Gas Industry Co.

Briefing to Incoming Minister of Energy

November 2023

This briefing sets out the role of Gas Industry Co as co-regulator, key issues affecting the industry for your attention, and our work programme priorities.

In this briefing

- Key issues for your attention
- About Gas Industry Co and New Zealand's gas sector
- Our work programme priorities
- Quick facts about natural gas.

Key Issues for Your Attention

- Natural gas production will be insufficient to meet demand between 2025 and 2027.
- Investment is needed to avoid gas and electricity shortages. Low investment confidence is affecting field development.
- The government may need to negotiate with pivotal players in the market to ensure sufficient investment occurs for energy security during the transition. Priorities are to negotiate ahead of time to have gas available for electricity in dry years, and to build new gas peaking plant.
- We do not currently expect to see investment in new gas peaking electricity generation, nor in field development to support it. Electrification currently requires continued flexible gas supply. New market arrangements will be needed if the required plant investment is to occur.
- Carbon capture and sequestration is feasible in New Zealand today and can help to reduce carbon emissions while ensuring secure gas availability. Modernised regulatory settings are recommended.
- Biogas is a long-term solution for decarbonising residential and small commercial gas, which are a minor part of the gas market. A ban on gas connections is inconsistent with the development of a biogas market.
- Industrial gas use will likely decline in response to carbon price. De-industrialisation is a risk as some industrial gas consumers do not have a realistic alternative fuel and will exit New Zealand if gas is not available.
- The carbon price is driving innovation and transition efficiently. Further interventions may inhibit investment in the transition and cause avoidable de-industrialisation without achieving emissions reductions at an efficient cost of abatement.

Gas Supply and Demand

Commercially viable future natural gas production is estimated to be insufficient to meet demand at some stage between 2025 and 2027. Even if production from '2C' resources, which is not currently commercially viable, comes online gas production will be insufficient to meet demand at some stage between 2028 and 2034. Investment can bring new gas supply to market but uncertainty is affecting investment.

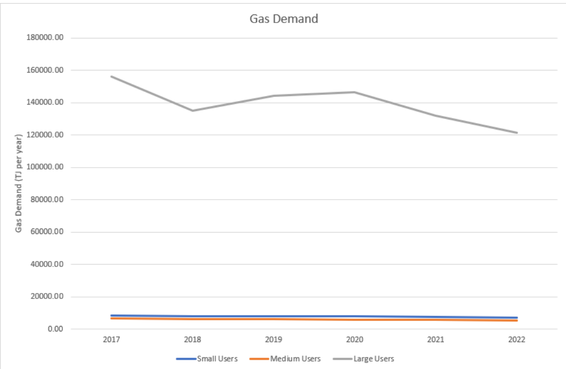
A supply and demand study for Gas Industry Co is due to be published by the end of November 2023. A copy is attached to this Briefing. It shows that demand for natural gas is decreasing. Much of the decrease in gas consumption is due to supply constraints. For example, Methanex's Waitara methanol plant is closed because insufficient gas is available.

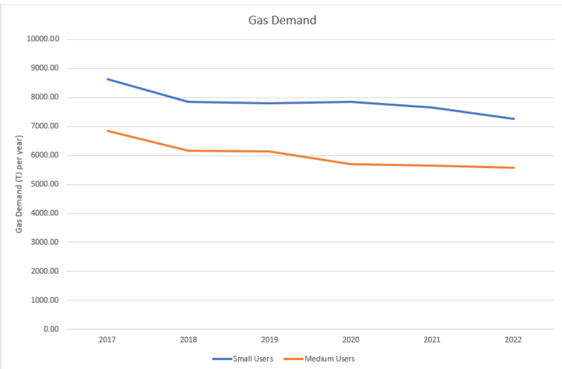
Gas in New Zealand is produced in response to long term purchase contracts. Spot market demand is not sufficient in New Zealand to develop gas fields. There is no existing alternative buyer of sufficient scale, other than petrochemicals (Methanex and Ballance Agri-Nutrients), to underwrite field development. If demand from large users disappears, remaining demand is unlikely to be sufficient to underwrite development.

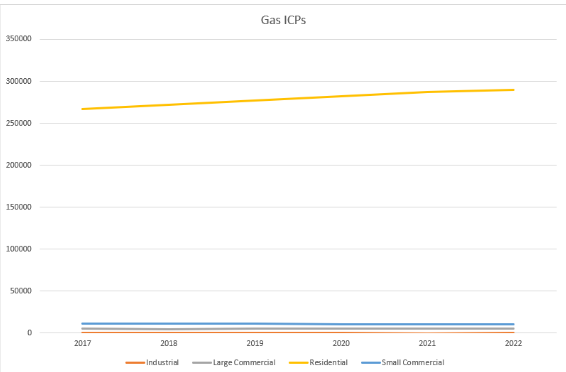
Gas Industry Co estimates $200-300 million a year of investment in field development is needed to replace produced volumes. The environment for investment in new natural gas supply is challenging and will likely require supportive stances from both Government and industry.

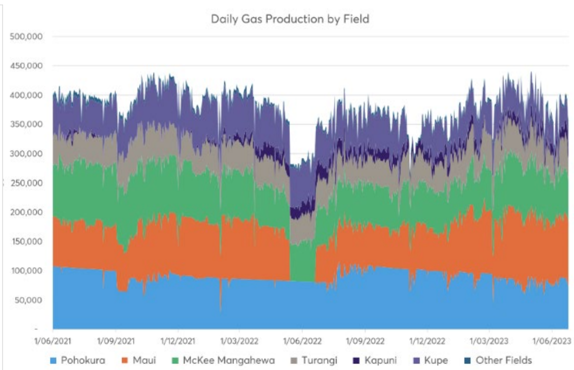
All New Zealand's remaining gas fields are in decline. As fields deplete, New Zealand will be dependent on fewer fields, which increases the risk that forecast resources will not be delivered.

In our June quarterly report, we stated that, in the financial year ending 30 June, less gas was supplied than in any year since the mid-1980s.









Gas Transition Plan

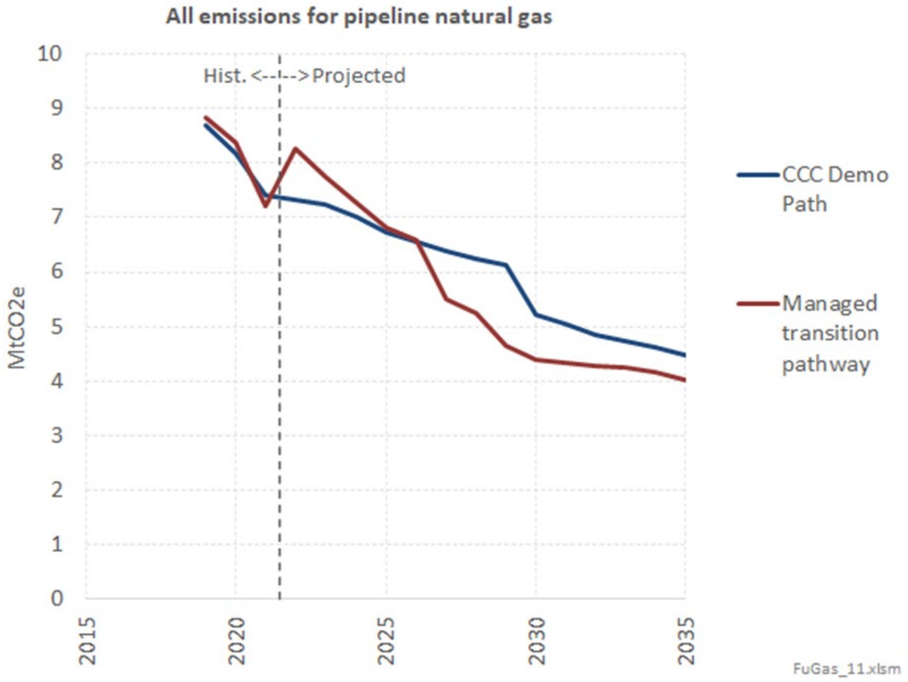
Gas Industry Co has been working in conjunction with MBIE on a Gas Transition Plan. The purpose of the plan is to provide sufficient clarity about policy direction for investors to be confident to develop fields and plant while the energy system transitions to Net Zero carbon emissions.

In 2021, Gas Industry Co looked into whether gas market settings are fit to support security of supply[1]. We found investors lack confidence that they can make a commercial return, presenting a risk that the required level of investment will not be made, which could lead to a potential disorderly transition. We recommended a Gas Transition Plan. Following publication of our investigation, the emissions budgets to 2035 were announced, setting out sector initiatives to achieve them. The government at the time did not action Climate Change Commission advice to ban new gas connections. It asked Gas Industry Co and MBIE to work in conjunction to develop a gas transition pathway.

Gas Industry Co drafted a transition pathway in January 2023 based on insights from specialist experts, targeted engagement with industry, and our own assessment. MBIE released a discussion document in August 2023. It was informed by the draft plan prepared by Gas Industry Co and supporting research documents.

The work to date establishes that a transition can be achieved that provides secure, sustainable, and affordable energy.

The chart below shows emissions from pipeline natural gas in the pathway recommended by Gas Industry Co compared to the Climate Change Commission's demonstration pathway.



In Gas Industry Co's recommended pathway:

- Significant emissions reductions occur in the 2020s as electricity generation moves from gas to renewables in response to carbon prices.
- New gas peaking generation after 2028 is provided for, to ensure security of electricity.

[1] Gas Market Settings Investigation

- An economic instrument is needed to make gas peaking generation commercially viable.
- Carbon emissions sequestration (CCS/CCUS) can substantially decarbonise gas production and provides an option to decarbonise some 'hard to abate' industrial sectors. CCS is ready to commence as soon as 2027. The existing regulatory framework for managing CCS should be modernised.
- Industrial demand for natural gas is estimated to reduce in response to carbon prices consistent with emissions budgets. No further intervention, such as bans, subsidies or changes to consenting rules, are required to decarbonise industrial use of gas. Further interventions may risk investment in transition not occurring.
- All of New Zealand's gas fields are in their decline phase. Continued investment is required to maintain deliverability from those fields (such as compression projects to maintain well pressure and new wells to access discovered but undeveloped resources). With investment in field development, supply is expected to be sufficient to meet demand out to the 2040s.
- The volume of gas available in future depends on investment. It is not a 'fixed' total volume to be allocated. If large industrial demand exits, especially methanol production, then *less* gas is likely to be available to other users (that is, the exit of petrochemical demand would not 'free up' gas for other users – it would reduce production volumes).
- As not all industrials have a viable alternative energy source, some industrials will relocate to lower-cost jurisdictions as carbon prices rise and potentially because of uncertainty over gas availability. New Zealand's emissions would reduce with no impact, or negative impacts, for global emissions.
- Residential and small commercial use of natural gas is a minor proportion of overall gas consumption. Sufficient biogas exists today at feasible prices to decarbonise 20% of residential demand, but a biogas market needs to develop. More biogas may become economic in volumes consistent with reaching net zero. If new gas connections are banned, a biogas market is unlikely to develop.
- Local distribution networks may be able to transition to biogas and can be economically operated at much lower gas volumes than today. Gas Industry Co commissioned a review of regulatory models for pipeline infrastructure and sees no need to update regulation of networks yet, but this will need to be revisited in around ten years.

Gas Industry Co's updated draft transition plan sets out how this transition can meet your objectives. A copy is appended to this Briefing and summarised in the graphic below.

Gas and electricity markets

Electricity market arrangements will be needed to incentivise gas storage, demand response, and investment in peak generation.

Current arrangements will need to be updated if the system becomes more dependent on intermittent gas generation.

While thermal generators procure gas supply for their own customers' needs, the *wider electricity system relies on thermal support* for periods when insufficient renewable generation is available.

> **No mechanism currently exists to incentivise sufficient thermal supply to be available when the electricity needs more thermal energy than is currently contracted by electricity companies for their own customer sales.**
>
> **This is a significant, unmanaged, system risk.**

The example of winter 2021 provides a preview of the consequences: In an energy shortage, extra gas was secured by Genesis from Methanex, which supported the electricity sector at considerable cost to those two entities. To surrender that much gas, Methanex had to shutter production (it brought forward a planned maintenance shutdown and its Waitara plant closed. Waitara has not since re-opened). Genesis had to pay a high price for the gas surrendered, which meant higher electricity demand flowed through to high contract prices for other gas consumers.

Electricity generators that were not party to the contract between Methanex and Genesis may benefit from higher system prices without contributing to the cost of energy security.

The 2021 conditions are likely to be repeated at some point during the 2020s. If arrangements are not made *in advance of being needed*, then seasonal demand response will be expensive and difficult to negotiate (like buying insurance after an insurable event has already occurred). Moral pressure to make arrangements under conditions of system stress is probably not economically efficient and presents a sovereign risk to inward investment.

Although the electricity and gas markets have an interface, they operate in different ways.

- The electricity system is designed around the ability of generation and transmission to meet peak residential load. Unlike electricity, gas meets peak residential load from flexible pressure in the gas pipeline system. Its flex helps to smooth intraday peaks, which substantially reduces the cost of the system.

- Electricity brings more capacity to market in response to higher prices, but gas works on fixed long term contracts. While pipelines provide short-term flex, field production volumes cannot easily be varied regardless of the propensity of electricity to pay. However, gas *could* meet this variable role.

  More gas could be made available for dry year security if the market paid for gas to be available from flexible storage or purchased options contracts to divert gas from other purposes (demand response). In most cases, demand response is likely to be more economically efficient.

Gas can provide intermittent generation to support renewables, but dry year resilience requires economic arrangements to be put in place in advance so that gas is kept in storage or demand response options make gas available when needed.

We expect to discuss options for policy interventions with you soon and learn your appetite for the balance of relevant risks.

An opportunity could be taken to explore a negotiated agreement with a large gas user comprising an option for demand response, and undertakings about investment (including investment in efficiencies and decarbonising technology). Any counter-party would likely seek undertakings on industrial allocations and security of petroleum mining.

Renewable gases

Opportunities are available today to decarbonise more of the gas sector through biomethane. Subsidies are not required and the market should choose the highest value use of biogases.

Biogas

As part of our work on the Gas Transition Plan, we commissioned engineering consultants WoodBeca Ltd to complete research on the supply potential of biogas and renewable LPG production.

WoodBeca inventoried the entire New Zealand biogas feedstock. The graph below sets out the volumes of biogas that could become available at various price points. WoodBeca estimated that up to 3PJ could be available at less than $20/GJ[2].

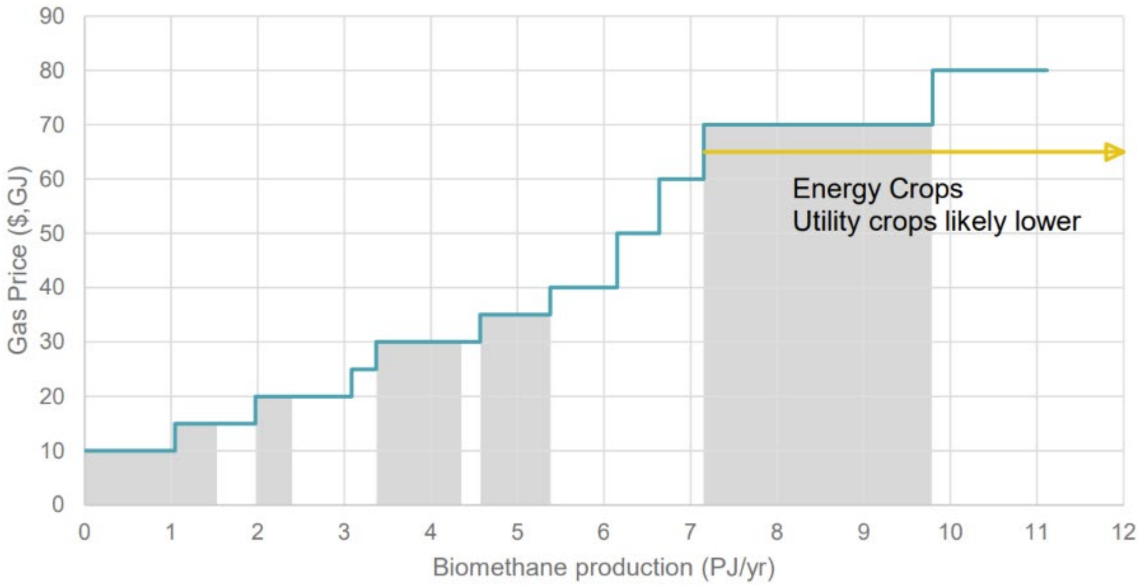
The total sum of biogas that could be produced today is around 7PJ, but the marginal cost of much of this gas would likely exceed the willingness to pay even with a high carbon price.

[2] For comparison, the current natural gas price ranges from $6-9/GJ. The cost of gas makes up around 15% of an average household gas bill – and a much larger proportion of larger users' gas bills. Tax and ETS costs, transmission, marketing and admin costs, make up most of the rest of the bill. 3PJ represents about half of residential natural gas consumption today or 2% of natural gas produced last year.

As the cost of gas is a smaller part of the final bill for residential consumers than for industrial gas users, residential consumers have a higher propensity to pay for biogas. Residential consumers in total use about 6PJ of gas each year, a small percentage of total gas (4%).

If half of feasible biogas (1.5PJ) were to be available for residential consumers, then up to a quarter of residential gas demand could be decarbonised in the 2020s at feasible prices. Mechanisms are available to certify and trade biogas in the existing system, which would ensure gas was allocated to its highest value use.

The chart below depicts the volumes of biogas that could be available at various prices.



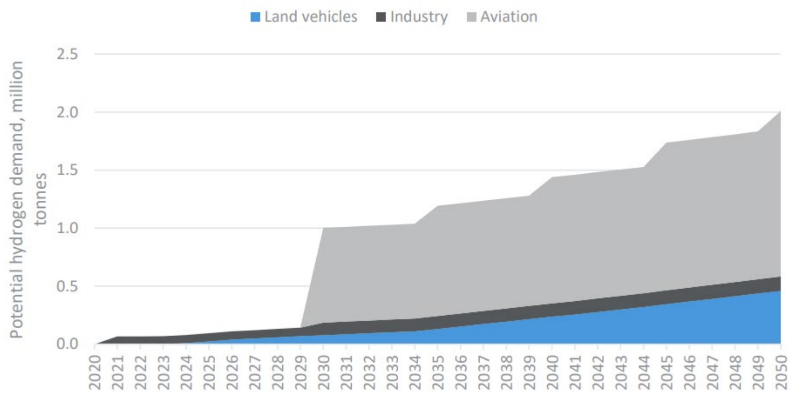
Note: grey columns indicated the quantities based on the case studies

The average lifecycle emissions of biogas generated from organic wastes and residues are a 70% reduction compared to natural gas or LPG. When biogas is derived from material going to landfill, or from processes that generate large quantities of biogenic methane (e.g. waste water), capturing and upgrading the gas for use represents a large net reduction in overall GHG emissions intensity.

Hydrogen

Gas Industry Co commissioned consultants Castalia to provide expert economic analysis and modelling of likely hydrogen scenarios. It found that, while hydrogen could play an important role in decarbonising hard-to-abate sectors such as heavy transport and aviation, hydrogen is unlikely to be deployed at scale in existing natural gas infrastructure. As shown in Figure 0.1 below, New Zealand could demand a large amount of green hydrogen, but the demand is likely to be located in a way that does not require production in Taranaki nor transmission across large distances.

Figure 0.1: Most optimistic demand for hydrogen in New Zealand



Note: Land vehicles include heavy industrial vehicles, heavy trucks, heavy buses, and light vehicles. Industry includes fertiliser and steel production.

Blue hydrogen (made from natural gas with CCS to remove carbon emissions) would also help decarbonise natural gas, in which case New Zealand would probably continue to consume natural gas, rather than using natural gas to produce hydrogen for the same use cases.

Blended hydrogen could be financially viable for commercial and residential consumers on the distribution network. This might make hydrogen blending a viable option for partial decarbonisation if there is a technological breakthrough that lowers the cost of hydrogen or enables higher blending rates. However, blended hydrogen has a high marginal abatement cost, and is unlikely to be cost effective at reducing emissions compared to other options.

> Gas Industry Co recommends that you support initiatives that remove barriers to hydrogen, but policy should not rely on hydrogen replacing natural gas as a decarbonisation strategy.

Carbon Capture, Utilization and Storage (CCS and CCUS).

- Emissions capture is technically and economically viable and is ready to begin in the mid-2020s.
- Emissions capture technology is mature, safe, and stores carbon better than alternatives such as forests.
- Significant emissions reductions can be achieved.
- Without CCS, the gas sector's target emissions reductions cannot be achieved consistently with objectives for security of supply and affordability.
- Reform is desirable to allow captured emissions to avoid the carbon cost, to consenting regulations, and to improve governance of sites post-operation.

As part of its work for the Gas Transition Plan, Gas Industry Co commissioned complementary reports:

- WoodBeca looked at the technical and economic viability of CCS in New Zealand.

WoodBeca confirmed emissions capture projects are technically viable at OMV's offshore Taranaki Maui East field and at Todd's onshore South Taranaki Kapuni field.

These two projects are examples. Other potential projects exist that may further reduce emissions. Both projects could commence CCS operations in 2027.

- Professor Barry Barton of Waikato University law school looked at the regulatory issues.

Legal issues that need to be resolved are set out in the table below:

Issue	Cause	Management option
Compensation	Contribution to the public for the use of a common resource for disposal	A form of royalty is payable to the Crown for extraction of resources. A similar arrangement for disposal is likely to be expected, but the economics of disposal are less amenable than the economics of extraction. Some proportion of the value of disposal may be paid as a royalty to the Crown on behalf of the public, and potentially to the landowner and mana whenua in recognition of their interest.
Operational risk	Potential for seepage or release of CO_2 from the reservoir	As for oil and gas extraction, sites and operations will be approved only if they are assessed to be secure and stable. If CO_2 were released, the safety of the site would be subject to well site safety regulation. A release would contribute to overall global emissions, but otherwise CO_2 is a component of air, harmless, and contained in everyday products including food and drink.
Monitoring during operations	Emissions capture is envisaged to continue for one to two decades.	Liability during operation for the cost of monitoring would lie with the operator, with existing monitoring and assurance arrangements as for existing subsurface operations. A liability bond market (a kind of insurance) is vibrant in the US and Canada, and provides for the costs of remediation in the event of operator default.
End of operations	Well abandonment and approval of post-operation arrangements.	Regulatory arrangements and approvals for permanent underground disposal.
Post-operation monitoring	Ensuring the reservoir is stable and CO_2 is not being released back to the atmosphere.	Sub-surface monitoring is well understood. It is likely to be conducted using equipment in the well site and potentially acoustic sampling (depending on the type of reservoir). Liability for the costs of monitoring would rest with the operator until such time as the regulator was satisfied. In some jurisdictions this can last for 50 years, although the expectation is that a regulator can certify compliance in 5-10 years. Some form of bond or insurance is needed to cover events where the operator can't.
Repair and well interventions	As for monitoring, liability for the cost of repairs needs to be assigned.	Liability for post-operation repairs should rest with the operator until the regulator certifies that the reservoir is likely to be permanently stable. As for monitoring, some form of insurance or bond is required to provide for circumstances where the operator is no longer available.
Ongoing ETS liability	Emissions will only be sequestered when someone can avoid a carbon charge. If the carbon is later released, then the carbon cost is avoided unfairly	Liability for avoided carbon costs can be treated the same way as liability for monitoring and repairing sites.

Transfer of risk	At some point the operator's liability ends.	Companies eventually cease operations and need to be able to move on from projects. Operators should not generally be able to avoid costs of their operations, but at the point where further costs are unlikely to be incurred, risk is generally likely to be transferred to the Crown. The liability is similar to the end of mining operations. The Crown may collect a royalty during operations in recognition of its ultimate residual liability.

CCS and the ETS

- **CCS is made economic by allowing operators to avoid the carbon price. Reform is required to allow access to the economic opportunity.**

No ETS carbon credit ('NZU') needs to be surrendered under existing rules if carbon capture technology occurs 'behind the gas meter', which means no change to the ETS is required to facilitate CCS at a production well where carbon dioxide is stripped from gas as it is produced then reinjected into the well. However, one advantage of CCS is potential transfer into a suitable site, e.g. at an industrial hub. Producing from one well, then removing CO_2 and sequestering it in another operator's well, currently requires surrender of a carbon credit, which removes the economic benefit of CCS. A site operator needs to be able to capture the economic benefit of capturing and sequestering emissions by avoiding the cost incurred when carbon is emitted).

CCS and electricity

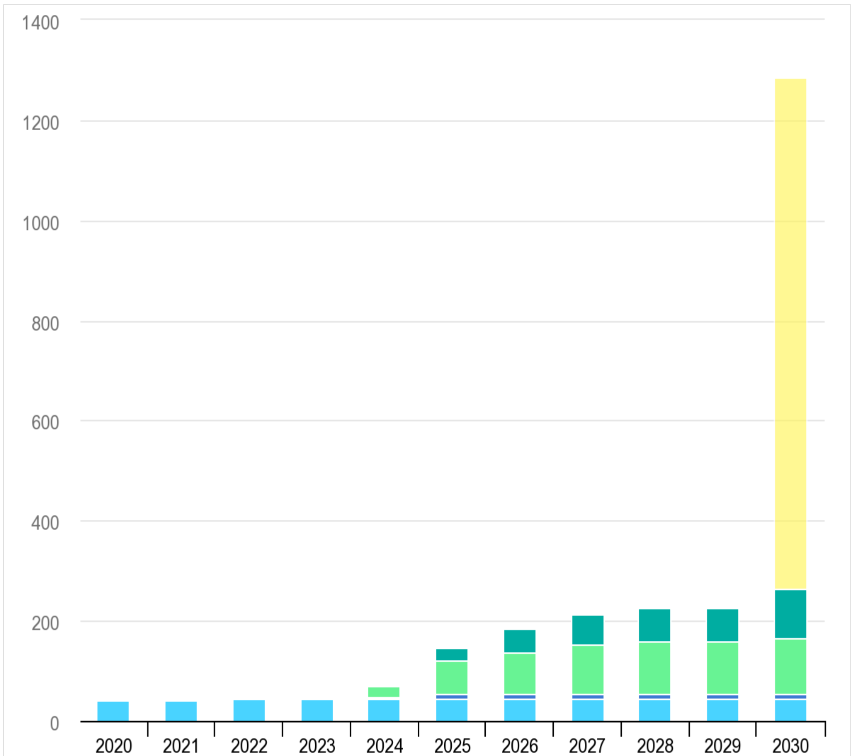
- CCS can be used to remove almost all emissions from electricity generation. However, CCS is generally less economic for decarbonising electricity generation than paying the expected carbon price.

Requiring a new gas peaking plant to use CCS would cost more than paying the carbon price. It may be viable to require any new gas peaking plant to use CCS because of the high propensity to pay when gas peakers are required to run.

"Reaching net zero will be virtually impossible without CCUS"

- International Energy Agency, Special Report on Carbon Capture Utilisation and Storage, 2020.

Global CCS projects: Current, Planned, Required in Net Zero



About Gas Industry Co

Gas Industry Co is the industry-owned co-regulator

Gas sector co-regulation is a hybrid of self-regulation and ministerial approval. Gas Industry Co is the industry body approved by you as minister[3] to work with industry on gas governance, facilitating markets, and providing trusted advice.

Gas Industry Co is owned by 12 industry shareholders and governed by a board of directors appointed by shareholders. Our board comprises four independent directors: Rt Hon Jim Bolger ONZ, Andrew Brown, Sam Elder, and Sir Brian Roche, and three industry directors: Babu Bahirathan (Nova Energy CEO), Mike Fuge (Contact Energy CEO) and Paul Goodeve (Clarus CEO).

Our work program is approved through a consultation process with the industry and government. We report to you quarterly and annually. You are annually asked to approve the work programme set out in our Statement of Intent following consultation with industry, and our recommendation for the annual industry levy to fund our operations.

A government policy statement approved in 2008 directs us to work towards safe, efficient, reliable, fair, and environmentally sustainable gas delivery. Generally, we look for non-regulatory options. When regulation is needed, we make recommendations to you for regulatory governance arrangements. For certain regulatory recommendations specified in the Gas Act, your approval can generally only be withheld for failure to follow process.

The co-regulatory model has proved highly successful for regulating the sector.

The model has proved adaptable to the demands of the energy transition. The industry bears most of the costs of regulation, regulation is highly responsive, and costs are very low compared to alternative models.

This year our levy reduced, after an increase last year to accommodate our expanded work programme[4].

Our funding

Gas Industry Co receives no government funding. It is entirely industry funded to meet the expected costs of delivering effective co-regulation and fulfilling its statutory and GPS obligations:

Levy funding

Under Section 43ZZB of the Gas Act we make recommendations to you for the levy that industry participants pay to cover the costs of our policy work and market administration.

Market fees

Funding by industry participants pays for activities such as Switching Rules, Reconciliation Rules, Critical Contingency Regulations, and Compliance Regulations.

Annual fees

The Board sets an annual fee, currently $2,000 per shareholder per annum. These fees are set aside to establish cash reserves.

Most of our levies are set on the basis of volumes of gas produced or the number of customers collected.

[3] under Part 4A of the Gas Act 1992

[4] mainly associated with the Gas Market Settings Investigation and Gas Transition Plan.

As the volume of gas consumed declines, the levy basis may need to change. We expect to review funding in a future work programme.

Our work programme priorities

We set our work programme priorities for FY2024 at our annual co-regulatory forum in December 2022. Consultation on the following year's (FY2025) work programme will commence in December this year, when industry participants and government officials come together to discuss our work priorities for the financial years ahead.

Our work programme is grouped into gas governance, facilitating industry systems and processes, and trusted advisor to government and industry. This coming FY2024, our work programme focuses on our gas governance role through a number of recently commenced or proposed changes to gas governance arrangements.

Role	Comprising
1. Gas governance	• Critical Contingency Management • Guidelines to Enhance Consumer Outcomes • Advanced Gas Metering • Retail Gas Contracts Oversight Scheme • Gas Distribution Contracts Oversight Scheme • Downstream Reconciliation and D+1 • Switching and Registry • Compliance and Enforcement • Statement of Intent and Annual Report • Other Reporting
2. Facilitating industry systems and processes	• Information Disclosure • Gas Transmission Pipeline Access
3. Trusted advisor to government and industry	• Gas Transition Plan • Energy Transition

Examples of gas governance

Critical Contingency Management

We are progressing amendments to regulation of the industry's response during supply emergencies. These changes have been driven by experience with the regulations and feedback on events and exercises. We expect to make a recommendation to you and support MBIE through the legislative change process.

Retail Gas Contracts Oversight Scheme

We monitor industry alignment with Gas Industry Co's guidelines to enhance consumer outcomes. An independent assessment was carried out early this year of retailer contract terms for small consumers. The independent assessor's benchmark assessment report found all 11 sets of retailer terms and conditions were substantially aligned with the benchmarks. The benchmarks with the highest concentration of non-alignment are *clear price increases*, *clear disconnection processes*, and *clear description of liability and redress*.

Switching and Registry

The purpose of the Switching Rules is to establish a set of gas switching and registry arrangements that will enable consumers to choose, and alternate, efficiently and satisfactorily between competing retailers. The Switching Rules provide for a centralised database, the gas registry, which stores key technical parameters about every customer installation and facilitate and monitors each customer switch from initiation through to completion. Our work includes managing the registry operator contract, assessing the ongoing performance of the switching rules, performance and event audits.

Trusted advisor to government and industry

Energy Transition

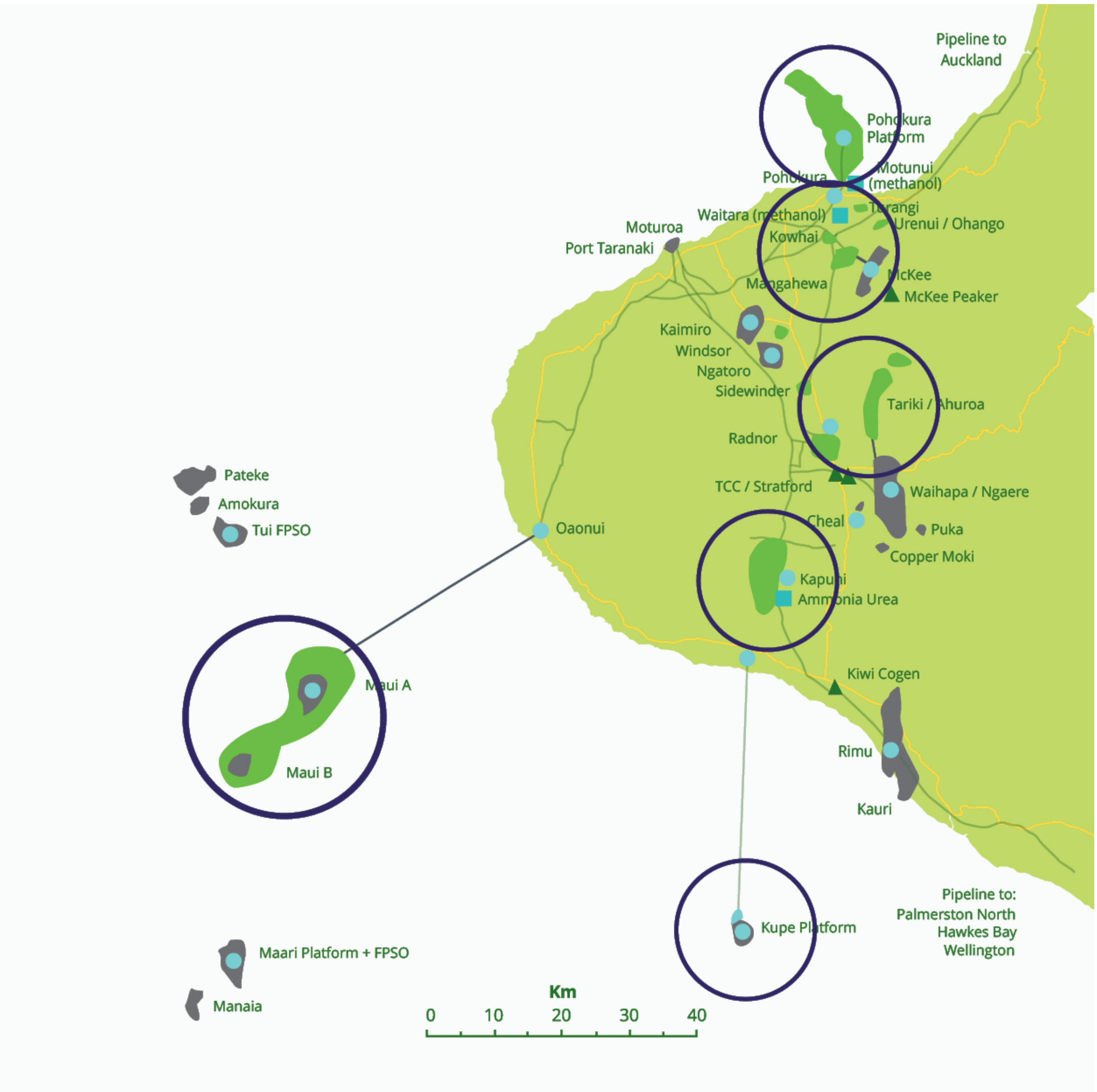
Measures to ensure gas is available through the transition include:

- The Gas Transition Plan is a major focus of our trusted advisor work.
- Our regular supply and demand study.
- Consideration of mechanisms to ensure natural gas is available in times of unexpectedly tight supply.
- The role of new gases, such as hydrogen and biogas; and
- Engagement with agencies responsible for achieving emissions reductions to align with security of supply and emissions reductions plans in the gas sector.

Quick essential facts about gas

Main producing fields

- There are six main natural gas fields in New Zealand.
- Three are offshore: Pokohura, Maui and Kupe.
- Three are onshore fields: Mangahewa, Turangi and Kapuni.
- Another twelve minor onshore fields also produce gas.
- All gas produced in New Zealand comes from Taranaki.
- Gas is also held in storage at Ahuroa. It can store up to about 10PJ of gas.



Who uses gas

- 300 large industrial gas customers.
- 5000 large commercial gas customers.
- 11,000 small commercial consumers.
- 290,000 residential customers, who comprise less than 5% of natural gas consumption.

About a third of gas is used to generate or co-generate electricity. Gas will largely exit electricity generation by about 2030, except for peaking generation.

The largest gas consumer, and New Zealand's largest energy buyer, is Methanex. 95% of the methanol it produces is exported to Asia Pacific, where it is either used in products such as plastics and chemicals or combusted in industrial processes. It earns $835 million for New Zealand. The energy value of Methanex's gas consumption is roughly equivalent to the entire hydroelectric sector. Green methanol is technically feasible but not economic under current settings.

Ballance fertiliser, used on many Kiwi farms, is usually made from New Zealand gas. Ballance competes against imported product, which is generally manufactured more cheaply but is more expensive to land in NZ because of transport costs. Ballance may have opportunities to reduce gas used in production processes, but the fertiliser product embeds carbon. Reduced fertiliser usage would reduce the economic productivity of land, so therefore a pathway to decarbonise is unclear.

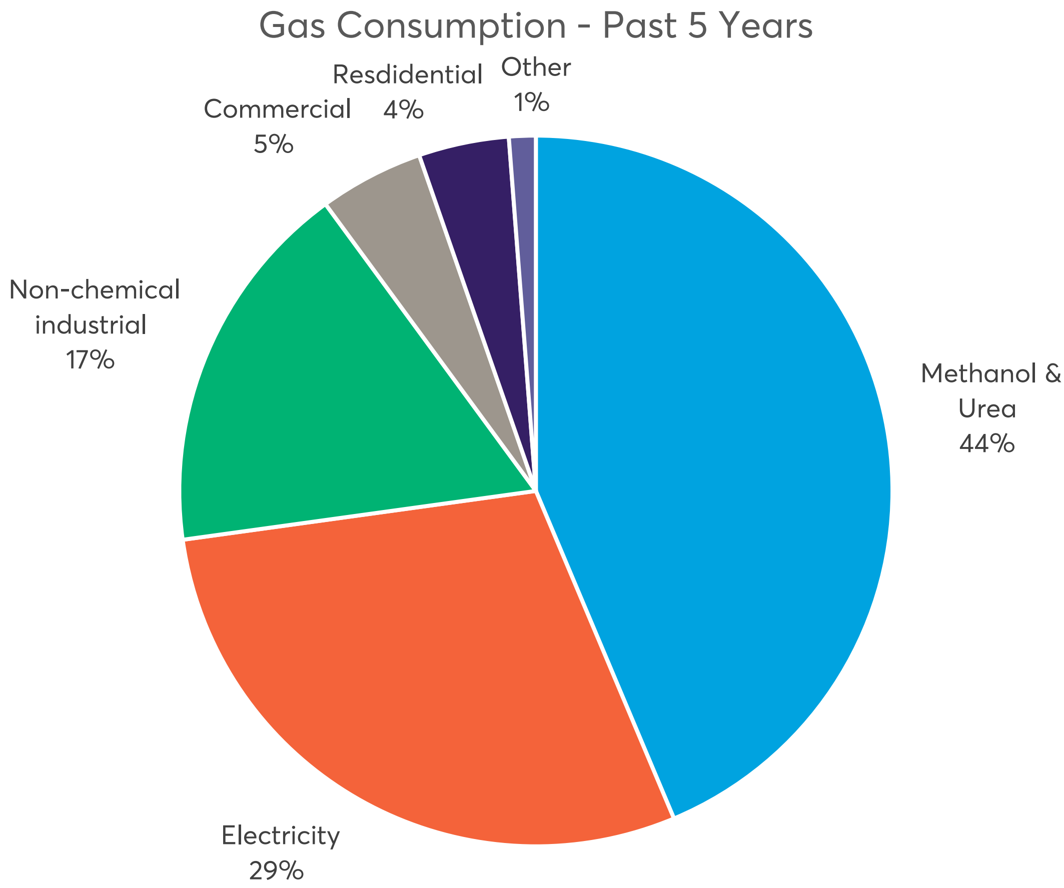
After electricity and petrochemicals, gas is mainly consumed by large industrial and commercial gas customers around the country. 300 large industrial gas customers include steel manufacture at Glenbrook, wood processors use gas to achieve high temperatures and dairy plants use gas for process heat.

5000 large commercial gas customers use gas in activities such as space heating and hot water for hotels, often in remote locations or buildings where the footprint of electric hot water is unsuitable. Natural gas is used to help ripen vegetables in greenhouses.

11,000 small commercial businesses. Precise temperature control is often needed in high value export products, such as chocolate or Central Otago pinot. Most restaurants use gas to cook.

About 4-5% of gas is used by residential customers.

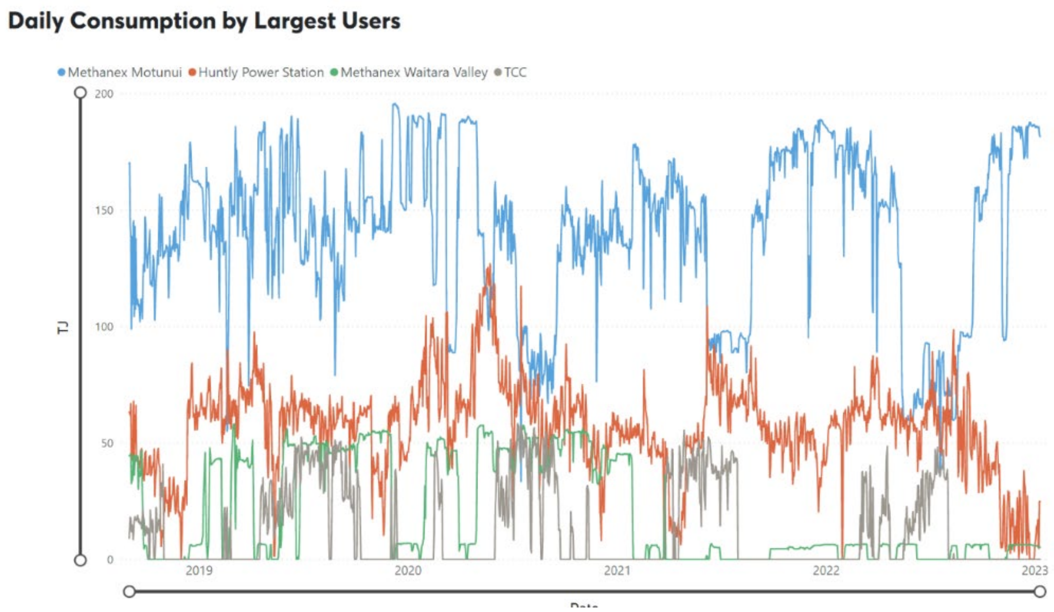
95% of traded gas is sold under long term contracts, so gas prices do not immediately rise in response to conditions internationally. However, when lake levels are low, electricity has the highest propensity to pay for gas and will bid prices up for the remaining 4-5% of uncontracted volumes to achieve a demand response. This was seen in 2020, when lake inflows were low while production from Pohokura, the largest gas field, was reduced. Some industrial and commercial customers were in the market to renew contracts at that time and found renewal prices were high because of price competition from electricity. Competition for energy also resulted in some customers being unable to obtain gas at all, which resulted in some industrial exit and reduced industrial production shifts.



New Zealand produced around 200PJ of gas through most of the 2010s. This fell to about 150 PJ last year.

Role of Methanex

Methanex is New Zealand's largest energy user. Methanol and large industrial customers are major gas users, as can be seen in the graph below:



Methanex is crucial to the security of supply of gas (and therefore electricity and other large crucial industries) because of its dominant role in gas consumption. Demand from Methanex underwrites most field development since producers do not invest in new production without sales contracts.

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NEW ZEALAND / TARANAKI

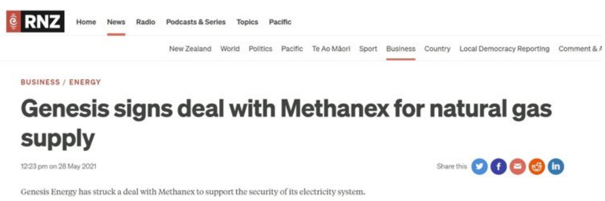
75 jobs to go as Taranaki methanol producer Methanex plans to close plant

One of Taranaki's big industrial players, Methanex, has confirmed 75 jobs will be lost after its decision to close one of its plants, citing an inability to secure gas supply as the reason for shutting it down.

ENERGY

Gas market crisis averted as Methanex cuts production

Pattrick Smellie
Fri, 28 May 2021



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BUSINESS / ENERGY

Genesis signs deal with Methanex for natural gas supply

12:23 pm on 28 May 2021

Share this

Genesis Energy has struck a deal with Methanex to support the security of its electricity system.

How much gas is left?

Our November 2023 supply and demand study is attached, and sets out projections for gas availability in various potential scenarios.

'Reserves' describe the category where gas has been discovered and a decision has been made to develop the gas field. '2P' reserves are mid-range estimates of volumes, where there is a 50% chance the volume ultimately produced could be greater or lower.

Other known gas volumes that have been discovered are called '2C resources.' These are 'contingent' volumes, meaning that production is contingent on something changing such as the economics of production or reassessment of field properties. Rules prohibit field owners from describing 2C resources as 'reserves' because at the time they are assessed, and even though they are known volumes of hydrocarbon, no decision has been made to produce them.

Gas Industry Co estimates that around $200 million of investment is needed each year to continue development of reserves and resources. The volume of remaining reserves varies not just with consumption and discovery, but also with investment decisions by field operators.

In 2023, MBIE substantially reduced its assessment of gas reserves. Some of this reduction was the result of an engineering assessment of well performance. A larger cause was a reduced likelihood that fields would be ultimately developed.

Gas Industry Co investigated the issues around security of supply in our Gas Market Settings Investigation in September 2021.

The main issues uncovered in the investigation were;

- Risks to investment in gas needed for security of supply to electricity and industry;
- Commercial arrangements for electricity dry-year security; and
- Uncertainty about the gas transition to the low carbon economy.

The Gas Transition Plan is addressing some of the issues around security of supply.

Further work is needed to resolve commercial arrangements for gas supply to provide electricity dry-year security.

For more information

Our website www.gasindustry.co.nz has more information about Gas Industry Co, specific work programmes and their history, the structure of the gas industry, and helpful data resources about the use of gas in New Zealand.