The Role of Gas in Electricity and Industry

Prepared for Energy Resources Aotearoa

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Box 478, Level 4, Consultancy House, · 7 Bond Street, · DUNEDIN · Phone +64 3 479 2475

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Definitions

The following abbreviations and acronyms may appear in this report.

2C	Contingent gas reserves with a 50% likelihood of being exceeded
ACOT	Avoided cost of transmission
AGS	Ahuroa Gas Storage facility in Taranaki
CCC	Climate Change Commission
CCGT	Combined-cycle gas turbine
CO_2-e	"CO_2 equivalent" a term used to refer to greenhouse gases, one tonne of which has the same radiant forcing (warming) impact as one tonne of atmospheric CO_2
EAF	Electricity Allocation Factor
ENZ	The *Energy in New Zealand* report published annually by the MED (replaces the *Energy Data File*)
EMarket	The model developed and used by Energy Link to perform the electricity market scenario modelling underlying Price Path and custom forecasts..
ETS	The New Zealand Emissions Trading Scheme
EU	European Union
EUA	EU Emission Allowance (issued under the European Union Emission Trading Scheme)
EV	Electric vehicle
FPO	Fixed price option for the ETS
GHG	Greenhouse gas
GMarket	The model developed and used by Energy Link to perform the scenario modelling for gas prices in Energy Link's Price Paths and forecasts.
GXP	Grid Exit Point
Huntly e3p	CCGT power station at Huntly
Huntly p40	48 MW OCGT power station located at Huntly
HVDC	High voltage direct current
ICP	Installation Control Point
I-Gen	Energy Link's model for determining when new generation plant is likely to be built
IPP	Independent power producer
LCOE	Levelised cost of energy
LRMC	Long-run marginal cost
MBIE	Ministry of Business Innovation and Employment
MDAG	Market Development Advisory Group
NZU	New Zealand Unit, the permit to emit one tonne of CO_2-e
OCGT	Open cycle gas turbine
OTB	Outside the Box – refers to a scenario we highlight each quarter. The OTB scenarios are not weighted into the Energy Link Price Path.
P50, 2P, P2	Proven and probable gas reserves with a 50% likelihood of being exceeded
PFC	Energy Link's Monthly Price Forecast for the coming 12 months
PPA	Power purchase agreement
PHES	Pumped-hydro energy storage
PPI	Producer Price Index
POCP	Planned Outage Co-Ordination Process
PV	Photovoltaic
ROI	Return on investment
SRMC	Short run marginal cost
TCC	Contact Energy's 365 MW CCGT plant in Taranaki
TPM	Transmission Pricing Methodology
TWAP	Time-weighted average price
WACC	Weighted average cost of capital

Disclaimer

In preparing this report, Energy Link has made predictions of the outcome of future events including, but not limited to, spot electricity prices, electricity forward and futures market prices, local and national demand for electricity, hydrological inflows to river systems, temperature and weather conditions, the nature of and prices in carbon and gas markets, and the bidding and purchasing behaviour of participants in electricity and other markets. Energy Link has made such predictions in good faith and Energy Link will not be held liable for the actual outcomes of the specified events, for the accuracy of its predictions or for any special or consequential damages or losses resulting in any way whatsoever from the purchase, consideration or use of Energy Link's forecasts.

Although the type of data provided in this report may be regarded as an essential input into the process of optimising hedging and other commercial strategies, unless otherwise agreed, this report in itself does not in any way constitute advice about hedging or other commercial strategies. Advice about hedging or other commercial strategies should take account of a number of other important factors and should be sought separately from Energy Link, if required.

How to Interpret our Forecast Prices

The headline forecasts that appear in this report (including in various charts) are typically (unless otherwise stated) either an average or median value taken from the large range of scenarios that we model. As such, none of the headline forecasts represent an actual single scenario. Weighted average forecasts are expressed as "expected prices" in the sense that if the forecast period is repeated hundreds of times then the prices should average out to the expected values. It is therefore coincidence if prices turn out to be the headline values.

So, what are the expected prices useful for? They are a benchmark for hedge prices, since in theory hedges should represent expected future spot prices, which is why it is also relevant to plot them next to ASX prices, for example. They are also a guide to where spot prices might go on average. For planning and budgetary purposes, it is important to realise that prices could turn out substantially higher or lower, depending on what happens over the coming years. Percentile and other charts and tables in this report are intended to provide you with guidance as to the range of spot price outcomes, and to the assumptions underlying the spot price modelling.

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1 Introduction

Energy Resources Aotearoa (Energy Resources) engaged Energy Link to provide independent analysis of the range of natural gas consumption for electricity generation expected over the long-term. The analysis is primarily based on generation data extracted from Energy Link's standard long-term Price Path, along with historical data from the last five years. The Price Path is independently produced by Energy Link using publicly available information, our electricity-related models, and our expertise, built up over decades of on-going research into the energy markets in Aotearoa New Zealand.

Energy Resources wishes to understand how much gas is required to support the electricity market over the longer term, including how this would change if the Rankine units at the Huntly power station (owned by Genesis Energy) were to run only on gas.

The Huntly power station consists of six units:

- the four 250 MW Rankine units are steam turbines[1] housed in the original Huntly power station building, commissioned in the 1980s, of which three units (units 1, 2 and 4) are still in service[2];
- unit 5, also known as e3p, a combined cycle gas turbine (CCGT) with capacity of 405 MW;
- unit 6, also known as P40, a 48 MW open cycle gas turbine.

The Rankine units can run on a mix of gas and coal, and for the most part run on a mix of 85% coal and 15% gas, although there are some periods when the ratio falls substantially, which we assume occurs when Genesis has surplus gas to use[3].

The analysis also looked at how much gas might be consumed if coal-fired industrial process heat were to convert to gas.

The key objectives of the analysis were to:

1. estimate the additional demand for gas assuming that coal firing of the Rankine units ceases and, along with relevant coal-fired industrial heat processes in the North Is, are converted to gas;
2. understand the electricity price implications of the conversion of the Rankine units to gas;
3. estimate how much gas is required for electricity generation and how long this might be required.

In this report, section 3 looks at coal, diesel[4] and gas consumption over the last five years, the emissions over the last five years, and how the gas consumption and emissions would have turned out if coal and diesel were replaced by gas.

Section 4 provides key background information on Energy Link's Price Path, including the rationale for retaining gas-fired peakers over the entire forecast horizon.

Section 5 covers the fossil fuel consumption for electricity generation in scenarios taken from our January 2023 Price Path, and how these would change if the Rankine units only burned gas through to their assumed retirement date in each scenario.

Section 6 covers the gas supply forecasts used in the Price Path and looks at whether there is likely to be sufficient gas available over the Price Path's forecast horizon.

[1] Water is heated in boilers to produce steam, which is then put through turbines connected to generators.
[2] Unit 3 was retired some years ago.
[3] In reality, a switch to all-gas at the Huntly Power station might lead to more gas being consumed at e3p or P40. But for the sake of this analysis, we assumed the extra gas would all be burned in the Rankine units.
[4] The Whirinaki power station near Napier burns diesel.

Section 7 describes reruns of the Price Path Base Case scenario with the Rankine units burning a coal-gas mix, or 100% gas, under three different carbon price scenarios, to estimate how electricity prices might change if the Rankine units were to only burn gas.

Finally, section 8 reviews publicly available data for coal-fired industrial process heat and makes an estimate of how much emissions might reduce if some of this immediately converted to gas.

Unless otherwise stated, all dollar values are New Zealand dollars in nominal terms.

With the exception of section 8, all emissions and emissions reductions shown in this report are emissions from electricity generation.

We acknowledge the assistance of staff at Genesis Energy, who were consulted on some of the details concerning the operation of the Huntly power station. This assistance does not imply an endorsement of this report.

2 Summary

Since 2018, a combination of a few dry periods, along with reductions in gas supply and corresponding increases in gas prices, have caused the proportion of coal-fired thermal generation to increase relative to gas-fired thermal generation; from 2019 to 2021 total emissions from gas and coal-fired generation averaged 4,417 kt per annum compared to 3,553 kt per annum on average for 2017 and 2018.

If the Rankine units had burned only gas during these years, instead of its current mix of coal and gas, emissions from electricity generation are estimated to have been 7.0% lower in 2017, rising to 25.8% lower in 2021. The total estimated reduction in emissions for the five years 2017 to 2021 would have been 3,543 kt, assuming all other things remained the same.

The Price Path assumes that gas-firing remains in the market to cover dry periods and to help meet peak demand, through to the end of the forecast period. The known alternatives are either too speculative, too uncertain, or otherwise unlikely to be in place in time to significantly displace gas-firing before the mid-2030s.

Three scenarios from across the Price Path showed that up to 18 PJ of additional gas would be required in a severe dry year to run the Rankine units if it were to change strategy immediately to only run on gas, and up to 9 PJ of additional gas on average across all inflows; 18 PJ is 47% of the average annual gas consumption for electricity generation (2017 to 2021). The corresponding reduction in emissions from a shift from coal to gas generation, until the Rankine units are assumed to retire in 2029, would be up to 1,141 kt on average.

The Huntly coal stockpile currently holds around one million tonnes, and this might need to be reduced ahead of a switch to being gas-only, to avoid saturating the relatively small domestic coal market. If we assume it is reduced by 500 kt, then emissions would reduce by up to 558 kt on average through to 2029.

The emission reductions would be much larger if drier periods actually prevail over the forecast period, and much less if wetter periods prevail.

In the low demand scenario in which Tiwai closes in 2025[5], the Rankine units are assumed to retire at the end of 2024 (four years earlier than the date assumed in the medium and high demand scenarios), and the reduction in emissions would therefore be correspondingly smaller, less than 100 kt on average. If the coal stockpile is reduced before the all-gas change, then the emission reduction is zero on average.

Table 1 shows key assumptions in each of the three scenarios for the thermal generation fleet.

[5] The combined weighting given to Tiwai remaining after 2024, across all scenarios in the Price Path, is 71%.

Table 1 – Key Scenario Assumptions

Scenario	Electricity Demand in 2037/38	Rankine Units Retire	e3p Retires	Additional Gas-peaking Capacity Built
Low Demand to 2027	46 TWh	2024	2033	200 MW, 2034/35
Medium Demand to 2030	50 TWh	2029	2037	50 MW, 2036/37
High Demand to 2030	54 TWh	2029	2037	200 MW 2029/30 and 120 MW 2032/33

Table 2 shows the average annual emissions that would result from the Rankine units burning their current mix of coal and gas, versus converting immediately to all-gas operation. In each scenario, the averages are taken across all inflow sequences modelled in the low, medium and high demand scenarios. The 500 kt coal column shows the average emission reduction if the Rankine units converted to all-gas operation after running the coal stockpile down by 500 kt to avoid dumping onto the domestic market. In dry years, the emissions and the gas consumption would be much higher than the averages, so the additional gas column shows how much additional gas would be required in the worst-case inflow sequence.

Table 2 – Summary of Emissions Scenarios, Maximum Gas Consumption

Scenario	Rankine units Coal-gas (kt)	All Gas Rankine units (kt)	% Reduction	500 kt coal Rankine units (kt)	% Reduction	Additional Gas Required Per Annum (PJ)
Low Demand to 2027	3,777	1,827	2.6%	3,777	0.0%	11
Medium Demand to 2030	11,162	10,289	7.8%	10,924	2.1%	16
High Demand to 2030	13,054	11,913	8.7%	12,496	4.3%	18

If the Rankine units were to burn only gas, then the Price Path gas scenarios suggest this could be available under most scenarios for the future of gas production, albeit coming entirely from development drilling in existing fields. To achieve this, existing gas producers must continue to invest in the maintenance and development of existing producing fields, which may or may not occur under the regulations currently applying to the upstream gas sector.

If the Rankine units were to convert to gas-only operation, this might impact average spot prices. To test this, three versions of the Price Path Base Case with Tiwai remaining were run, each with a different carbon price path but with the Rankine units burning a coal-gas mix, and then rerun with them burning only gas. The impact on spot prices on average was small, to the point of being at 'noise level', although under more extreme inflow scenarios the prices would be more significant. These reruns assumed the price of coal falls from recent highs down to USD $125 per tonne, which is still higher than the pre-Ukraine war average of around USD $80 per tonne (so coal prices could fall even further in future), and this result illustrates why coal is burned in the Rankine units; it was cheaper to burn coal than to burn gas.

Switching away from coal-firing at the Rankine units would significantly reduce emissions from the electricity sector, but this would require gas to be available at a price competitive with coal, after taking into account the relative costs of carbon, and the need for gas supply to the Rankine units to be relatively flexible.

The NZ Battery team recently released its estimates of the cost and timing of the Lake Onslow pumped hydro storage project, which at $16 billion and at least a decade from today, strongly reinforces the need to retain gas-fired generation through to the mid-2030s, and longer if there are construction delays. Onslow's price tag will also make it more difficult to get across the line than previously thought[6], given that other options such as large-scale storage of green hydrogen might become available over time.

[6] NZ Battery's initial estimate was $4 billion. We understand the $16 billion estimate includes some, but not all, of the transmission build required along with Onslow.

Our assessment of the better, cheaper and hence more likely strategy for taking electricity supply toward 100% renewable energy, and for reducing electricity-related emissions, is to:

- retain gas-fired generation into the 2030s and beyond, to provide dry year and peaking support;
- switch the Rankine units away from burning coal as soon as possible, which could mean burning 100% gas or possibly switching to wood pellets at some point in the future[7];
- convert all geothermal stations to reinject CO_2 (assuming that current trials show this is economically feasible).

Switching the Rankine units away from burning coal will probably require the involvement of government, e.g. in underwriting gas supplies, and in building additional gas storage facilities to provide for additional flexibility in gas off-take at the Huntly Power station, which is in turn required to allow the Rankine units to operate as flexibly as they do now when burning coal. There is a precedent for government involvement: the e3p CCGT at Huntly was commissioned in 2007 and the government of the day underwrote the gas supply for the station.

In addition, the Gas Transition Plan the government is currently working on needs to ensure that gas is available in sufficient quantity and at a reasonable price through to the second half of the 2030s, and possibly longer depending on whether Onslow is built, or on what other alternatives become technically and economically feasible over time. As the nation becomes ever more reliant on electricity, as transport and industry electrifies, one thing is certain: the need to 'keep the lights on' and to 'keep the wheels turning' will only become more pressing, in the context of electricity supply. The only cost-effective way to do this under current conditions, and for at least the next decade, is to retain fossil-fuelled generation for dry years and winter peaks, adding additional gas-peaking capacity as and when required. And although other means of meeting peaks will develop in the medium term, e.g. grid-scale batteries, finding alternatives to managing dry years will take longer.

Most of the 21 PJ of coal burned for process heat in industry in New Zealand is burned in the South Is, where there is no piped natural gas. Total North Is coal consumption for process heat was estimated as 6 PJ in 2021. Assuming the New Zealand overall proportion of process heat for intermediate and high temperature applications, the most likely to switch to gas, applies equally in both islands, this leads to an estimate of 90 kt per annum of emission reductions if roughly half of North Is coal-fired process heat were to convert to gas.

If coal was no longer burned at the Huntly power station, and half of the North Island's coal-fired industrial process heat was converted to gas, the total reduction in emissions, up to and including 2030, would be 1.77 million tonnes under the high demand scenario, when averaged across all historical inflow sequences.

3 Historical Emissions from Fossil-fuelled Generation

The following three charts show historical data for oil-fired generation, coal-fired generation and natural gas-fired generation; energy output in GWh, fuel consumption in PJ, and emissions in kilotonne (kt) CO_2[8]. The data is sourced from the MBIE Energy in New Zealand dataset for 2022 and from the latest edition of MBIE's Energy Quarterly dataset[9]. Fuel data is available to the Dec-22 quarter (Q4) but generation data is only available to the Sep-22 quarter.

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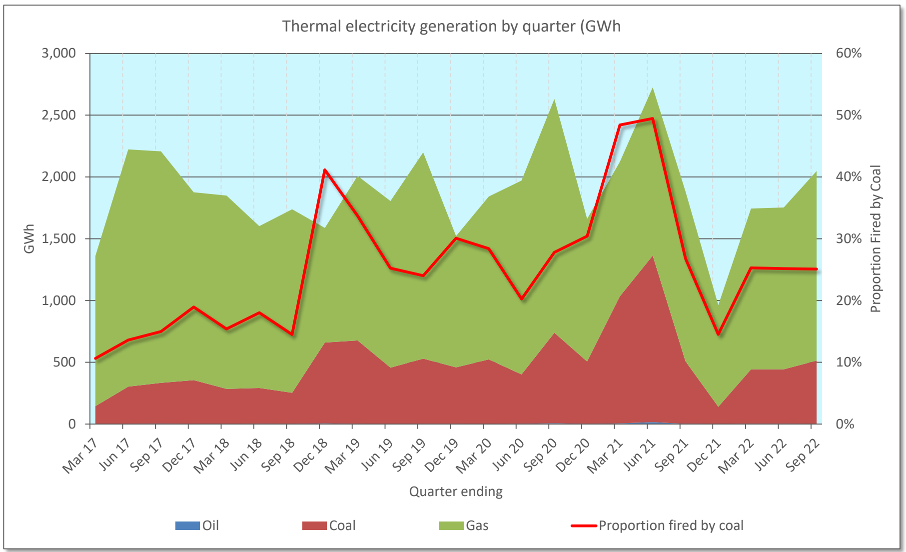
[7] We don't have enough information to estimate when pellet-burning might become an option on a sufficiently large scale, if at all.

[8] The emissions are actually for CO_2-equivalent, but the vast majority of the emissions are CO_2.

[9] The data includes energy, fuel consumption and emissions from certain large cogeneration (cogen) plant. Cogen that is primarily for use on-site is incorporated in the industrial data, and not included in the following charts and tables. Other cogen is included, but the majority of the coal and gas data is for generators that are not cogen. However, the inclusion of this other data does produce in apparent anomalies in the data, for example in Dec-21 when coal-fired generation is non-zero but coal consumption for generation is zero.

Figure 1 – Quarterly Generation Output of the Thermal Sector Mar-17 to Sep-22[10]



The quarterly thermal energy output varied over the period from a minimum of 963 GWh in the Dec-21 quarter to a maximum of 2,725 GWh in the Jun-21 quarter, with standard deviation of 20% relative to the average output: this highlights the fact that thermal output varies substantially over quite short periods as the hydro lake levels change relative to expected or average levels. In the Jun-21 quarter New Zealand's total storage was near all-time lows for that time of year, but in the following quarter storage was near all-time highs; which is reflected in the amount of thermal generation in these quarters[11].

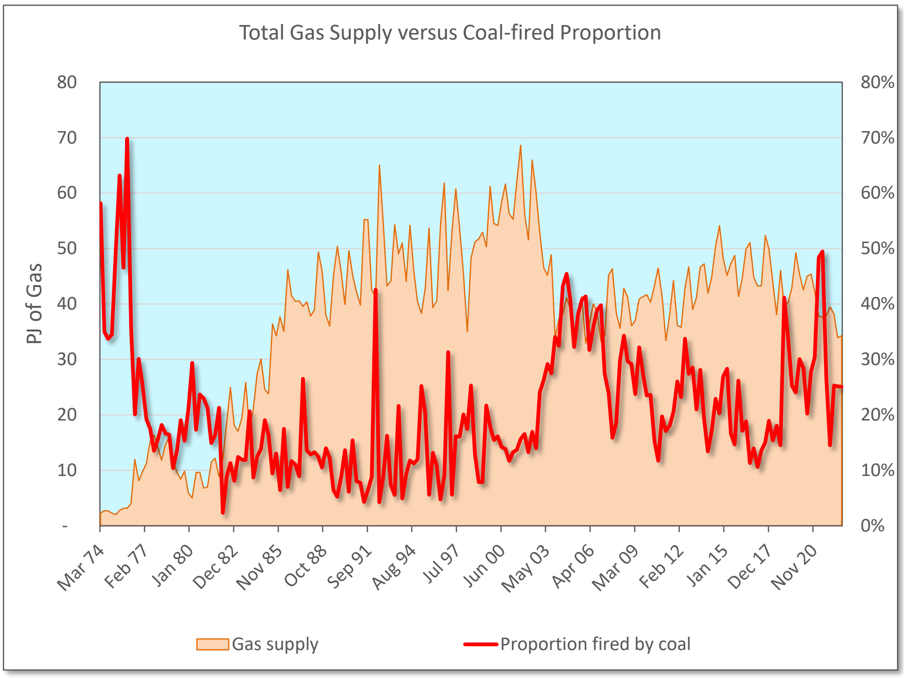
Figure 1 also shows the proportion of the thermal energy generated by coal-fired thermal generators, which varied from a low of 11% in the Mar-17 quarter, to a high of 49% in the Jun-21 quarter. However, the more important take-away from this curve is that the average amount of coal-fired generation increased from the Dec-18 quarter due to outages at the Pohokura gas field, which were repaired, but also an early run-down of Pohokura which commenced in May of 2020.

But perhaps Mar-17 through Sep-18 were quarters of high inflows?

We have data back to the Mar-74 quarter, shown in Figure 2 below. This covers a long period, with 73 quarters in the period before the electricity spot market commenced operations in October of 1996, and includes a lot of noise due to hydro inflows, changes in operating modes of large gas consumers amongst it. But notwithstanding, the negative correlation (-0.33) is clear, and of particular note is the increase in the coal proportion after Sep-02, followed by a series of years in which the coal proportion generally fell while gas supplies increased, and then late in 2018 the coal proportion rose sharply as gas supply fell.

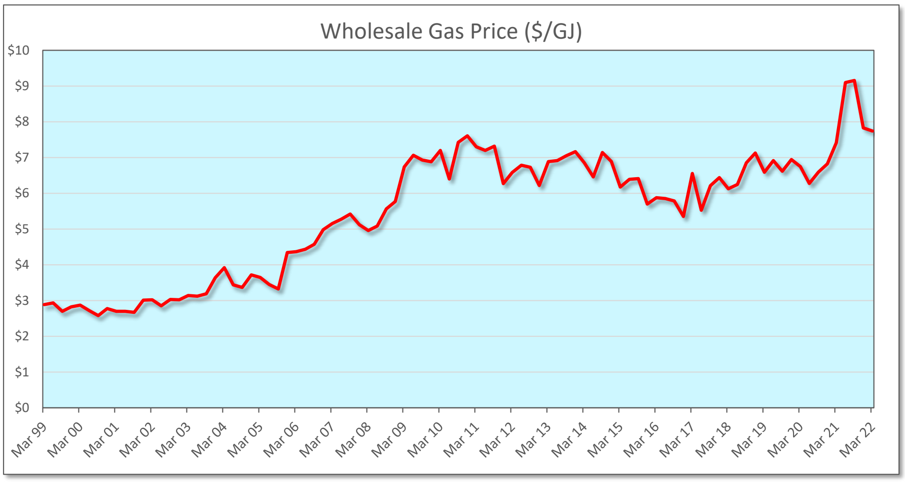
[10] The oil emissions are from diesel-fired generation at Contact Energy's Whirinaki power station.
[11] The Dec-22 quarter was also very wet, and when available, the data will show another quarter of very low thermal generation.

Figure 2 – Total Gas Supply versus Coal-Fired Electricity Generation



We do have to be careful in drawing conclusions from Figure 2 because gas supply fell after Sep-02 because its price rose sharply, which can be seen in Figure 3[12], following a redetermination of the reserves remaining in the Maui field. The average wholesale gas price series is applicable to generators[13], and we can see that it peaked initially in 2011 then fell through to the start of the Pohokura issues late in 2018, after which it rose and then hit an all-time high in 2021.

Figure 3 – Wholesale Gas Price



The physical capacity to supply gas affects the sale price as one would expect, but we can now see that what is more important, for our purposes, is the relative cost of coal and gas for electricity generation. Genesis Energy has a choice at the Rankine units; to burn coal or burn gas, or a mixture of the two. A key driver in the decision is the relative cost of the two fuels. So, if we go back to 2001 when the gas price was

[12] Most wholesale gas is sold under medium to long-term contracts, so it takes time for the average across all contracts to respond to changes in a minor proportion of contracts. The MBIE price data for gas is only available from the Mar-99 quarter.

[13] The actual price paid by generators in any particular period may differ due to the influence of longer-term gas supply contracts.

around \$3/GJ, with no carbon pricing applicable, the indifference price[14] for coal was USD \$19 per tonne[15]. By 2009 the wholesale gas price was \$7/GJ which equates to a coal price of USD \$82 per tonne, with Indonesian coal available at that time for around USD \$50 per tonne.

The key conclusion here is that the choice between coal and gas at the Rankine units is driven largely by the availability and price of domestic gas relative to the cost of sourcing coal from Indonesia. Nowadays, the indifference price analysis must also take account of the relative cost of carbon for each fuel, with the carbon cost of coal being 80% higher than it is for gas. But the corollary of the coal-gas conclusion is that if the Rankine units are to reduce their consumption of coal relative to gas, then domestic gas needs to be available in sufficient quantity for the wholesale carbon-inclusive gas price to be closer to, and preferably less than, the carbon-inclusive cost of coal[16].

Figure 4 shows fuel consumption in PJ of fuel energy content by fuel-type, illustrating the substantial variation quarter-by-quarter, driven by the combination of demand changes and inflows into the hydro lakes. The fuel consumption in GJ per GWh of energy output is also shown on the chart. The 'heat rate' of a thermal generator is the fuel energy in GJ required to produce one GWh of electricity, so the line shows the average heat rate of the thermal fleet by quarter[17]. Each generator has a nominal heat rate, which varies with its output MW, but the average heat rate over a quarter (shown in the chart) also includes fuel required to start generators, and to raise their output to minimum safe operating levels[18].

Figure 4 – Quarterly Fuel Consumption of the Thermal Sector Mar-17 to Sep-22

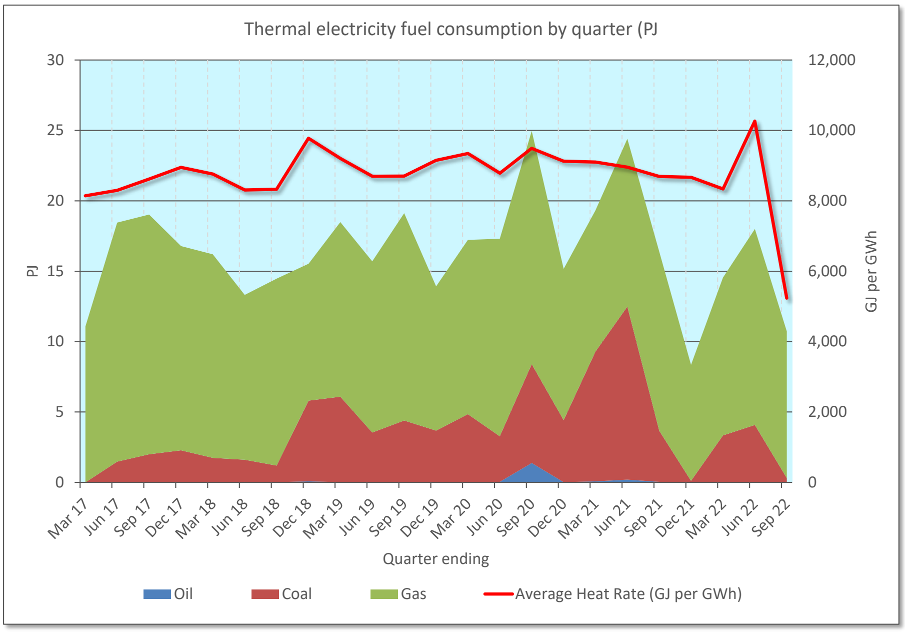


Figure 5 shows the emissions from the thermal sector, broken down by fuel type including the total emissions per GWh of generation. The coal burned in the Rankine units emits approximately 90 kt CO_2 per PJ and gas approximately 53 kt CO_2 per PJ, so as the proportion of generation fired by coal rises, so does the average kt per GJ. The oil emissions are from diesel-fired generation at Contact Energy's Whirinaki power station, which runs infrequently and typically only for a few hours at a time at most.

[14] Ignoring non-fuel short-run marginal costs.
[15] Since this is illustrative, we left out details such as the USD-NZD exchange rate at the time, assuming 0.65 throughout.
[16] Genesis Energy has hedged its carbon requirements for the next few years, but the opportunity cost of these NZUs is set by the prevailing price of NZUs.
[17] The presence of data from cogen and embedded fossil fuel-fired generation probably impacts the values shown, e.g. by making the heat rate higher than it really is.
[18] This can be quite high. For example, Genesis Energy's Huntly unit 5 (a.k.a. e3p) is a 405 MW CCGT with minimum operating level of 180 MW.

Figure 5 – Quarterly Emissions from the Thermal Sector Mar-17 to Sep-22

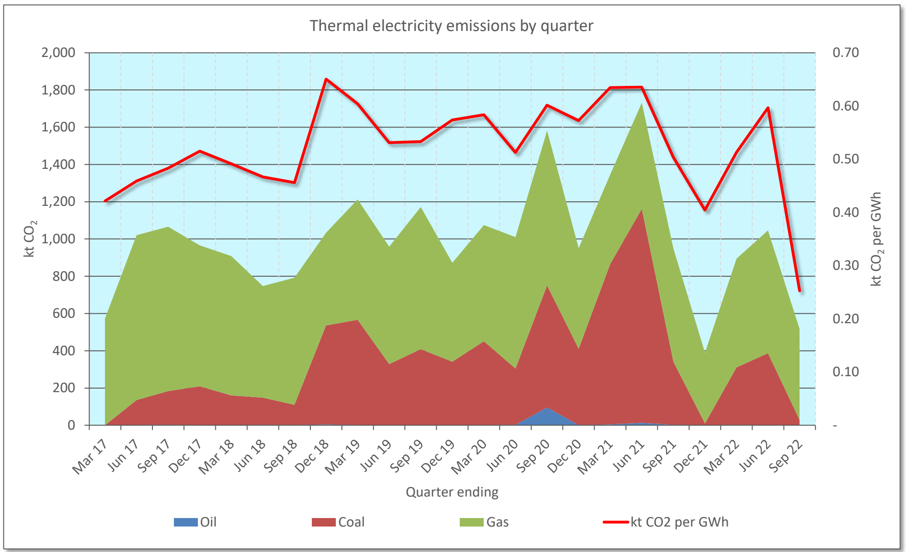


Table 3 below shows the annual emissions for calendar years 2017 to 2021, by fuel type for thermal generation, but Table 4 also shows emissions recalculated assuming the Rankine units only burn gas and Whirinaki burns gas instead of diesel. The recalculated emissions require estimates of how the average heat rate of the Rankine units, in particular, would change if they were only to run on gas.

Table 3 - Annual Emissions from Thermal Generation

Calendar year kt CO_2	Natural gas	Coal	Diesel	Total
2017	3,096	525	4	3,626
2018	2,527	946	9	3,481
2019	2,571	1,643	3	4,216
2020	2,700	1,818	99	4,617
2021	2,038	2,358	21	4,417

Table 4 – Recalcuated Annual Emissions from Thermal Generation

Calendar year kt CO_2	Natural gas	Coal	Diesel	Total	Reduction	% Reduction
2017	3,372	0	0	**3,372**	**254**	7.0%
2018	3,024	0	0	**3,024**	**457**	13.1%
2019	3,425	0	0	**3,425**	**791**	18.8%
2020	3,716	0	0	**3,716**	**901**	19.5%
2021	3,277	0	0	**3,277**	**1,140**	25.8%

Depending on the year, the reduction would be between 254 kt CO_2 and 1,140 kt CO_2 which are large numbers, and a significant minor proportion of total thermal-generated emissions. While it might be cheaper to burn coal in the Rankine units, the implications for emissions are obvious, and it is hard not to conclude that short to medium-term priority should be given to converting the Rankine units to run entirely on gas.

In 2018, Genesis Energy said it planned to "stop using coal to generate electricity except in exceptional circumstances by 2025" and to "stop using coal entirely by 2030"[19]. Since 2018, the 2030 date has not

[19] RNZ 14-Feb-18.

been mentioned often, but the company recently ran a trial of black wood pellets in a Rankine unit, which proved successful, and is now looking[20] for a suitable pellet supply in New Zealand. The company also has a strategy (called Future-Gen) to build or contract with new renewable generation, to reduce its reliance on fossil-fuelled generation. Given the time it takes to build new generation or find alternative fuels, this suggests 2030 is still a realistic date either for retirement of the Rankine units, or for conversion to renewable fuel.

Changes in gas supply and price since late 2018 have only served to raise concerns and doubts about gas supply going forward. Adding to this, is the change in government policy in 2018 which banned new offshore exploration, sending the signal to the global petroleum industry that New Zealand is "closed for business"[21] in respect of the upstream gas sector.

New Zealand is not alone in having this problem, however, and "the ESG movement, by trying to restrict investments in oil and gas ventures, is going to have the perverse effect of reducing supply even as global demand increases, thus making the price of energy rise."

New Zealand must find its own solution to the 'energy trilemma'[22] and we note that work is currently underway on the government's Gas Transition Plan which is intended to map the phasing-out of gas, but it also considers security and equity issues.

4 Background to the Price Path

The Price Path is issued to subscribers once per quarter and is Energy Link's independent forecast of spot prices at 220 nodes on the grid, currently from Apr-23 to Mar-38, with two versions of the Base Case extended to Mar-48[23]. The modelling requires simulation of the electricity market to a high level of detail, including offers for generation being submitted into the simulated market, which means that the modelling produces a large amount of relevant data in addition to forecast nodal spot prices, including:

- timing of commissioning of new generation required to meet changes in net demand[24];
- output of all modelled generators, from which fuel consumption can be calculated;
- power flows on the detailed grid used in the models, including the inter-island HVDC link;
- storage in hydro lakes and flows on the river systems below each hydro lake;
- the amount of demand response to prices along with any calls for voluntary savings[25];
- charging and discharging of modelled grid-scale batteries;
- energy stored in potential new storage facilities including batteries, pumped hydro and hydrogen-based facilities, and charging and discharging of same;
- operation of the Tiwai Pt aluminium smelter during dry periods, in line with its supply contracts;
- non-supply[26].

In order to obtain accurate[27] spot prices, the various parts of the modelled system each need to be modelled accurately. Outputs other than spot prices are also produced, including the generation output of fossil-

[20] Along with Fonterra.
[21] Andrew Jeffries, CEO of NZ Oil and Gas and John Kidd, now of Enerlytica, independently in August 2018. Kidd based his comment on discussions during while attending at the World Gas Conference in the US.
[22] Security, Equity (Access and Affordability) and Sustainability.
[23] The next Price Path is due out mid-March and will extend from Apr-24 to Mar-39 with Base Case extensions to Mar-49.
[24] Net demand change is equal to demand growth plus any plant retirements.
[25] Which might be called for by Transpower during a prolonged dry period as hydro lake levels fall.
[26] Non-supply occurs when there is insufficient generation to meet demand during a modelled period.
[27] Accurate in the sense that it the output prices are consistent with the underlying assumptions and the underlying market.

fuelled generators. We therefore have a high degree of confidence that the modelled fossil-fuelled generation used in this report is accurate.

4.1 Scenarios

The Price Path currently consists of 16 market scenarios, each one a combination of gas price scenarios (high, medium and low), carbon price scenarios (high, medium and low), Tiwai Pt assumptions (it either stays beyond the end of its current supply contract, or closes in 2025 after the current contract expires), other demand assumptions, and the costs of building new generation.

Each of the 16 scenarios has its own ‘build schedule’, which is the list of new generation that is built over the horizon of the scenario, including its location on the grid, its type (geothermal, wind, solar, gas-fired, hydro, or other), its capacity, and any other parameters required to specify the plant. As each scenario extends from Apr-23 to Mar-38 (15 years), there are 240 years actually modelled. In addition, two of the scenarios are versions of the Base Case[28], one with Tiwai remaining and one with it closing in 2025, which takes the total scenarios modelled to 270.

When a scenario is modelled, it is also run with all of the historical hydrological inflow data that we have available (currently 91 years-worth, dating back to Apr-31), giving a total of 24,750 modelled years across all 16 market scenarios. The assumption here is that historical inflows provide the best set of inflows to use for the modelling of future years.

In the following sections, a reference to the average value of some output from a scenario, is a reference to the average over the 91 inflow sequences. However, the historical inflows vary widely and hence there are prolonged periods of low inflows (dry periods) and also periods of high inflows (wet periods). During wet periods, especially as the percentage of renewable power rises, the generation required from fossil-fuelled generators is low or nil, whereas during dry periods the fossil-fuelled generation can be substantial, and certainly much higher than average. Therefore, we need to consider the range of fuel consumed by these generators, as well as the average fuel consumption and prices in each scenario.

4.2 Inflows Change

A question that often arises when modelling the electricity market in New Zealand, is how inflows might change in future due to climate change. There are two aspects to this question:

1. how will the average inflows change?
2. how will the range of inflows change?

For example, if one assumes that global warming allows more moisture to be carried in the atmosphere, then inflows might increase over time. However, it is not quite as simple as that. A recent paper[29] on this topic concluded that annual inflows would increase by 2% on average between 2020 and 2050, with summers becoming drier and winters becoming wetter. In fact, we already observe this change in timing in inflows over the last two decades, though the average inflow has not changed significantly over that period.

The paper also states that “little change in drought severity or duration is expected in New Zealand’s largest hydropower catchments over the next three decades”. In other words, dry periods are likely to be a feature into the future just as they were over the last 91 years.

This being the case, our use of 91 years of unadjusted historical inflow data is likely to lead to as good an estimate of the need for fossil-fuelled generation in dry periods as a set of climate-adjusted inflows.

[28] The Base Case is the scenario in which all inputs are ‘medium’.

[29] *Modelling climate change impacts on inflows, lake storage and spill in snow-fed hydroelectric power catchments, Southern Alps, New Zealand*, J Purdie, Centre for Sustainability, University of Otago, published in Journal of Hydrology (NZ) 61 (2): pages 151-178.

4.3 Management of Dry Periods and Peak Demand

The government established the NZ Battery project to "investigate pumped hydro against other possible solutions to New Zealand's dry year electricity problem" to reduce or eliminate reliance on thermal generation, with the proposed Lake Onslow pumped hydro scheme being the project's poster child. The project team is also looking at possible solutions based on hydrogen, flexible geothermal generation and bioenergy.

In a report recently completed by Energy Link for First Gas Group[30], we also looked at large-scale storage of green hydrogen as a solution for managing dry years, and for meeting peak demand, with 100% renewable electricity, and compared this to the Lake Onslow proposal, and to a solution proposed by the Electricity Authority's Market Development Advisory Group (MDAG).

Genesis Energy also announced last year that it is actively exploring the option of burning wood pellets in the Rankine units.

Which all raises two key questions:

1. why have we not included Lake Onslow, or one of the alternatives above, in the Price Path?
2. why have we instead chosen to continue with fossil-fuelled, primarily gas-fired, generation?

In our role as independent forecasters, we take great care not to be overly influenced by the views of others, and instead work diligently to form our own views of how the electricity market will evolve over time. In particular, we do not put any greater weight on what government or its agencies, or any other body for that matter, might propose, promote or investigate. We also take care not to be victims of the availability heuristic[31], the bandwagon effect[32], confirmation bias[33], groupthink, authority bias[34], and various other biases that we humans may exhibit to a greater or lesser extent.

Which means that just because an authority such as the government proposes or promotes an option such as Lake Onslow for pumped storage, our assessment of the likelihood of it ever being built is based entirely on what we see as the pros and cons of the proposal, along with political considerations that could lead to a government pursuing an option even if we believe it is suboptimal, or vice versa.

Focussing for the moment on Lake Onslow, which we have modelled on a number of occasions, there are several factors that make it unlikely to be built:

1. if there is a change of government at the next election, the National Party has already said it will not pursue the project;
2. it is not in the North Is, which means that the ability to get power to the North Is where it is most needed, is constrained by grid capacity;
3. it is a highly capital-intensive option[35], the cost of which could include an upgrade of the HVDC link to allow Onslow power to help meet peak demand in the North Is;
4. it is potentially environmentally destructive given its large physical size and location.

[30] The report is available in full at https://firstgas.co.nz/independent-report-finds-hydrogen-storage-best-solution-to-support-a-fully-renewable-electricity-system/.
[31] The tendency to use information that comes to mind quickly and easily when making decisions about the future, e.g. options for managing dry years and peak demand that just happen to be in the news now.
[32] The habit of adopting certain behaviours or beliefs because many other people do the same.
[33] The tendency to favour our existing beliefs.
[34] The tendency to give greater weight and assign greater accuracy to the opinions of a person in a position of authority, regardless of the context.
[35] The NZ Battery released a statement saying its estimate for Onslow's capital cost is $15.7 billion, and that it would take another three years to complete the business case and make a final investment decision, then seven to nine years to build it; if it goes ahead.

This does not mean it will not be built, it just means that we believe the likelihood of the build is not sufficiently high for us to include it in the Price Path. Even if it is built, the need for some gas-fired generation in the North Is might remain, e.g. instead of upgrading the HVDC link to meet North Is demand peaks, gas peakers could be retained as a cheaper option.

The NZ Battery team recently released its estimates of the cost and timing of the Lake Onslow pumped hydro storage project, which at $16 billion and at least a decade from today, strongly reinforces the need to retain gas-fired generation through to the mid-2030s, and longer if there are construction delays. Based on the NZ Battery estimates, fossil-fuelled generation would be retained in the market until at least 2035. In fact, they would be required for two to three years longer because, as we discovered in our modelling of Onslow, they would play a key role in helping Onslow to reach a normal operating level[36] in a reasonable time.

So even if Onslow is built, fossil-fuelled generation will be required until at least the second half of the 2030s, which is around the end of the Price Path forecast period.

If Onslow is built, even with an upgrade of the HVDC link, then our modelling shows that meeting peak demand in the North Is remains a challenge as demand grows. The MDAG scenario also retains gas-fired peakers through until the market is 100%RE, but assumes they are run on ‘green gas’, which could be biogas or green hydrogen, for example.

If large-scale storage of green hydrogen can be achieved cost-effectively then there would be a fleet of green hydrogen-fuelled peakers in the North Is to generate electricity during dry periods and periods of peak demand, as required.

While using green hydrogen in gas-fired generators may become an attractive option in future, this does not necessarily mean that existing gas-fired peakers would be capable of running on hydrogen, as generators need to be designed to burn hydrogen or, in some cases, converted to burn hydrogen.

Given that other options such as large-scale storage of green hydrogen may become available over time, our assessment of the better, cheaper and hence more likely strategy for taking electricity supply toward 100% renewable energy, and for reducing electricity-related emissions, is to:

- retain gas-fired generation into the 2030s and beyond, to provide dry year and peaking support;
- switch the Rankine units away from burning coal as soon as possible, which could mean burning 100% gas or possibly switching to wood pellets at some point in the future;
- convert all geothermal stations to reinject CO_2 (assuming that current trials show this is economically feasible)[37].

This strategy is not only low cost and capable of dramatically reducing emissions from where they are today, but over time, the options for getting to 100%RE will become clearer, and cheaper, and can be implemented progressively.

If green gas becomes available in sufficient quantity and early enough, then some or all of the gas-fired generation could be converted to burn green gas.

If the cost of grid-scale batteries falls sufficiently low, as EVs displace conventional vehicles, and as consumers develop a greater level of demand response, then eventually gas-fired generation may not be required to meet peak demand but remain focussed on providing backup for dry periods. This will not happen overnight, and will more than likely take at least a decade if not longer.

[36] The alternative would be to arrange an over-build of new renewable generation, e.g. by subsidising the build. Given New Zealand’s history of not subsidising new generation, with only two exceptions, this is unlikely.
[37] Estimated emissions from geothermal generation in 2022 are 582 kt, using MBIE generation data and 73 tonnes CO_2 per GWh (from *Greenhouse Gas Emissions from New Zealand Geothermal: Power Generation and Industrial Direct Use*, McLean et al, Proceedings 42nd New Zealand Geothermal Workshop 24-26 November 2020).

The catch, however, is that the strategy above requires continuity in the supply of gas in the right quantities, with flexible delivery, and at a reasonable price. The Price Path assumes this will be the case, because it must be the case if electricity supply is going to remain secure and reliable; one only has to look at the fall-out from the blackouts of 9th August 2021 to be reminded of the overriding importance of security and reliability. Over time, as we become reliant on electricity for transport and industry, as well as for everything we use it for today, security and reliability are set to become more important, not less.

The Price Path's retention of gas-fired generation is based on the need to retain gas-fired generation even if government intervenes in the market, e.g. by building Lake Onslow pumped storage. But our own, independent assessment is that retaining gas-fired peakers is the best way forward, given the current state of knowledge, notwithstanding the possibility of large-scale pumped storage. Which raises the question: are we assuming certain policy settings, or other measures, remain in place or are put in place?

In a submission we made to the Electricity Authority in March 2022, in response to a question concerning the transition to 100% renewable electricity and retirement of fossil-fuelled generation, we stated "Past retirements were not always signalled well in advance, because it is not always in the interests of the generator concerned to announce the retirement until they have their plans for generation expansion in place. If this continues in future, we see government intervention as inevitable. For example, e3p (Huntly unit 5) had a gas contract underwritten by the government of the day when it commissioned this unit. Notwithstanding the push to 100%RE, government will have the same incentive to ensure that key plant is kept in the market for as long as it is needed, and retired when no longer required. One only has to look at Australia to understand what mayhem sudden thermal closures create."

Our point in submitting the above was not to advocate for government intervention in the market. It was instead to emphasise the need for government and industry to work together to ensure the transition is managed effectively. The most obvious role for government here is to ensure that natural gas is available for as long as it is required to 'keep the lights on', and we note the work currently underway on the Gas Transition Plan. The plan is ultimately about phasing gas out, but it must also ensure there is sufficient gas available, with sufficient flexibility of supply (or demand response[38]) to cater to the needs of gas-fired generation, and at a reasonable price.

In addition to this, there is already a precedent for government to play a role in underwriting gas supply for the Rankine units, and if this was done again, in a way that allowed the Rankine units to switch to burning 100% gas[39], then as we will see in the following sections, the reduction in emissions from electricity generation would be substantial. Assuming the gas is available, this could be achieved quite quickly.

4.4 Plant Operation

Assumptions around the offering strategies[40] of the thermal fleet have a particularly large impact on the total consumption of fossil fuels in the Price Path. For example, e3p is a large CCGT and in its earlier years[41] it would run baseload most of the time, only being taken out for maintenance. In the last few years, however, it has moved well away from this mode of operation.

Genesis Energy stated in its annual report for FY19 that e3p had moved from being "always on" to more flexible operation, which effectively followed the lead of Contact Energy's TCC CCGT which had moved towards this mode from as early as 2013.

Our modelling of the operation of TCC, e3p and the Rankine units reflects observed behaviour, in which the plant is only offered when it is expected to run for a minimum period at a price exceeding its operating

[38] This refers to the willingness of large gas consumers to forego gas consumption when extra gas is required during dry periods. Methanex, the country's largest gas consumer has played this role in recent times.
[39] Or close to it. Alternatively, Huntly might run less, but more gas burned in e3p, at a much higher efficiency.
[40] The prices and quantities offered into the simulated market, relative to each other and relative to all other plant categories.
[41] It was commissioned in 2007.

costs. These offering strategies, in the real world, are underpinned by changes in the way that gas is contracted, having been contracted on a take-or-pay[42] basis in the past, and now on a more flexible basis.

As the percentage of renewables increases, the remaining thermal generators' operations are confined to ever shorter periods during dry periods and peaks in demand. We assume that e3p moves from its current mode of operation to winter-only mode in 2028 and to dry year-only mode in 2031 and then it retires in 2037 in the medium and high scenarios, but four years earlier in the low scenario.

As the market closes in on 100%RE, the real need for gas-fired generation becomes ever more centred on dry periods and peak demand.

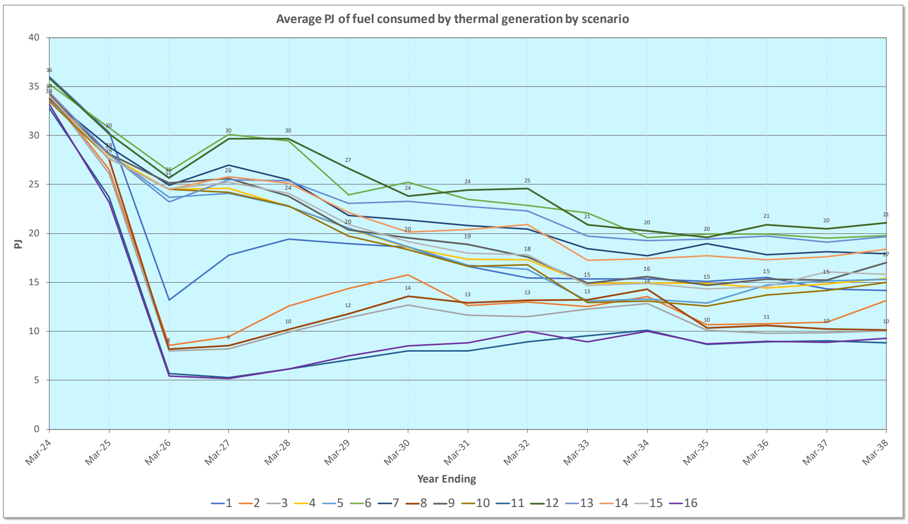
5 Forecast Emissions from Fossil-fuelled Generation

Figure 6 shows the average fuel consumed by the thermal sector, by year, for all 16 scenarios in the Price Path, where each curve is the average across the 91 inflow scenarios modelled for each of the 16 scenarios[43].

A series of dry periods in the last few years led to higher-than-average thermal generation, and in the next few years there is a substantial amount of new renewable generation coming on line, which will be before the higher rates of demand growth predicted for EVs and electrification of process heat start to make their presence felt: 167 MW in 2023/24, 320 MW in 2024/25, and 120 MW in 2025/26[44].

As a result, average fuel consumption in the first year is lower[45] than the average of the last few years and fuel consumption falls in all scenarios in the first three years[46].

Figure 6 – Thermal Sector Fuel Consumption by Price Path Scenario



[42] Under a take-or-pay gas contract, the user must pay for the gas whether it uses it or not. In this case the gas price is not a short-run marginal cost (SRMC), and so the SRMC of the plant is low, based only on non-fuel costs such as water treatment, and today also on the cost of carbon. This makes it economic to have the plant running even when spot prices are below the plant's fuel-inclusive SRMC.
[43] The two versions of the Base Case, one with Tiwai remaining indefinitely and one with it closing in 2025, extend an additional 10 years to Mar-48.
[44] This includes Mercury's 72 MW Kaiwaikawe windfarm in Northland, the output of which is contracted to Genesis Energy, but is currently held up in the consenting process.
[45] Due to the contribution of wet years to the avarages.
[46] Inclusion of cogen and embedded generation in the historical data also overestimates the consumption due to the generators modelled in the Price Path.

In order to explore the range of emissions from the thermal sector, we chose three scenarios: Base Case with Tiwai remaining (scenario 9, "medium scenario"), scenario 12 ("high scenario") and the Base Case with Tiwai closing in 2025 (scenario 8, "low scenario"). The naming of the scenarios primarily reflects the fuel consumption, but underlying this is the demand in each scenario, so the low scenario, with Tiwai closing in 2025, has the lowest demand, and the high scenario has the highest demand.

Two scenarios (11 and 16) have lower fuel consumption than the low scenario but their combined weighting in the Price Path (probability) is only 3.5% whereas the low scenario used in this report has a weighting of 9%. The medium scenario has a weighting of 21% and scenarios 6 and 12, which have similar fuel consumption, have a combined weighting of 6.5%, i.e. we currently assess scenarios with higher demand as being more likely than scenarios with lower demand due to the weighting given to Tiwai remaining[47] and to forecast electrification of transport and process heat.

In the low scenario, Tiwai performs a staged close-down in 2025, the year after its current supply contract terminates. There is some additional demand growth spurred by lower prices, but this scenario does not include new developments such as the Southern Green Hydrogen project, so the demand for thermal generation falls dramatically. Hence, we assume the Rankine units close completely at the end of 2024. The TCC also closes (which is programmed by Contact Energy to happen anyway in 2024) leaving e3p and the existing gas-fired peakers to run during dry periods and winter peaks. e3p is retired in 2033 and a new 200 MW gas-fired peaker is built at Huntly in 2034/35 as demand grows.

The Price Path scenarios assume the Rankine units continue to burn a mix of coal and gas, but the emissions were recalculated assuming it only burned gas; the results for annual emissions from the thermal sector are shown in Figure 7 below. On the left are the emissions with the Rankine units burning coal and gas, and on the right are the emissions with them burning only gas. As the Rankine units retire in 2024, the emissions only differ in the first two years, but in these two years they are lower on average with the Rankine units burning only gas.

Figure 7 – Low Scenario Emissions with the Rankine units Coal-gas and Gas-only

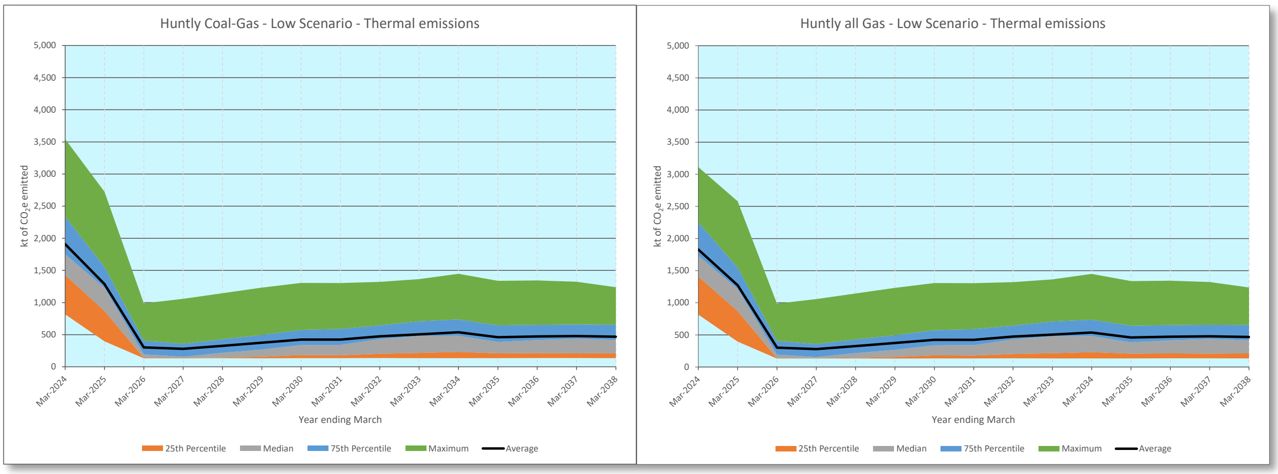


Figure 8 shows the same results for the medium scenario, i.e. the Base Case version in which Tiwai remains indefinitely. The Rankine units retire in 2029 in this scenario, and the average and particularly the maximum emissions are higher with the Rankine units burning the coal-gas mix. In this scenario, total demand net of embedded solar reaches 50 TWh per annum in 2037/38.

We assume that e3p changes its operating mode in the medium and high scenarios, as noted in section 4.4, from its current mode of operation to winter-only mode in 2028, and to dry year-only mode in 2031. In winter mode it is offered at a price which ensures it only runs when it can reasonably expect to run for at least several days at any time. In dry year-only mode it is offered at a price which ensures it only runs

[47] The combined weighting given to Tiwai remaining after 2024, across all scenarios, is 71%.

when it can reasonably expect to run for an extended period when the hydro storage lakes need to conserve storage due to low and falling lake levels.

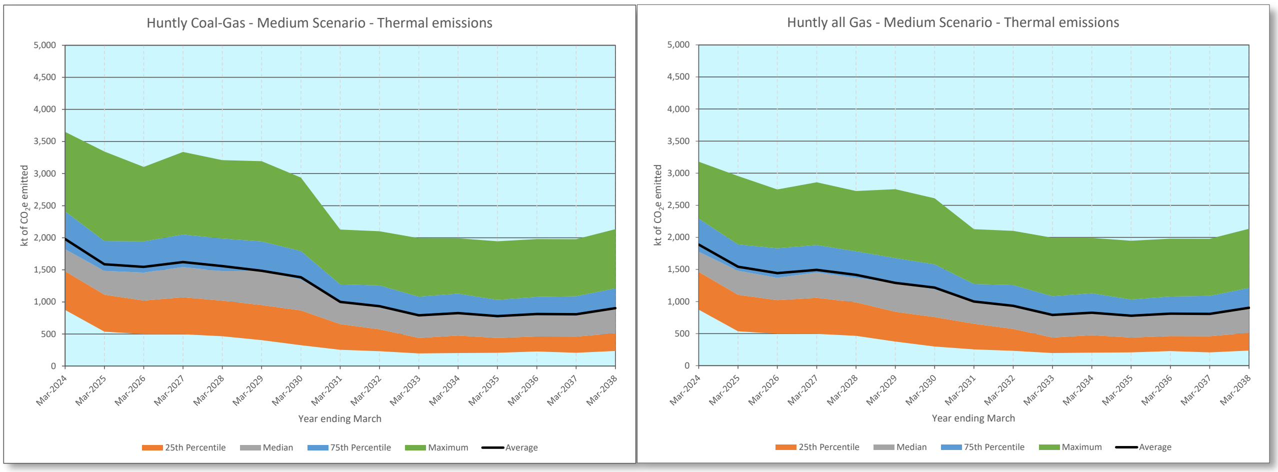
By 2037, e3p is 31 years old. As a CCGT, when compared to open-cycle gas turbines (OCGTs, or simply gas peakers), it is relatively inflexible: it can take several hours to start from cold, and can only operate down to 180 MW once running. As the percentage of renewables increases, however, the opportunities for e3p to run continuously become fewer and fewer, and its fixed operating costs start to dominate its total costs to the point where it is no longer economic to retain it in the market.

On the other hand, the ideal gas-fired plant for a market which is very high (90%+) in renewables, can be started and taken to full output quickly, and can also run efficiently for long periods when required during dry periods. All scenarios assume that the existing gas-fired peakers are retained in the market for the long term:

- Huntly P40 48 MW Gas-fired
- Stratford Peaker 200 MW Gas-fired
- McKee Peaker 100 MW Gas-fired
- Junction Road 100 MW Gas-fired
- Whirinaki 155 MW Diesel-fired[48]

In the medium scenario, an additional 50 MW of gas-fired peaking capacity is built in 2036/37, later than in the low scenario because e3p remains longer[49].

Figure 8 – Medium Scenario Emissions with the Rankine units Coal-gas and Gas-only



There is a marked 'hump' in thermal emissions in this scenario and in the high scenario, from 2026/27 to 2029/30, which is due to variations in the rate at which new generation is built relative to demand growth. The Price Path calculates build schedules using a method designed to simulate how existing and new market participants build new generation, based primarily on the cost of new generation relative to price expectations. Just as in the real market, this process does not give a perfect match of new generation to changes in demand so, for example, there is a relative surplus of new generation built in the first two years, which depresses spot prices below today's levels, which then leads to a lag in building new generation,

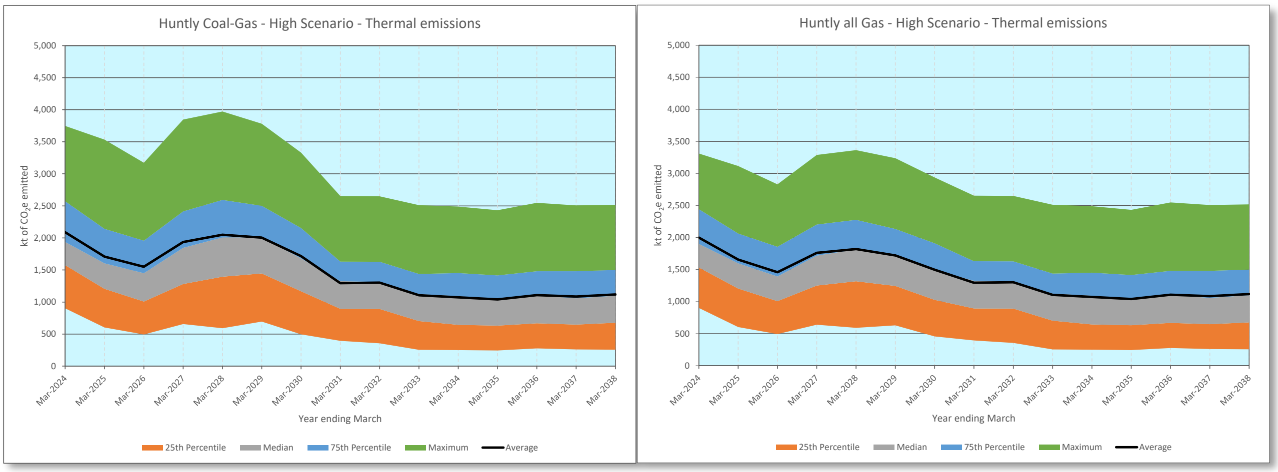
[48] Whirinaki could be gas-fired, but its location in the Hawkes Bay means the gas-supply network is unable to supply sufficient gas for it to operate at full output. There is diesel storage on site, but only enough for it to operate for periods measured in hours. Whirinaki is effectively only available for emergency use.
[49] Each scenario has a unique combination of demand and new generation, producing different price forecasts, so the timing of new plant build is not directly comparable between scenarios, e.g. in terms of demand growth. The medium scenario is actually run through to March 2049, and more gas-fired plant is built in this scenario beyond the time horizon used in this report.

until prices rebound. Further out, these imbalances tend to become smaller, but can still be significant when large thermal plant retires.

Figure 9 shows the same results for the high scenario, in which Tiwai remains indefinitely and there is also substantial demand growth from industry, with total demand (net of embedded solar) reaching almost 54 TWh per annum by 2037/38[50]. The Rankine units retire in 2029 in this scenario, and the average and particularly the maximum emissions are higher with the Rankine units burning the coal-gas mix.

In the high scenario, which has the highest demand of the three scenarios, an additional 200 MW of gas-fired peaking capacity is built in 2029/30, and a further 120 MW in 2032/33.

Figure 9 – High Scenario Emissions with the Rankine units Coal-gas and Gas-only



The chart data is also shown in the three tables below, but with additional information including the total reduction in emissions from running only on gas, and the reductions if the switch to all-gas was only made after reducing the coal stockpile at Huntly, which at the end of 2022 was reported to be one million tonnes.

The "500 kt coal Rankine units" columns show the emissions if the Rankine units use half of the current stockpile before retiring. One million tonnes is enough to keep one 250 MW unit at the Rankine units running on full output for one entire year, so in the context of a major dry year event, it is likely this coal would be used relatively quickly. But not using some of the coal in the stockpile would leave Genesis Energy with the risk of being left to sell on the domestic market, which comprises around 1.4 million tonnes for uses other than firing the Rankine units. Burning 500 kt before converting fully to gas-firing would be a risk mitigation strategy, intended to avoid being left with having to sell the coal stockpile residual at below cost.

The value of 500 kt was chosen somewhat arbitrarily, however the domestic market for coal is small, and even disposing of 500 kt of surplus coal could prove difficult, especially if its purchase cost was higher than domestic coal prices. If the Rankine units are to run only on gas, then disposing of surplus coal would be a significant undertaking in its own right, potentially even requiring a large write-down in the value of the coal in the stockpile.

In the case of the low scenario, the 500 kt of coal is not used on average prior to retirement, although it does get used in some drier years in this scenario. But ignoring the stockpile issue, the total reduction is of the order of 97 kt (2.6%) on average if the Rankine units were to convert to all-gas from April 2023.

[50] This value is similar to the total electricity in the Climate Change Commission's demonstration pathway.

Table 5 - Annual Emissions for the Low Scenario

March kt CO_2	Rankines Coal-Gas	All Gas Rankines	% Reduction	500 kt Coal Rankines	% Reduction
2024	1,909	1,827	4.3%	1,909	0.0%
2025	1,288	1,272	1.2%	1,288	0.0%
2026	302	302	0.0%	302	0.0%
2027	279	279	0.0%	279	0.0%
Totals	**3,777**	**3,680**	**2.6%**	**3,777**	**0.0%**

With the higher demand in the medium scenario the 500 kt of coal would be used on average within the first four years, giving an overall reduction of 238 kt or 2.1%. If the conversion to all-gas is immediate then the reduction is 873 kt or 7.8%.

Table 6 - Annual Emissions for the Medium Scenario

March kt CO_2	Rankines Coal-Gas	All Gas Rankines	% Reduction	500 kt Coal Rankines	% Reduction
2024	1,980	1,887	4.7%	1,980	0.0%
2025	1,587	1,541	2.9%	1,587	0.0%
2026	1,545	1,443	6.6%	1,545	0.0%
2027	1,621	1,494	7.8%	1,614	0.4%
2028	1,558	1,415	9.1%	1,508	3.2%
2029	1,486	1,290	13.2%	1,391	6.4%
2030	1,385	1,218	12.1%	1,298	6.3%
Totals	**11,162**	**10,289**	**7.8%**	**10,924**	**2.1%**

The high scenario with the 500 kt constraint would on average produce a reduction of 558 kt within the first three years or 4.3%. If the conversion to all-gas is immediate then the reduction is 1,141 kt or 8.7%.

Table 7 - Annual Emissions for the High Scenario

March kt CO_2	Rankines Coal-Gas	All Gas Rankines	% Reduction	500 kt Coal Rankines	% Reduction
2024	2,088	1,998	4.3%	2,088	0.0%
2025	1,709	1,657	3.1%	1,709	0.0%
2026	1,551	1,459	5.9%	1,549	0.1%
2027	1,935	1,761	9.0%	1,888	2.5%
2028	2,050	1,820	11.2%	1,919	6.4%
2029	2,005	1,720	14.2%	1,796	10.4%
2030	1,716	1,498	12.7%	1,548	9.8%
Totals	**13,054**	**11,913**	**8.7%**	**12,496**	**4.3%**

6 Gas Supply

If the Rankine units were to convert immediately to all-gas firing, the question arises: would there be sufficient gas to make up the difference?

The maximum annual coal consumption in the high scenario is just over 18 PJ, which means that up to another 18 PJ of gas would need to be found in order to supply this (47% of the gas consumed for electricity generation in the five years 2017 – 2020). The highest average annual consumption in 2027/28 is just over 9 PJ, i.e. up to 9 PJ per annum on average would be required.

As part of the Price Path modelling, a gas price path is calculated through to 2041, using a Monte Carlo simulation that produces 1,000 scenarios for gas price, reserves, production and so on. Key inputs include the price elasticity of gas demand including Methanex, the long-term drilling success rates of exploration and development drilling, and the field size distribution for on and offshore Taranaki. The outputs of the simulations include gas price, Methanex's gas consumption, total consumption, gas reserves and annual production.

Figure 10 shows the latest outputs for annual production and P50 (proven and probable) reserves, and shows that both fall steadily over time, on average. Although there are scenarios in which large new discoveries are made, these are few and far between, and effectively ignored for the purposes of the Price Path. Methanex, as the largest gas consumer, plays a significant role in developing gas resources by underwriting investment via long-term gas supply contracts, so large increases in production are only likely to occur if Methanex were to expand its operation significantly in New Zealand.

Figure 10 – Forecast Gas Reserves and Production

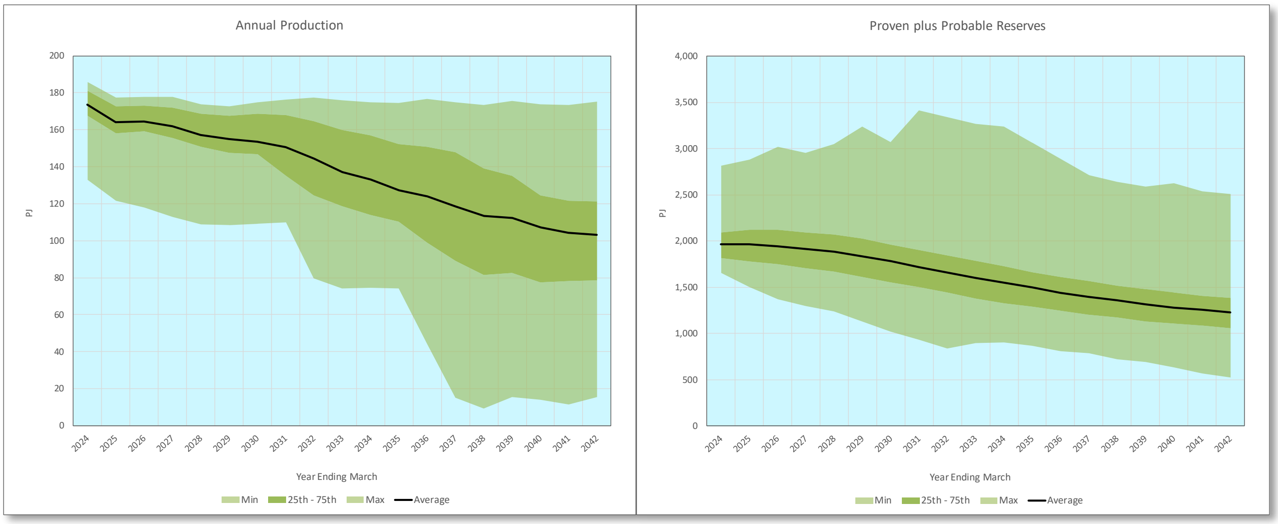
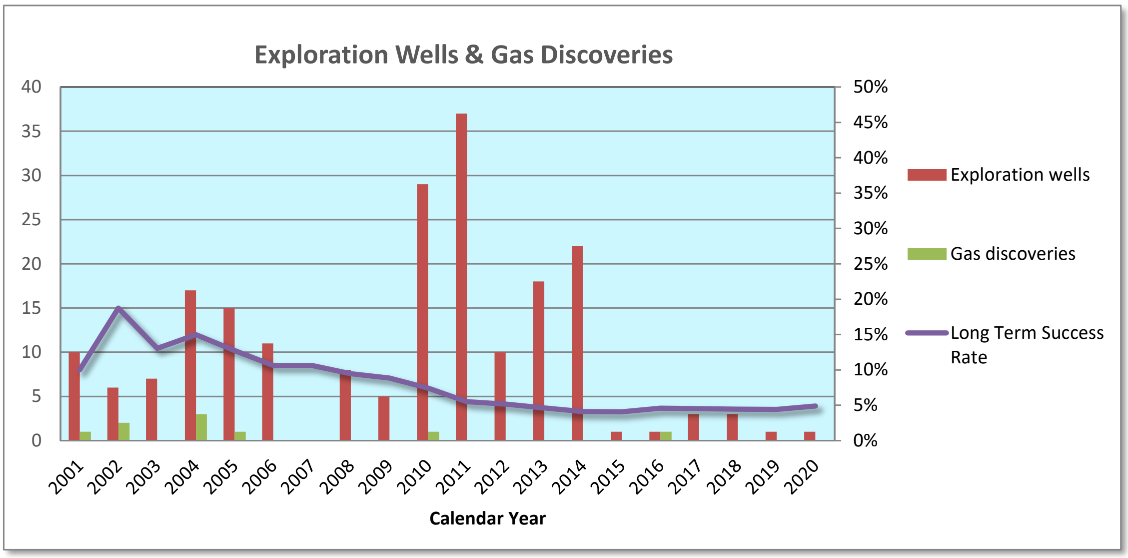


Figure 11 shows drilling statistics to 2020 for exploration wells, which are wells drilled to find new gas fields, as opposed to wells drilled to extend, either in area or in time, existing producing fields. Despite extensive exploration through to 2014, there were only two discoveries since 2005, and the long-term success rate for exploration drilling has fallen to under 5%.

This was the case with or without the ban on new offshore exploration, so when the ban was introduced in 2018, we did not make large adjustments to the inputs into our gas price path. Ban or not, we were already highly reliant on extending the life of existing production fields. What the ban appears to have done, however, is to make New Zealand less attractive for entry into the market by oil and gas companies that are new to the country (see last few paragraphs of section 3). The corollary of this is that we are now almost totally reliant on existing players to continue investing, for as long as required, to keep the gas flowing. For the purposes of the Price Path, we have to assume gas producers continue to invest in developing new supply. Whether this happens or not, given current policy settings, could be debated, but if the lights are to stay on and the wheels are to keep turning, then there really is no alternative in the medium term.

Figure 11 – Exploration Drilling Statistics



Returning to the charts in Figure 10, we can see there are scenarios at the lower end where procuring an additional 9 PJ of gas for the Rankine units, and up to 18 PJ in a very dry year, could be difficult and might require, as was the case last year, Methanex and possibly other large gas consumers to reduce consumption for a period, at an economic cost including reduced profits, and reduced economic activity in their respective communities.

But for the most part, if the appropriate level of investment is made in maintaining gas production, then under the large majority of scenarios there will be sufficient gas available if the Rankine units were to immediately convert to 100% gas-firing.

These charts do not illustrate, however, the issue of gas deliverability. Gas supply for electricity generation is increasingly driven by plant operating intermittently in baseload or firming modes, which is not necessarily supported by the minimum level of investment required to keep gas flowing[51]. Flexible gas supply requires either additional investment in the fields themselves, or investment in gas storage. We already have gas storage at First Gas' Ahuroa gas storage facility[52] and additional storage is under investigation[53], so there are signs that storage could increase in future.

Taken overall, as long as existing gas producers continue investing in their producing fields, and as long as sufficient gas storage is available, there should be enough gas available to allow the Rankine units to convert to 100% gas-firing.

But the Rankine units are relatively flexible, and having a large coal stockpile at Huntly caters to this flexibility. Thermal generation will have to be more flexible as time goes on as the percentage of renewable generation increases. On the other hand, gas wells tend to function best when gas draw-off is relatively steady. To add flexibility to gas supply, gas storage was added by converting the depleted Ahuroa gas field into a gas storage facility, which entered service in the early 2010s at a cost of $177 million, and is today capable of storing in excess of 10 PJ of gas[54]. But if the Rankine units were to run only on gas, then more gas storage would be needed. For example, Genesis said in December 2020 that 20 PJ of additional gas storage would be desirable. The cost of this would be in the hundreds of millions of dollars.

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[51] The minimum level of investment would typically be based on a well operating at capacity factor of 70% or higher.
[52] The storage at Ahuroa was recently downgraded due to water ingress, which will take time to partially reverse.
[53] New Zealand Energy Corporation and L&M Energy are investigating a gas storage project at the Tariki gas field, targeting at least 10 PJ of storage.
[54] After upgrades, it was capable of storing up to 15 PJ of usable gas, but recent water ingress has reduced storage to between 10 and 12 PJ.

In our scenarios, of course, this would only be required for the Rankine units until 2029 and there would be many years in which gas consumption would be low or very low due to an abundance of renewable electricity. But beyond 2029, the retirement of the Rankine units would of course lead to additional gas consumption at other stations including e3p, which would also benefit from an increase in gas storage, e.g. to help supply gas peakers. In fact, Todd Generation, who own two gas-fired peakers in Taranaki, are reported to have contracted for gas storage at Ahuroa.

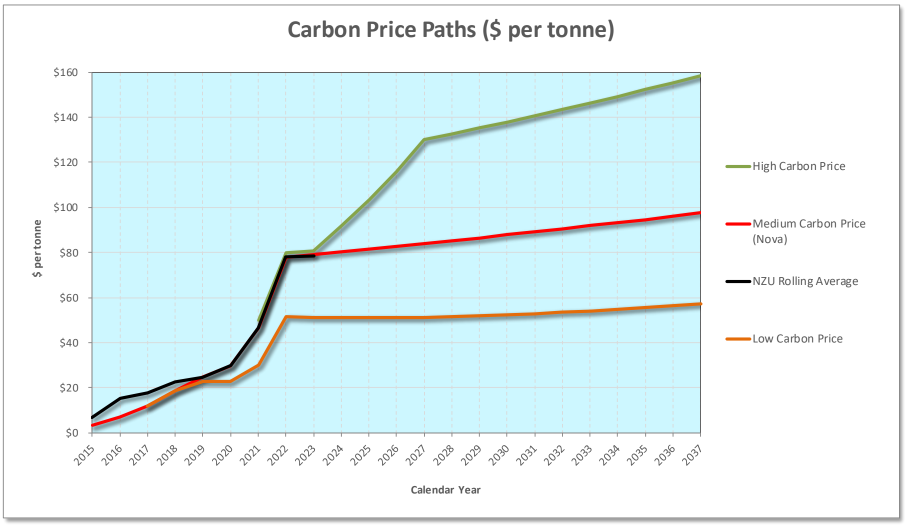
7 Price Impacts of Fuelling the Rankine units

Drawing on the Jan-23 Base Case with Tiwai remaining, this was rerun assuming the Rankine units only burned gas, to the date upon which the Rankine units are assumed to be retired from the market, i.e. 2029. The relative economics of burning gas at the Rankine units and at other plant increasingly depends on carbon price assumptions, so we actually ran two additional versions of the Base Case with Tiwai, giving three base runs in total, each with a different carbon price path. We then reran each of these three scenarios with the Rankine units burning 100% gas.

For avoidance of doubt, the new runs did not include recalculation of the "build schedule" for each scenario, i.e. the type, timing, location and capacity of new generation. If carbon prices were indeed significantly higher than assumed in the Base Case, then a new build schedule would include more renewable generation built sooner, which would reduce thermal generation earlier relative to the Base Case.

The three carbon price paths are shown below in Figure 12. The Base Case from the Price Path uses the medium carbon price path. The low carbon price path is 66% of the medium carbon price path, and the high carbon price path is based on cost-containment trigger prices in the ETS through to 2027 then inflating the 2027 value each year thereafter.

Figure 12 – Carbon Price Paths



The other factor that mutes the price impact of the Rankine units burning only gas is that the gas price path is rising over time, whereas coal prices come back from their recent highs of over USD $300 per tonne, to USD $125 per tonne by the end of 2025[55]. This price is the pre-Ukraine war high, so it is possible it could go lower still, further muting any reductions in price due to gas-only operation; pre-Ukraine coal prices averaged USD $80 to $85 per tonne.

[55] Global coal prices have already come off the highs of 2022, as Europe weans itself off Russian coal and gas, so this process is well underway.

Table 8 summarises the results of the six runs, showing the change in the average spot price at Benmore (BEN) and Otahuhu (OTA) in each year. The results are shown averaged over 91 inflow scenarios, and the price differences are small, though individual inflow years will show different results. With the low carbon price path, the cost of the Rankine units running on coal is less than running other gas-fired generators, so the Rankine units actually run more in this scenario. With the higher carbon prices, the Rankine units run less even in the updated Base Case, which tends to reduce the price benefit of burning only gas at the Rankine units.

Table 8 – Price Changes at BEN and OTA if Gas Displaces Coal for Generation

Year ending March	Low carbon		Medium carbon		High carbon	
	BEN	OTA	BEN	OTA	BEN	OTA
2024	-$0.92	-$0.99	-$1.37	-$1.58	-$1.53	-$1.75
2025	-$0.39	-$0.44	-$0.82	-$0.93	-$1.22	-$1.33
2026	-$0.59	-$0.66	-$0.71	-$0.86	-$0.95	-$1.14
2027	$0.15	$0.16	-$0.18	-$0.25	-$0.62	-$0.78
2028	$0.57	$0.62	-$0.07	-$0.08	-$0.48	-$0.63
2029	$1.13	$1.31	-$0.47	-$0.54	-$1.58	-$1.84
2030	$1.21	$1.33	-$0.30	-$0.29	-$1.54	-$1.64
Average	**$0.17**	**$0.19**	**-$0.56**	**-$0.65**	**-$1.13**	**-$1.30**

Taking a longer-term view, burning coal at the Rankine units may have kept electricity prices lower than they would have been had the Rankine units burned only gas. The environmental benefits of eliminating coal burning at the Rankine units are obvious and substantial, but this price analysis illustrates the need to improve gas supplies, and preferably also to bring gas prices down (or at least stop them rising), to realise these benefits while keeping the lights on and the wheels turning.

8 Industrial Process Heat Conversion

When it comes to process heat in industry, there is not the same level of detail in the data available in the public domain, relative to electricity generation and fuel consumption in general. However, we can estimate the amount of coal-fired process heat in the North Is, which is where gas is available in large quantities, by reference to data collected by or for EECA.

The Regional Heat Demand Database[56] provides a breakdown by industry sector of coal consumption for the South Is only[57]. We can make estimates for the North Is by subtracting the South Is figures from figures obtained from New-Zealand-wide data in EECA's end-use database[58]. North Is industry has access to piped gas, which has led to lower coal consumption than in the South Is in the process heat category.

Most of the coal is burned in boilers, so to calculate the change in emissions from conversion to gas, we also need to account for any change in boiler efficiency, which can be problematic because efficiencies vary depending on a range of factors. According to research by the IEA[59], coal boilers can reach 85% efficiency and gas boilers 75%, so this reduction in efficiency is taken account of in the table above, which also uses emission factors of 90 kt CO_2 per PJ of coal and 53 kt CO_2 per PJ of gas.

If we assume all North Is coal consumption converted to gas, then the estimated emissions reduction is 180 kt per annum, as shown in Table 9.

[56] https://www.eeca.govt.nz/insights/data-tools/regional-heat-demand-database/
[57] North Is data will be included at some point.
[58] https://www.eeca.govt.nz/insights/data-tools/energy-end-use-database/
[59] IEA Energy Technology Systems Analysis Programme Technology Brief I01, May 2010.

Table 9 – North Is Industrial Estimates

2020 Data	PJ	Coal Kt CO_2	Gas Kt CO_3	Emission Difference
High temp heat >300°C	2.0	178	119	-59
Intermediate heat 100-300°C	8.3	751	501	-250
Low temp - space heating <100°C	6.6	592	395	-197
Low temp - water heating <100°C	3.8	341	228	-113
Unallocated	0.4	38	25	-13
New Zealand	21.1	1,899	1,268	-632
Less South Is	15.1	1,359	907	-452
North Is	6.0	540	361	-180

Some sectors are more likely to convert from coal to gas firing than others. For example, low temperature space and water heating can be converted to electricity using heat pumps. More realistically, the conversion is most likely in the high and intermediate heat categories, which make up 49% of the New Zealand total; as a first approximation, if this percentage is applied to the total possible reduction, then the North Is emissions reduction estimate falls to 90 kt per annum.