lifecycle emissions.

Potential benefits and uncertainties of a High Renewables scenario

A key driver, and benefit, of the High Renewables scenario is the ability to support New Zealand's climate commitments. In the other scenarios considered in this report there are varying degrees of potential industrial closures which would also lead to reductions in emissions. In these scenarios, the closure of industry will have an impact on the economy. However, in a *High renewables* scenario it is assumed that some of these closures could be avoided through a higher degree of fuel-switching to renewable energy sources. This means that, in addition to supporting climate commitments, the *High renewables* scenario could deliver economic benefits through retaining existing industries, and possibly helping to attract new ones. However, the ability of these benefits to be realised is highly dependent on the economics of fuel switching, which have not been analysed in detail in this report.

As well as enabling fuel switching to renewable energy sources, a *High renewables* scenario would also be expected to define the role of gas in supporting the energy transition over time. In the short term, this could include identifying which applications have economic options for fuel switching, while maintaining supply for users without a current alternative (potentially leveraging upstream CCUS to minimise emissions in the process). Gas also has the potential to support the wider energy transition by providing firming and dry-year support for intermittent electricity generation over the medium-term as other technologies become available to increasingly take over this role in the longer-term.

While a High Renewables scenario offers significant potential benefits, there are critical uncertainties which would need to be further analysed to understand the degree to which these benefits could be realised. As noted above, the economics of fuel switching is a key uncertainty which would vary greatly between applications and would need to consider requirements on both the demand side (e.g. availability of technologies) and the supply side (e.g. capacity of renewable energy supply). Reducing gas demand could also have economic costs, including costs of decommissioning gas infrastructure and potential impacts on users who are unable to switch to renewable alternatives.

High renewables

The rate of transition would also be a key consideration in a *High renewables* scenario. Moving too fast has a risk of resulting in a significant economic impact and industrial closures, while moving too slow could limit the benefits (economic and environmental) of this scenario. While this scenario is more focussed on long-term outcomes, short-term security of supply would still need to be addressed to ensure industry is able to remain long enough to transition to renewable energy sources. However, it is important that decisions taken to address short-term security of supply do not compromise New Zealand's ability to achieve this longer-term success.

The uncertainties associated with a *High renewables* scenario extend beyond the gas sector. Enabling gas users to switch to renewable alternatives, and enabling the supply side to support this transition, would require fostering the right wider environment through coordination of key stakeholders within, and outside of, the gas sector, including:

Policy & Regulatory

Potential roles:

- Carbon price (NZ ETS).
- Renewable energy certificates.
- Recognise CCUS.
- Financial or other incentives/ penalties.
- Target setting.

Upstream gas sector

Potential roles:

- Eliminate fugitive emissions of methane.
- Become net zero in operations.
- Lead investment in nascent, low-emissions technologies.
- Support and facilitate CCUS.

Midstream gas sector

Potential roles:

- Eliminate fugitive emissions. through better monitoring.
- Enable pipeline hydrogen.
- Support and facilitate CCUS.

Downstream gas sector

Potential roles:

- Improve energy efficiency.
- Switch to renewable alternatives.
- Employ CCUS.
- Enter into long term supply agreements to underwrite investment in renewable energy.

High renewables

Renewables and electricity sector

Potential roles:

- Partner with the downstream sector.
- Accelerate investments in renewable technologies and capacity.
- Minimise costs of supply to support fuel switching.

Financial sector

Potential roles:

- Employ specialist knowledge in the energy sector.
- Develop green financial products to help finance renewables.
- Invest in infrastructure that advances the transition.
- Support incumbents to restructure and transform.

Over time, the economic drivers for switching to renewables are expected to improve through increased costs of non-renewable energy (e.g. through increases in carbon prices) and reduced costs of renewable alternatives. However, delivering the *High renewables* scenario would likely require additional measures to accelerate this transition by improving the economic case for switching from where it stands today. This would need to be balanced with other national climate initiatives (particularly those with potentially lower costs of abatement) and to ensure NZ industry remains competitive internationally (e.g. international carbon prices, EU Carbon Border Adjustment Mechanism, etc.).

Given the degree of uncertainty outside of the upstream (supply) and downstream (demand) gas sectors, a detailed analysis (qualitative or quantitative) of a *High renewables* scenario is beyond the scope of this report. As described, this scenario has the potential to deliver benefits to both the gas sector (through providing a transition pathway) and the wider economy (through supporting national climate commitments while limiting industrial closures and even potentially attracting new industries). However, better understanding the likelihood and potential pathways to achieving these benefits would require detailed qualitative and quantitative analysis to assess the potential benefits, associated costs and uncertainties across the gas sector, energy sector, and wider economy.

Section 4

Modelled outcomes

Energy security – Shortfall and closures

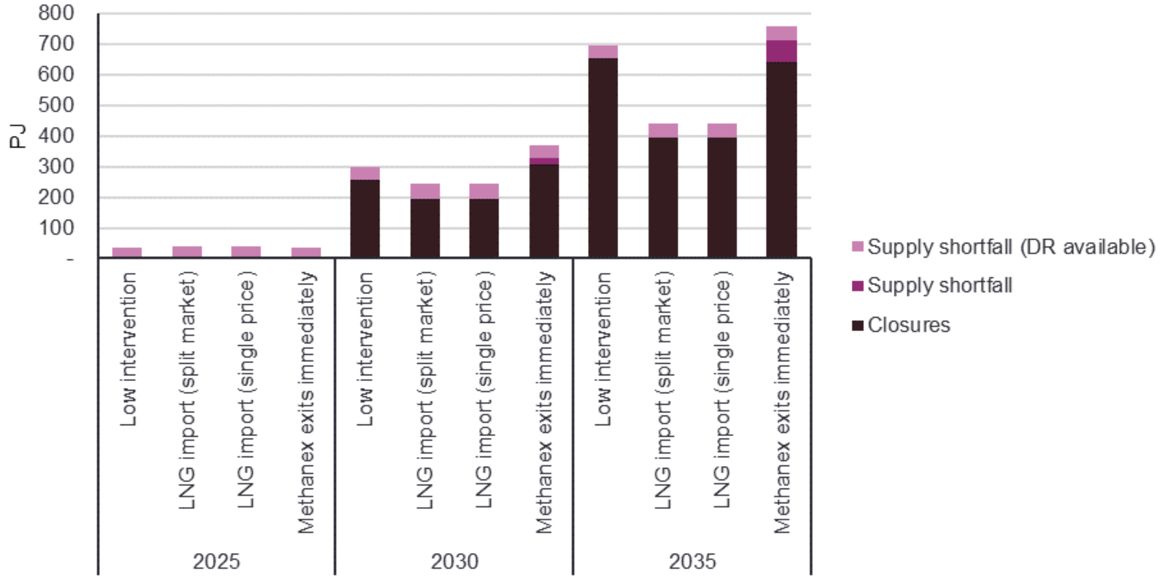


Figure 16: The cumulative amount of unsupplied natural gas demand in each scenario, from now until 2025, 2030, and 2035.

Energy security is discussed here in the context of curtailed or unsupplied demand over time (Figures 16 (cumulative) and 17 (per annum, 2035)). Lack of energy security leads to three potential outcomes:

- Closures – where either the energy price, or the lack of availability of gas, means industrial and/or commercial operators permanently shut down their operations.
- Supply shortfall (DR available) – where there is insufficient supply to meet demand, but industry (particularly Methanex) provides demand response (DR) to cover the difference.
- Supply shortfall – where there is insufficient supply to meet demand, and industry is unable to provide DR to cover the difference. The inability to provide DR is driven either by industrial closure (once an industry has closed, it can no longer provide DR) or by the scale of DR required. For this outcome, the mechanism of mitigating this shortfall (alternate fuels or technologies, further closures, etc) is unclear.

Low intervention: In this scenario, the lack of energy security manifests as industrial closure and supply shortfall. The fact that Methanex stays in the market until the end of 2028 means that DR is available for much of the supply shortfall. The risk of closure or exit of industrial players (excluding Methanex) is estimated to result in a reduction of 16 PJ of demand in 2035 (Figure 17). This accounts for approximately 50% of the present industrial gas consumption. This is the highest level of industrial closure risk estimated among the three quantitative scenarios.

LNG import: In this scenario, LNG bolsters security within the energy sector. Some shortfall still occurs and risk of closures still exists, however, energy security is improved, with this scenario having the lowest total shortfall and closure risk compared to the *Low intervention* and *Methanex exits immediately* scenarios. Estimated industrial closures reduce natural gas demand by 7 PJ in 2035 (Figure 17), which is a 25% decrease from present industrial gas consumption.

Methanex exits immediately: In this scenario, the lack of energy security manifests as industrial closure, primarily through the closure of Methanex. Without Methanex, the availability of DR is reduced, and security of supply in the electricity sector is challenging, particularly in a dry year. This scenario results in the lowest risk of industrial closure for users other than Methanex (Figure 17), however, this scenario also has the highest amount of supply shortfall risk with no available DR. The consequences of such shortfall (without DR) are unclear (Figure 16).

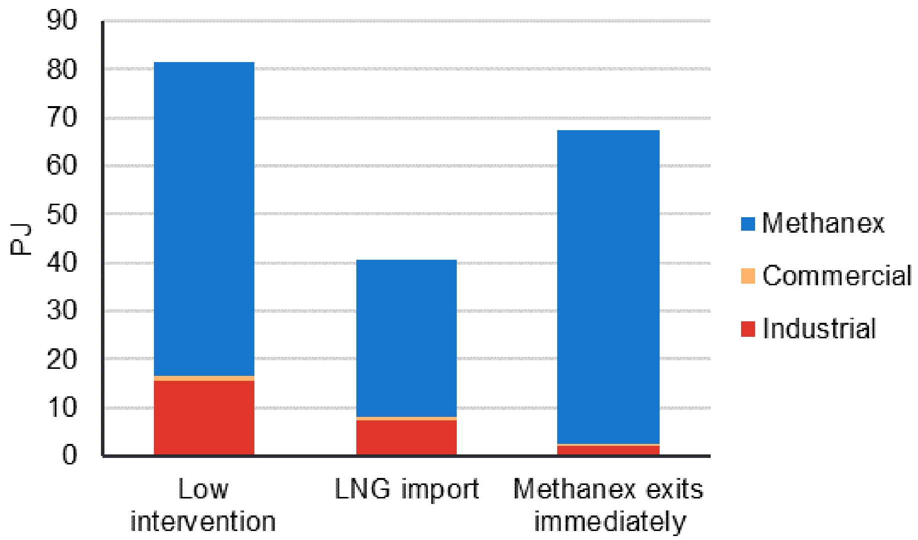


Figure 17: The unsupplied natural gas demand in 2035, due to industrial and commercial closures.

Energy security – Dry year

Understanding the risk of a dry year, and the ability of the gas sector to support electricity generation during such periods, is important in assessing future energy security.

The charts presented in Section 3 show gas demand required to support electricity generation in a dry year as a probability-weighted value, where dry years are assumed to happen approximately once every five years. The required demand for one dry year is spread over this 5-year period. This is appropriate when considering how dry year demand will deplete finite reservoirs, over the whole forecast horizon. However, in practice this demand will need to be supplied over a period of a few months within one year of unknown timing. In Figure 18, the supply forecasts for each scenario are presented, with both the probability-weighted total demand presented, and the maximum demand that could be reached in any year if a dry year were to occur. The methods of supplying this demand differ across scenarios and time, and are dependent on multiple factors, including the availability of storage, infrastructure to import LNG, and the demand response capabilities of the market.

Low intervention

In this scenario it is assumed that gas is required to meet electricity demand in a dry year until 2030, it is assumed that the reduced supply outlook motivates the electricity industry to look elsewhere for dry year security. While Methanex remains in the market (until 2028), there is the possibility that dry year demand could be met by Methanex flexing their demand. Between 2028 and 2030, there is no clear mechanism of meeting this dry year demand.

LNG import (single price) and LNG import (split market)

In both scenarios, it is assumed that the gas required to meet dry year demand increases in 2030, due to the switch away from coal-fired generation, and then decreases slowly, as it is assumed other forms of generation come online. Prior to 2026, when LNG imports start, demand flexing from Methanex would be able to meet dry year demand, while post 2026, LNG would meet this demand.

Methanex exits immediately

In this scenario it is assumed that the gas required to meet dry year demand slowly decreases after 2030. Without Methanex or LNG in the market, it is unclear how dry year demand would be met over the full forecast period.

Energy security – Dry year

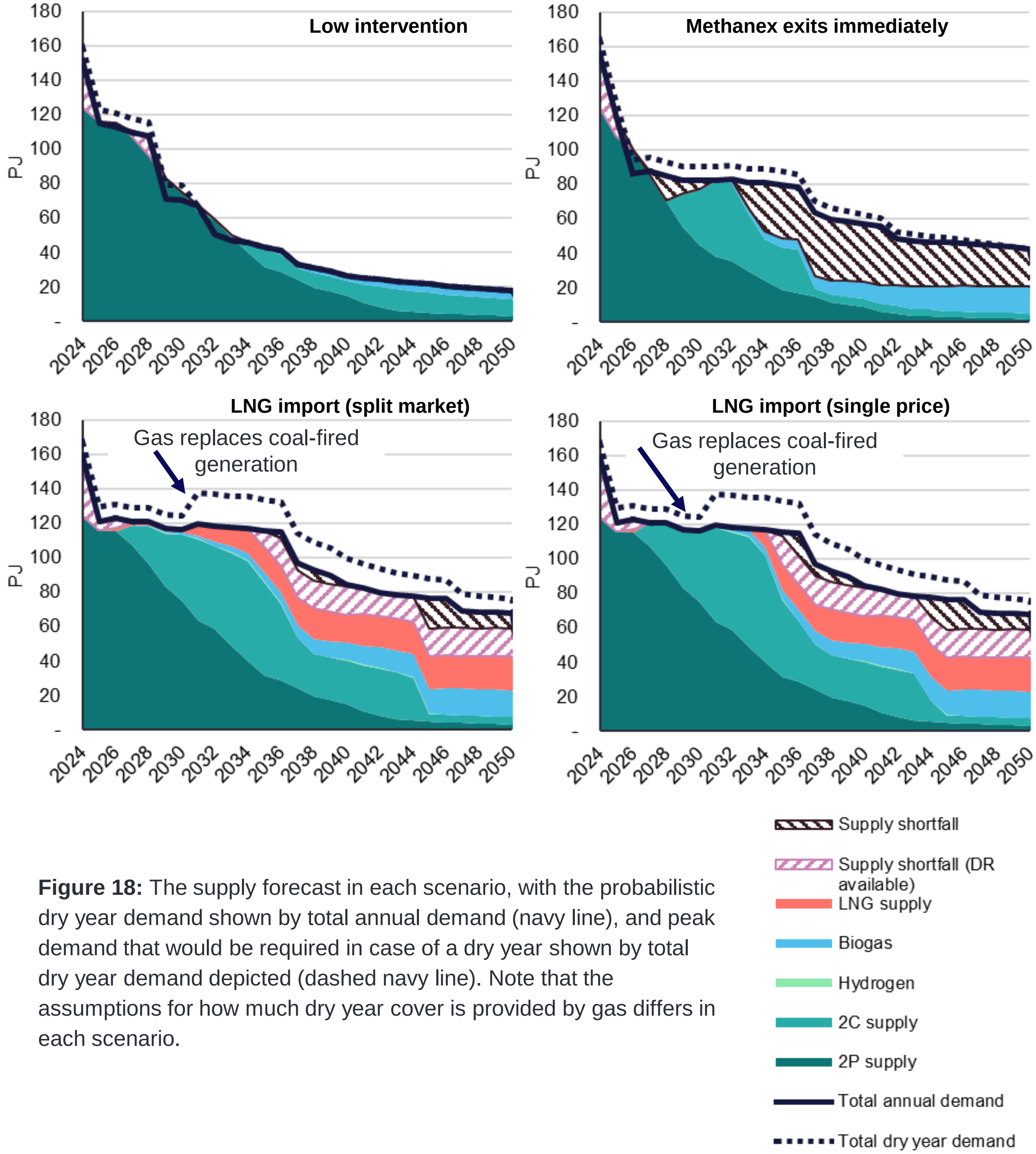


Figure 18: The supply forecast in each scenario, with the probabilistic dry year demand shown by total annual demand (navy line), and peak demand that would be required in case of a dry year shown by total dry year demand depicted (dashed navy line). Note that the assumptions for how much dry year cover is provided by gas differs in each scenario.

Emissions

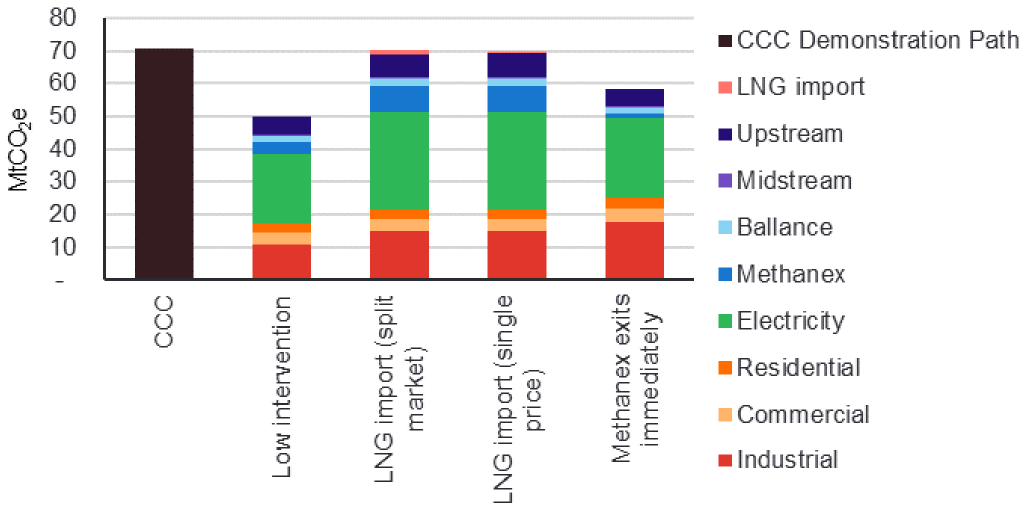


Figure 19: The cumulative emissions in 2035 from all sectors. LNG import emissions include all upstream, import, and regassification emissions.

Figure 19 shows the cumulative emissions in 2035 in each of the three quantitative scenarios. These emissions are shown alongside the demonstration path scenario created by the CCC.[1] We have chosen to show all emissions linked to the domestic use of gas. Emissions are categorised according to where within the industry they occur - LNG import emissions, upstream, midstream, and downstream. Downstream emissions are split further into the sectors where end-use occurs. LNG import emissions take into account all upstream, import, and regassification emissions, which means these values capture more than what is currently included in the NZ ETS.

Given that the emissions shown here are only those linked to the domestic use of gas, there are potential emissions consequences arising from these scenarios that are not captured here. In particular, industrial closures in New Zealand may lead to intensification of industry elsewhere, leading to similar if not higher global emissions.

Low intervention: In this scenario, the supply shortfall and a large number of likely industrial closures are estimated to result in lower emissions than the *LNG import* and *Methanex exits immediately* scenarios, and the CCC demonstration path. Cumulative emissions in this scenario total 50 $MtCO_2e$ in 2035, around 15% lower than the next lowest emissions scenario, *Methanex exits immediately*, and 30% lower than the CCC demonstration path.

LNG import: In this scenario, the sustained demand for gas and the introduction of LNG imports lead to the highest emissions of these scenarios. Cumulative emissions in this scenario total 70 $MtCO_2e$ in 2035 for the ***split market*** variant (with 1 $MtCO_2e$ from LNG import emissions), and 70 $MtCO_2e$ in 2035 for the ***single price*** variant (with 0.4 $MtCO_2e$ from LNG import emissions). The ***LNG import (split market)*** emissions are similar to the CCC demonstration path, and 17% higher than the next highest scenario, *Methanex exits immediately*. The ***LNG import (single price)*** emissions are slightly lower than the ***split market*** variant, due to higher domestic natural gas production.

Emissions

As noted above, the LNG import emissions capture all emissions, rather than just emissions counted in the NZ ETS. Around 30% of the LNG import emissions (on average) would be counted in the NZ ETS.

It is interesting to note that the intensity of emissions related to LNG imports is much higher than those related to domestically producing natural gas, LNG import emissions are around 3 times higher per PJ of gas than the upstream emissions for domestic gas. This means that if LNG supplied more of the market than it is assumed in this scenario (dry year and peaking demand for electricity generation), there would be a material increase in emissions.

Methanex exits immediately: In this scenario, emissions are reduced primarily due to Methanex's closure. Cumulative emissions in this scenario reach 58 $MtCO_2e$. Cumulative emissions in 2035 are around 18% lower in this scenario than the CCC demonstration path.

Prices

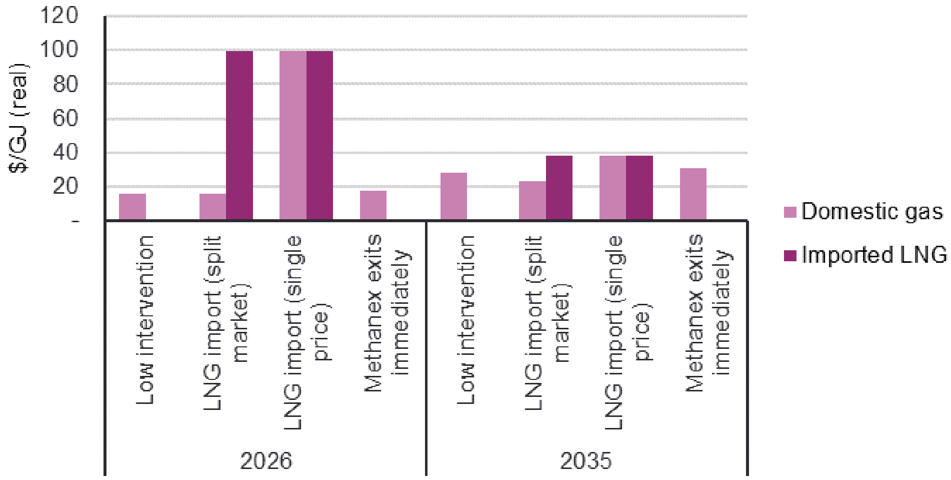


Figure 20: The price per GJ of gas in each scenario, in 2026 and 2035.

Figure 20 shows the natural gas price in 2026 and 2035 in each of the three quantitative scenarios. Where LNG is imported, we show the price of both domestic natural gas and imported LNG. Prices incorporate fixed and variable OPEX and CAPEX costs, carbon costs, and commodity prices (where appropriate).

Low intervention: in this scenario, the natural gas price is estimated to be $16/GJ in 2026, which rises to $28/GJ in 2035. This increase is due to declining volumes, leading to a higher fixed cost component.

LNG import: In the ***LNG import (split market)*** variant, LNG prices are estimated to be $100/GJ and domestic gas prices are estimated to be $16/GJ in 2026. The LNG price falls to an estimated $38/GJ in 2035, while domestic gas prices rise to $23/GJ in the same period. In this scenario, LNG is ringfenced to exclusively supply dry year and peaking demand for electricity generation. It is assumed that electricity generators are willing to pay the LNG price to ensure security of supply, and can pass the costs on to customers. Industrial and commercial users are assumed to be more price sensitive, particularly if there is no avenue to pass the LNG costs on to customers, and they pay the domestic gas price.

In the ***LNG import (single price)*** variant, prices are estimated to be around $100/GJ for all consumers in 2026, and $38/GJ in 2035. These prices are very high. In the ***single price*** variant, the price is set by the marginal supplier, which is LNG. The LNG price is so high due to the limited supply, which leads to a very high fixed cost component. These high prices trigger higher domestic natural gas production.

Methanex exits immediately: In this scenario, natural gas prices are estimated to be $17/GJ in 2026 and rise to $31/GJ by 2035 due to declining volumes and higher fixed cost component. This price increase is similar (but slightly smaller) than the increase seen in the *Low intervention* scenario.

Prices

It is assumed within this modelling that prices are determined by costs, essentially through a long-run marginal cost model or levelized cost of energy. This approach has limitations, for example during times of scarcity where prices can significantly exceed the cost of production. Also, we note that the pricing of LNG will depend on the commercial model and may potentially reflect short-run marginal costs, with sunk-costs excluded or covered through other arrangements.

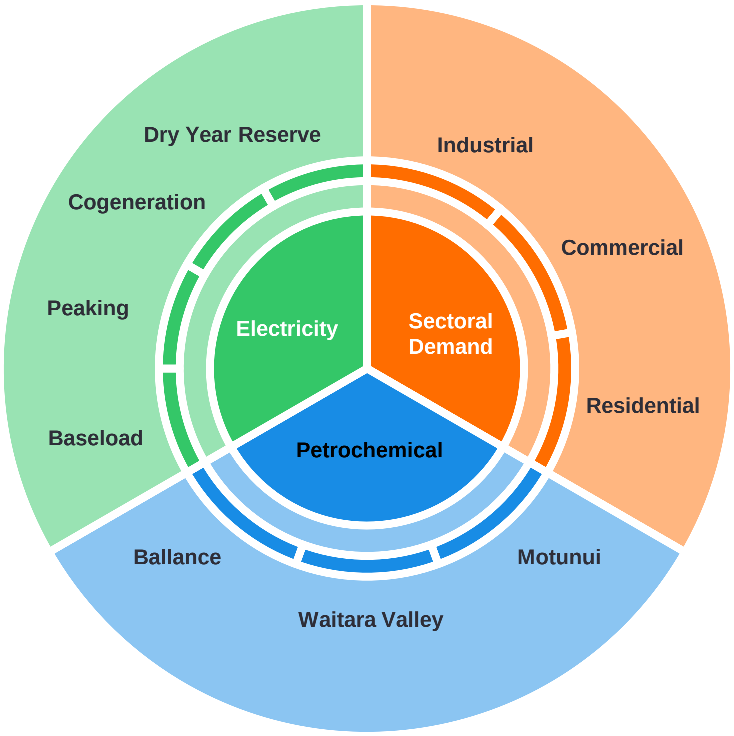
Section 5

Appendices

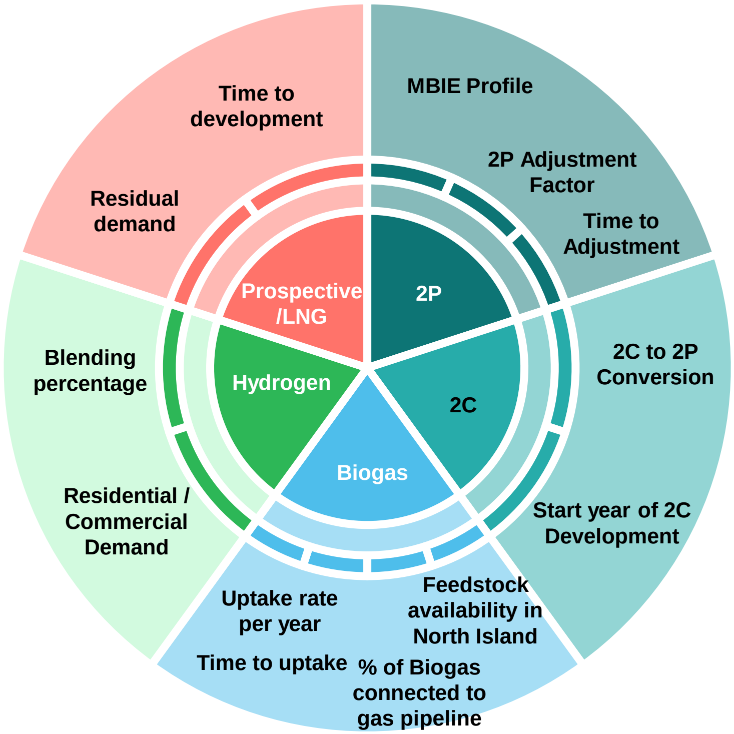
A high-level overview of our gas sector model

In these appendices we present an overview of the gas sector model, including the general methodology, assumptions, and limitations. For a complete description of the modelling suite, please refer to the 2023 Supply and Demand Report.[2]

Demand Model



Supply Model



Model Output Assessment

Energy Security	Emissions	Gas Price
Security criteria based on: Switchable and baseload demand cover 2P and 2C supply cover	**Detailed modelling of value chain emissions:** Upstream/field emissions from flaring and venting Midstream fugitive emissions Process emissions form petrochemical demand Combustion emissions from upstream, midstream and downstream Biogas/hydrogen emissions Pre- and post-combustion CCUS	**High level price trend analysis based on gas sources:** Indigenous supply and impacts of fixed costs versus variable costs Biogas/hydrogen supply costs LNG import and netback costs Carbon impost

The modelling suite is tuned to high level analysis of the NZ gas supply and demand system. Within the tool a series of choices can be made to tailor scenarios to user need. The flexibility and transparency allows for scenarios that can be interrogated at multiple levels to drive insight.

Sectoral model (including industrial closures)

Forecast methodology:

The forecast methodology of the sectoral demand model is described in the previous year's report.[2] In summary, separate statistical regression models are fit to historical data for the industrial (excluding petrochemical), commercial, and residential sectors. This regression model provides insight into the current trend and volatility in the data. The forecast in each scenario is informed by the regression model, but it is not determined by it.

The forecast in each scenario is determined through a set of assumptions around the level of short-term and long-term demand reduction in end-use applications which are broken down into categories: high temperature heat, medium temperature cooking, medium temperature process heat, low temperature space heating, low temperature water heating, or low temperature other. A structural break separates the two forecast horizons. The short-term reduction is generally assumed to occur by 2035, although this can be varied within the model. The long-term reduction sets the asymptotic limit of the Bass-diffusion model, which describes the tipping point to exponential decrease later in the horizon, after the structural break.

By comparing the assumed level of demand reduction with the result of the regression model, a percentile from the regression model can be selected. This determines the forecast in the short-term. In the long term, a Bass-diffusion model is determined that bridges the actual value and slope of the demand at the initial point (the end of the short-term) and the long-term assumption as an asymptotic limit.

Methodology to distinguish between fuel switching and closure:

The methodology to distinguish between switching and closure operates through the breakdown between categories. Specifically, the incremental reduction in each year of the forecast is broken down in terms of a certain amount of reduction within each category. Each category has an assumed propensity to fuel-switch that varies depending on the year of the forecast. For example, a drop in low-temperature-end-use demand in 2024 is likely to be due to fuel-switching rather than closure. However, a drop in high temperature end use demand in 2024 is likely to be due to closure rather than fuel switching. The forecast of switching and closures in each scenario is therefore determined by the assumed timing at which it becomes economic to fuel-switch. If a demand reduction is forced to occur prior to this time, it will show as closure.

Limitations of our approach:

The methodology relies on assumptions for the level of demand reduction within end-use categories and the economics of fuel-switching. While the assumptions were chosen to be logically consistent within the scenario narrative, they do not represent the only choice, and other possible assumptions could have been chosen. We have not studied alternative assumptions and doing so may lead to different outcomes and key findings.

The methodology does not explicitly account for changes in regulatory settings or other levers that may be pulled within the sector.

Table A1: The existing breakdown across end-use categories.[27]

Category	Industrial	Commercial	Residential
High temp heat	55.6%	0.0%	0.0%
Med temp heat cooking	0.8%	9.1%	3.8%
Med temp heat process	15.8%	0.0%	0.0%
Low temp heat space	2.1%	76.4%	55.5%
Low temp heat water	14.5%	10.8%	40.7%
Low temp heat other	8.4%	0.0%	0.0%
Other	2.8%	3.7%	0.0%

Assumptions:

The table below shows the amount of demand reduction assumed in the short and long term, split by end-use category across the three scenarios. The numbers show the percentage of reduction, so higher numbers represent lower demand. The actual demand within an end-use category is calculated through the existing breakdown and the reduction according to:

$$d_e(YYYY) = b_e(2023) \times (1 - r_e)$$

Where $d_e(YYYY)$=demand in end-use '*e*' in year *YYYY*, $b_e(2023)$=existing breakdown in end-use '*e*' (taken from Table A1), and r_e=reduction in end-use *'e'* (taken from Table A2, p55). The short-term reduction is assumed to apply in 2030 in the *Low intervention* scenario and 2035 in all other scenarios.

The charts shows the assumptions for fuel-switching economics in each year of the forecast horizon. The number varies between 0 and 1, where:

- 0 means no fuel switching, entirely closures.
- 1 means entirely fuel switching, no closures.

These assumptions are based around existing studies, including from the Energy Efficiency & Conservation Authority, and the International Energy Agency.[28,29,30]

Sectoral model (including industrial closures)

Table A2: The assumed reduction in end-use demand in each sector in the short and long term.

Sector	End-use category	Methanex exits immediately	LNG import	Low intervention	Methanex exits immediately	LNG import	Low intervention
		Short term assumption			Long term assumption		
Industrial	High temp heat	0%	24%	40%	60%	70%	90%
Industrial	Med temp heat cooking	0%	0%	0%	0%	0%	0%
Industrial	Med temp heat process	10%	40%	80%	75%	80%	80%
Industrial	Low temp heat space	25%	25%	25%	80%	85%	90%
Industrial	Low temp heat water	50%	50%	50%	80%	85%	90%
Industrial	Low temp heat other	50%	50%	50%	80%	85%	90%
Industrial	Other	0%	0%	0%	80%	85%	90%
Commercial	High temp heat						
Commercial	Med temp heat cooking	0%	0%	0%	0%	0%	0%
Commercial	Med temp heat process						
Commercial	Low temp heat space	30%	40%	50%	50%	80%	95%
Commercial	Low temp heat water	9%	26%	43%	20%	40%	60%
Commercial	Low temp heat other						
Commercial	Other	0%	0%	0%	0%	0%	0%
Residential	High temp heat						
Residential	Med temp heat cooking	0%	0%	0%	0%	0%	0%
Residential	Med temp heat process						
Residential	Low temp heat space	37%	45%	60%	50%	80%	95%
Residential	Low temp heat water	0%	30%	40%	20%	40%	60%
Residential	Low temp heat other						
Residential	Other						

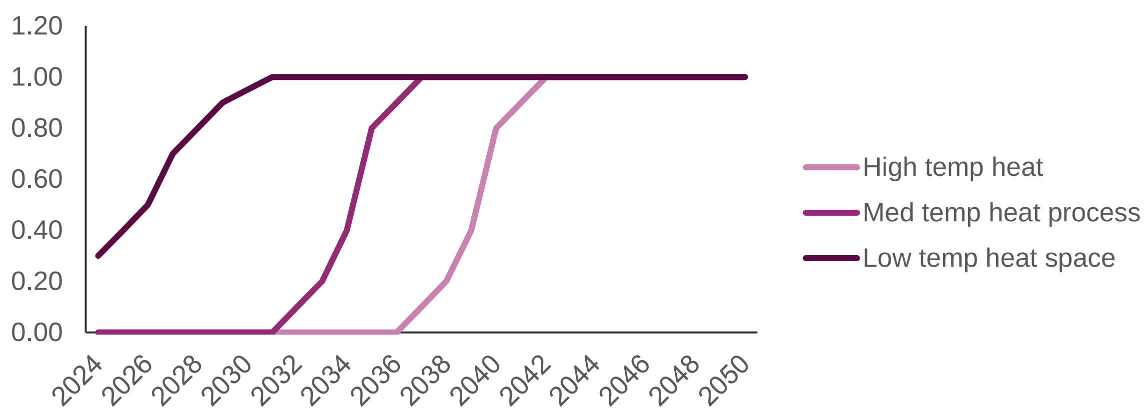


Figure A1: The assumed economics of fuel switching for each end-use category in each year of the horizon.

Forecast methodology:

The gas-fired electricity generation demand is based on the recent Electricity Demand and Generation Scenarios (EDGS) published by MBIE.[23] The purpose of those scenarios is to explore potential future electricity demand and the required generation capacity. The scenarios are used by Transpower in their proposals to the Commerce Commission to upgrade the transmission network. The scenarios explicitly quantify the estimated volume of gas required by the electricity sector for baseload and peaking purposes.

The cogeneration demand is based on historical demand for cogeneration at Kinleith, Whareroa (Hawera), Kapuni, and Glenbrook. An assumed derating is applied to the historical demand in each scenario. The cogeneration plants are assumed to retire at a date based on their expected operating lifetime. The cogeneration assumptions take into account the proposed ban on new fossil-fuel baseload electricity generation.[31]

Additional demand for gas during a dry hydrological year (when hydro generation is lower than expected) is estimated based on a ***minimum requirement*** that gas provide the remaining supply after coal, demand-response, and national conservation campaigns have been applied.

Limitations of our approach:

The methodology relies on assumptions made in the MBIE EDGS, derating and retirement assumptions for cogeneration, and dry year gap/frequency. While the assumptions were chosen to be logically consistent within the scenario narrative, they do not represent the only choice, and other possible assumptions could have been chosen. We have not studied alternative assumptions and doing so may lead to different outcomes and key findings.

The methodology does not explicitly account for changes in regulatory settings or other levers that may be pulled within the sector.

Assumptions:

Dry year assumptions are outlined in Table A3 and cogeneration assumptions are outlined in Table A4.

Electricity model

Table A3: Dry year demand assumptions.

Source of supply	Dry year shortfall of ~3.2 TWh	Detailed assumption
Coal fired generation	~1.5 TWh	700 MW (i.e. all 3 Huntly Rankine units) running 24 hours a day for 90 days
Demand response (Tiwai primarily)	~0.5 TWh	Reduced 205 MW (per Tiwai's demand response contract) running 24 hours a day for 90 days
Demand response (National conservation campaign)	~0.2 TWh	5% of the national demand (~6000 MW) will be reduced for 30 days
Gas fired generation	~1 TWh	450 MW (i.e. Huntly Unit 5 and Huntly Unit 6) running 24 hours a day for 90 days

The extra gas demand needed during a dry year results in approximately 1 TWh of additional electricity generation from natural gas, which corresponds to about 10 PJ of gas

Reducing Methanex's consumption is the simplest solution to provide this extra gas. Methanex uses ~ 0.19 PJ per day, so if they were to operate at 50% capacity for 90 days, it could free up around 9 PJ to support gas-fired generation

In a scenario where Methanex has exited, meeting this natural gas demand becomes highly uncertain and likely becomes significantly more challenging. Other sectors would have to bear the impact, for instance, Tiwai might need to be fully shut down, or national conservation campaigns would have to be required to a greater extent.

Table A4: Cogeneration gas demand and plant retirement assumptions.[31]

Cogeneration plant	Scenario	Derating	Retirement date
Glenbrook	LNG import	0%	2047
	Methanex exits immediately	10%	2042
	Low intervention	20%	2037
Kapuni	LNG import	0%	2040
	Methanex exits immediately	10%	2035
	Low intervention	20%	2030
Whareroa	LNG import	0%	2038
	Methanex exits immediately	10%	2033
	Low intervention	20%	2028

Supply model

The supply model methodology is described in detail in last year's report.[2] In summary, the method produces supply profiles for natural gas (2P reserves and 2C resources), biogas, hydrogen, and LNG, matched to demand. Detailed assumptions are described in the following section.

Natural gas

Key inputs in forecasting natural gas supply include the forecast 2P field output,[12] remaining 2P reserves,[12] remaining 2C resources,[12] the conversion rate from 2C to 2P (with a base assumption of a 50% conversion), minimum and maximum deliverability from each field, outages, and the production profile.

While most field production profiles are sourced from MBIE data, the estimated 2P reserves for the Kupe gas field have been materially reduced this year (from ~160 PJ to ~94 PJ).[13] In this case, the modelled 2P reserves have been reduced to 94 PJ, and the production profile shifted to give the appropriate decline profile.

The forecast 2P output from each field is adjusted for upstream and midstream losses to give the forecast of 2P supply to the pipeline. The 2C resources are forecast subject to the remaining amount of 2C gas available at each field, the maximum deliverability of the field, spare production capacity of the field (dependent on 2P production), and the earliest development year. The amount of 2C gas delivered annually is also limited to the amount required to match demand, after 2P gas, biogas, and hydrogen. In the *LNG import (split market)* this demand matching is also dependent on the LNG supply (see the LNG section below).

Biogas

The forecast of annual biogas output is derived from the expected uptake of biogas production units over time for various biogas production sources. The categories of biogas supply and drivers of said supply (including uptake timing and amount produced) are sourced from the Gas Transition Plan Biogas Research Report.[25]

Hydrogen

Hydrogen is modelled as a blend with natural gas in the pipeline, serving residential and industrial consumers in Auckland and Wellington. Hydrogen is restricted to these residential and industrial consumers as the end use technologies are compatible with hydrogen blended gas. Hydrogen can constitute 20% by volume of a gas blend (equivalent to 6% by energy) with these technologies. The hydrogen forecast is derived from the residential and industrial gas demand in Auckland and Wellington, the blend ratio (above), and the start date of hydrogen supply.

LNG

The LNG supply forecast is matched to demand, with the key inputs being the demand forecast split by sector, the sectors that LNG is ringfenced to supply, the supply start date (when import infrastructure is constructed), and the cargo capacity.

Supply model

The demand matching of LNG supply is modelled in two ways here, to explore the impacts of different market settings. In both the *LNG import (split market)* and *LNG import (single price)* scenario options, LNG supply is limited to the amount required to match demand from the electricity and residential sectors (its "allowed demand"), after 2P, biogas, and hydrogen have been supplied. In the *LNG import (split market)* option, LNG takes priority in fulfilling this allowed demand over 2C, however in the *LNG import (single price)* option, 2C is allowed to fulfil all demand prior to LNG fulfilling its allowed demand.

Limitations:

- While some communication with field operators took place last year, consultation was not extensive or comprehensive, as this report is intended to be a high-level assessment of the industry, as opposed to a detailed, field-specific outlook.
- The natural gas forecasting method is designed to describe whole-of-industry production with the aim of meeting demand. It is not intended to reflect operator plans for field development.
- Biogas uptake of each category is assumed to be linear, which does not account for any changes in efficiency as the scale of biogas production increases. This also does not account for the likely staggered, non-linear nature of uptake as new production units of different sizes are brought online.
- A significant proportion of the assumptions regarding biogas production are sourced from one report, limiting the diversity of information.
- For hydrogen uptake, no changes to end-use technology are assumed, limiting the amount of blending that can occur.
- No minimum or maximum allowable LNG supply is assumed (other than demand matching). Therefore, we assume that LNG import and use is efficient and does not require more storage than is currently available, and that small amounts of LNG (significantly less than one cargo) would still be imported.

Assumptions related to the supply model are listed below for each gas (Tables A5 to A8). Scenario specific assumptions are discussed in the main text of the report (pages 27, 31, and 35).

Table A5: Natural gas supply assumptions, related to both 2P and 2C production.

Category	Assumption	Details
Upstream/ Midstream losses	7.97%	This includes gas reinjected (0%), LPG extracted (3.81%), gas flared (0.89%), production losses and own use (2.83%), and transmission and distribution losses (0.44%). These values are estimated from historical trends.
Outage	5%	Downtime for production facilities for repairs, maintenance, and any unforeseen circumstances.
2P production profiles, remaining reserves, 2C resources		These are from the MBIE reserves data published in January 2024.
Minimum and maximum deliverability from each field		These are based on the MBIE published data, with some updated based on conversation with operators in the course of writing the 2023 Supply and Demand report.
Earliest development year (2C) resources	2027 (most cases)	For most fields this was assumed to be 2027 given lead times on resource consents. For some fields this was assumed to be longer, due to production facility constraints.

Table A6: Biogas supply assumptions. The base biogas assumptions are the same as last year, as there have been no material updates in this time. Refer to last year's report for detailed numerical assumptions.

Category	Assumption	Details
Biogas feedstocks	Municipal biosolids, pre- and post-consumer food waste, municipal green waste, landfill gas, dairy and meat wastewater, horticulture waste, supplementary crops, animal manure, utility crops	These feedstocks are based on the feedstocks identified in the Gas Transition Plan Biogas research report. The amount and timing of uptake of each feedstock is detailed in last year's report.

Supply model

Table A7: Hydrogen supply assumptions.

Category	Assumption	Details
Consumers	Residential and industrial	This was assumed as the blending of hydrogen would not require any upgrades to the distribution network or appliances.
Location	Auckland and Wellington	Blended supply local to the distribution network would only occur in major population centres.
Earliest blending date	2029	A 5-year lead time for the necessary regulatory changes was assumed. Firstgas has announced hydrogen blending trials beginning in the coming months.[32]

Table A8: LNG supply assumptions.

Category	Assumption	Details
Cargo size	4 PJ	This assumption was sourced from the Gas Transition Plan report on LNG imports.[33] The lead time for buying cargoes was not considered, as the modelling is on an annual basis.
Earliest start date	2026	Recent supply pressures and statements from Government has indicated the fast tracking of consents to allow an LNG terminal to be in place by winter 2026.[34]

Pricing model (including LNG prices)

A detailed description of the pricing model is presented in last year's report.[2] Here we provide a general overview of the model, including key inputs and outputs. Wholesale prices are calculated for each source of gas (domestic natural gas, biogas, hydrogen, and LNG), from which volume weighted average annual prices ($/GJ (real)) are derived.

Natural gas price

The natural gas price is derived from a reference natural gas price, sourced from historical MBIE gas price data, with a weighted price factor applied. This factor acts as a multiplier that accounts for the shifts in fixed and variable costs. On top of this, a carbon cost is applied, where the forecasted carbon price (from the CCC demonstration path)[1] is multiplied by the emissions intensity of natural gas consumption.

Biogas price

The biogas price is derived from the weighted average of the costs related to biogas supply divided by the modelled amount of biogas supply for each source of biogas. A carbon cost is also applied to this, using the same method as for natural gas.

Hydrogen

The hydrogen price is obtained from a levelized cost of green hydrogen forecast.[35] No carbon cost is applied, as it is assumed that green hydrogen will be used, which has no associated carbon emissions.

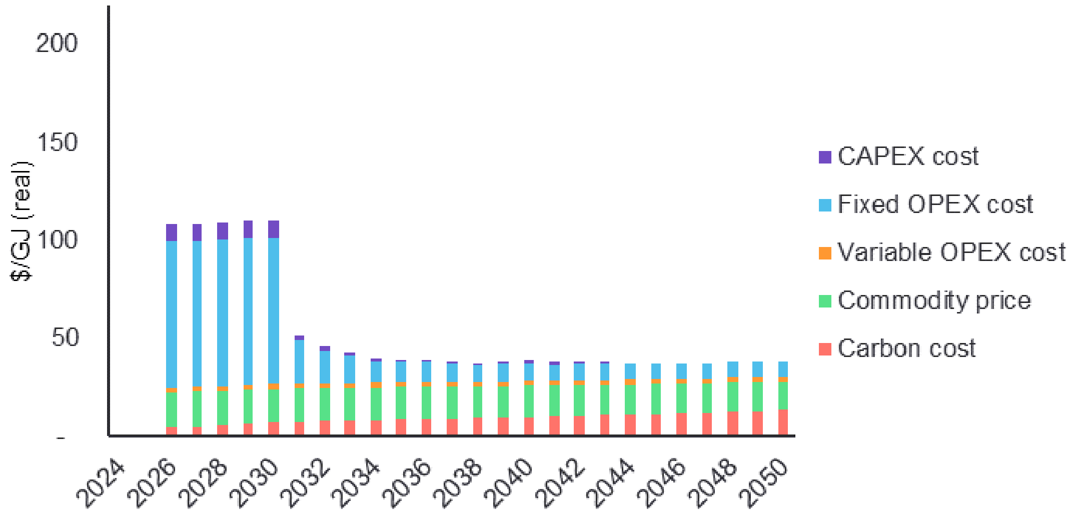
LNG

The LNG price includes costs associated with the wholesale commodity LNG price, fixed and variable operational expenditure costs, capital expenditure costs, and carbon costs. A wholesale commodity LNG price forecast from a NZ Battery project report was used.[36] Operational and capital expenditure costs were sourced from the Gas Transition Plan LNG import report.[33] Some of these values required data processing to annualise the values, with an LNG port payoff life of 20 years assumed, and the longest lifetime (until 2050) of the port assumed. Carbon costs were applied using the same method as for natural gas. An example of the breakdown of the LNG prices into constituent parts is shown in Figure A2, where it can be seen that in years where very little LNG supply is imported (2033, *LNG import (single price)*), the price greatly increases due to a proportionally very high fixed cost component.

Limitations

- The model relies on a limited number of assumptions for each fixed and variable cost component of each respective gas type, reflective of current prices. These parameters would likely change over the horizon of the modelling period.
- The LNG costs are sensitive to the choice of import port and the source country of the LNG.
- The model does not reflect the commercial model of any gas suppliers, and instead reflects the costs a supplier must recover on an annual basis.

Pricing model (including LNG prices)



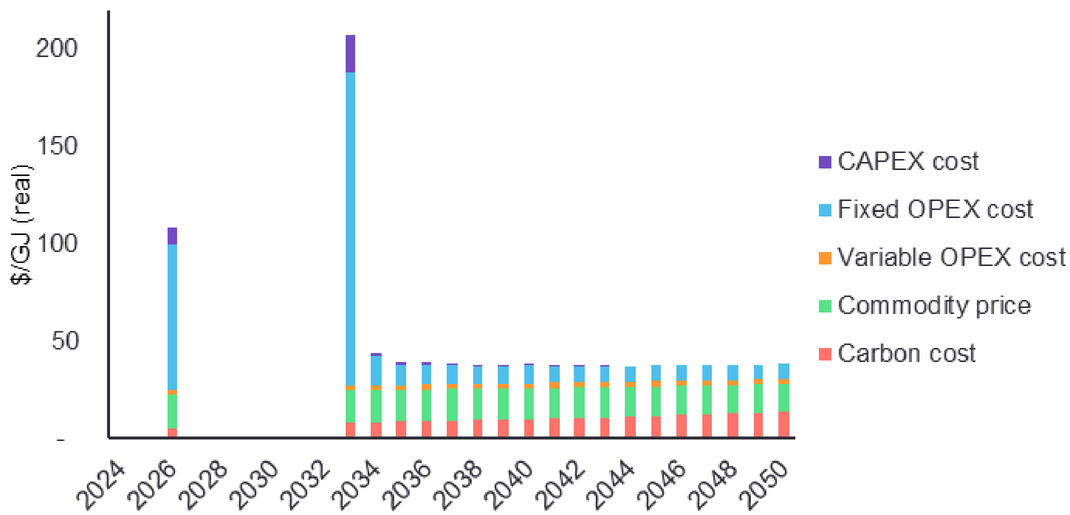


Figure A2: LNG prices over time, split into constituent costs. **Top:** The *LNG import (split market)* option, where a relatively constant amount of LNG is imported annually (see p32, Figure 12). **Bottom:** The *LNG import (single price)* option, where 2026 and 2033 are characterised by very small amounts of LNG imports, due to high amounts of 2C resources being brought online (see p32, Figure 12).

Assumptions related to the price model are listed below for each gas (Tables A9 to A12). Note that for all gas prices, the CCC's demonstration path carbon price forecast was used to calculate the carbon cost.[1]

Pricing model (including LNG prices)

Table A9: Natural gas price assumptions.

Category	Assumption	Details
Reference natural gas price	$10.70	Sourced from an assessment of MBIE gas price data. Assumed to be commodity price only.
Weighted price factor		Consultation with upstream operators (2023 report) gave the baseline assumptions that 64% of the wholesale commodity price consists of fixed costs, while the remaining 36% is related to variable costs. This factor is varied over time, with the variable component dependent on the volume of gas produced, and the fixed component dependent on the operation of major production installation. 2C resources are assumed to have a higher variable cost component (200%) to allow for increased cost of development.
Emissions intensity	55.73 $kgCO_2e/GJ$	Average natural gas emissions intensity, provided by Gas Industry Co.

Table A10: Biogas price assumptions.

Category	Assumption	Details
Cost associated with biogas from each supply source		The cost associated with different biogas supply sources varies based on tranches, sourced from the Gas Transition Plan Biogas research report.[25]
Emissions intensity – Biomethane from Anaerobic digestion	19 $kgCO_2e/GJ$	Sourced from Biogas research report.[25]
Emissions intensity – Biomethane from Landfill gas	10 $kgCO_2e/GJ$	Sourced from Biogas research report.[25]

Table A11: Hydrogen price assumptions.

Category	Assumption	Details
Hydrogen price forecast		Levelized cost of green hydrogen forecast sourced from NZ Hydrogen Scenarios report.[35]

Pricing model (including LNG prices)

Table A12: LNG price assumptions.

Category	Assumption	Details
Commodity price forecast		Base case forecast from NZ Battery Project– Biofuel and LNG cost forecast.[36]
Fixed OPEX	$149.5m /year	Mean of Port Taranaki fixed OPEX cost estimates from Gas Transition Plan LNG import report.[33]
Variable OPEX	$2.52 /GJ	Mean of Port Taranaki variable OPEX cost estimates from Gas Transition Plan LNG import report.[33]
CAPEX	$175m	Mean of Port Taranaki CAPEX cost estimates from Gas Transition Plan LNG import report.[33]
Port pay-off life	20 years	
Port lifetime	Until 2050	Longest lifetime of the options in Gas Transition Plan LNG import report[22] was assumed.

Emissions model

The emissions model methodology is described in detail in last year's report.[2] Emissions ($MtCO_2e$) modelled here are a sum of upstream, LNG import related, midstream, and downstream emissions, with downstream emissions split into the sectors where the gas is used. No use of CCUS has been assumed in any scenario.

We have chosen to represent all emissions related to the use to natural gas in New Zealand. This does not always align with emissions counted in the NZ ETS. In addition, this does not account for emissions generated by other fuels or emissions related to the use of natural gas in other countries. For example, if decreasing use of natural gas leads to the increased use of coal, then the associated change in emissions would not be accounted for in this model. Another example is if the closure of industry in New Zealand leads to an increase in that industry's production in other countries, the associated emissions would not be accounted for in this model.

Upstream

Upstream emissions are calculated using key inputs including a fugitive emissions factor, which includes flaring and venting, a stationary combustion emissions factor, and the total annual production of the field.

LNG import

LNG import emissions include all upstream and midstream emissions related to LNG. Key inputs include the upstream emissions factors, including flaring, venting, production losses, and own use, liquefaction, shipping, and regassification once in New Zealand. Emissions that are likely to be included in the NZ ETS relate to the shipping and regassification, which account for, on average, 30% of the LNG import emissions. It should be highlighted that these emissions intensities will be sensitive to the chosen country of origin and the resulting shipping distance.

Midstream

Midstream emissions calculations factor in the amount of gas passing through the pipeline, a fugitive emissions factor, and a midstream combustion emissions factor, which accounts for the emissions from the compression stations, per unit of production.

Downstream

The key inputs for calculating the downstream emissions are the total gas demand, split by gas type (natural gas, hydrogen, biogas), the emissions factors for different types of gases and end-uses (hydrogen and biogas, stationary combustion, petrochemical processes), and the priority with which sectors have their demand fulfilled by hydrogen or biogas. Downstream emissions are a total of stationary combustion emissions from the relevant sectors, petrochemical process emissions from the petrochemical sector, and hydrogen and biogas emissions from hydrogen and biogas use.

Limitations

- As outlined above, this model only considers the emissions directly linked to the use of natural gas in New Zealand. The outcomes of higher or lower emissions between scenarios may not reflect the trends for all domestic emissions (as these include other fuels), or global emissions.

Assumptions related to the emissions model are listed below for each emissions source (Tables A13 to A16).

Table A13: Upstream emissions assumptions.

Category	Assumption	Details
Fugitive emissions factor	3.34 $ktCO_2e/PJ$	Derived from gas emissions data from MBIE.[24]
Stationary combustion emissions factor	54.05 $ktCO_2e/PJ$	From Ministry for the Environment guidelines on measuring emissions.[37]
Total annual natural gas production		Output of the supply model.

Table A14: Midstream emissions assumptions.

Category	Assumption	Details
Fugitive emissions factor	0.5% of 55.60 $ktCO_2e/PJ$	Derived from gas emissions data from MBIE and the NZ Greenhouse Gas Inventory.[24,38]
Amount of gas travelling through pipeline		Output of the supply model.
Midstream combustion emissions factor	0.21 $ktCO_2e/PJ$	Derived from gas emissions data from MBIE.[24]

Table A15: LNG import related emissions assumptions.

Category	Assumption	Details
Upstream emissions	5.57 $kgCO_2e/GJ$	From a Whole of Life Greenhouse Gas Emissions report.[39]
Liquefaction	4.72 $kgCO_2e/GJ$	From a Whole of Life Greenhouse Gas Emissions report.[39]
Shipping		
Carrying capacity	4.3 PJ	Most common LNG tanker capacity, according to NZ Battey LNG import report.[36]
Distance (port to port)	1898 nm	Assumed LNG is being imported from Australia – from Port Gladstone to Port Taranaki.
Transport emissions factor	16.3 gCO_2/t nm	From an International Maritime Organisation Greenhouse Gas Study.[40]
CO_2e conversion	1.1013	From an International Maritime Organisation Greenhouse Gas Study.[40]
Regassification	1.98 $kgCO_2e/GJ$	From a Greenhouse Gas Emissions from LNG report.[41]

Emissions model

Table A16: LNG import related emissions assumptions.

Category	Assumption	Details
Gas supply		Output from supply model.
End use emission factors		
Industrial stationary combustion factor	54.05 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions.[37]
Commercial stationary combustion factor	54.14 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Residential stationary combustion factor	54.14 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Electricity stationary combustion factor	54.05 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Methanex stationary combustion factor	50.19 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Methanex process emissions factor	2.34 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Ballance stationary combustion factor	44.76 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Ballance stationary combustion factor	5.49 ktCO_2e/PJ	From Ministry for the Environment guidelines on measuring emissions. [37]
Demand fulfilled by hydrogen or biogas		Priority order is residential, then commercial, then industrial, then baseload electricity. Assumed based on MBIE gas price data, where higher historical prices are assumed to indicate a higher willingness to pay a premium for greener gas.

Glossary of terms

Term	Definition
EY	Ernst & Young Strategy and Transactions Limited
CCC	Climate Change Commission
LNG	Liquefied natural gas
MBIE	Ministry of Business, Innovation and Employment
DR	Demand response
CCUS	Carbon capture, utilisation, and storage
2P	The best estimate of reserves – proved plus probable reserves
2C	The best estimate of contingent resources – resources that are not yet economic to recover
PJ (GJ)	Petajoule – 10^{15} joules (Gigajoule – 10^{9} joules)
EDGS	Electricity Demand and Generation Scenarios
TWh	Terawatt-hour (10^{12} watt-hours)
NZ ETS	New Zealand Emissions Trading Scheme
Dry year	A year where low rainfall leads to below average hydro lake levels, and low hydro generation
$MtCO_2e$ ($ktCO_2e$)	Megatonne of carbon dioxide equivalent - 10^{6} tonnes of CO_2e (kilotonne of CO_2e - 10^{3} tonnes of CO_2e)

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