Potential demand for thermal generation in the transition to a renewables-based electricity system

Prepared for the Electricity Authority

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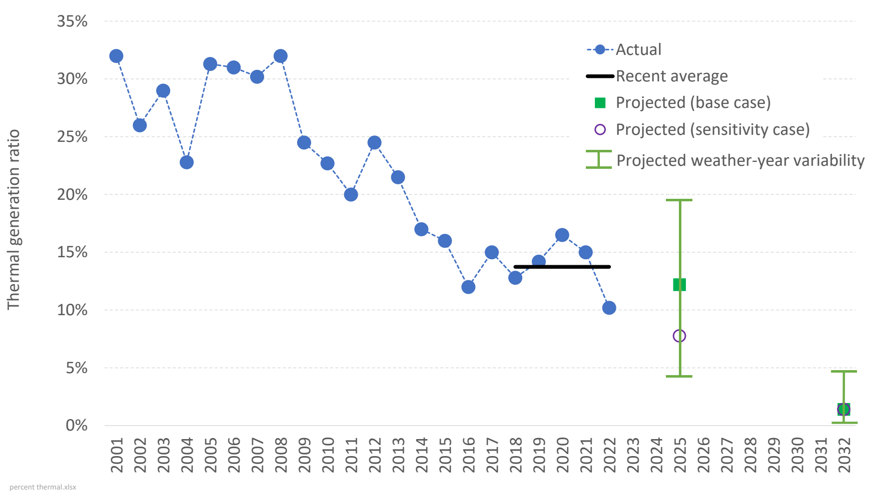
1 Executive Summary

1.1 Overall trends

The overall downward trend in demand for thermal generation is likely to continue over the coming decade, as thermal becomes increasingly confined to providing back-up services for a renewables-based electricity system. Whereas thermal generation averaged 14% of total supply in the last five years, by 2032 it will likely be around 1.5% of total supply on average as shown in Figure 1.

Figure 1: Percentage of thermal generation (base case)



Source: Concept analysis of public data. Cogen is excluded from calculation of ratio.

However, while average thermal generation is expected to decline, the demand for *flexible* thermal is expected to remain strong. This is reflected in the expected range for thermal demand across different 'weather years' (i.e. variability in hydro, wind and solar generation levels between years).

For example, while thermal generation in 2032 is projected to be around 1.5% on average, it could range between around 0.3% and 4.5% depending on the weather patterns in a particular year. These variations are shown by the green bars on the chart.

Turning to the nearer term outlook (to around 2025), our base case is for thermal generation demand to remain significant. This reflects an expectation that the pace of renewable development will take time to fully catch up with electricity demand, and that the Tiwai smelter will continue to operate post-2024. A further quickening of renewable development, lower than expected demand growth, or a reduction in Tiwai power usage would accelerate the thermal transition relative to the base case projection for 2025.

Under our base case for 2025, we project that all thermal units not already scheduled for closure will likely have a revenue earning opportunity sufficient to cover their estimated go-forward costs. However, thermal units (and especially the Rankine units) would have significant volatility in their net cashflows if reliant solely on spot market revenues due to the effect of weather variability (among other factors) on thermal demand and spot prices. Forward contracting could reduce that level of volatility.

By 2032, our base case projection indicates there is unlikely to be sufficient demand (and revenue) to support retention of all existing thermal units. By that date, retirement of some slower start capacity (either a CCGT or some Rankine units) appears likely to be efficient. However, demand for fast start back-up remains strong with continuing demand for service from all existing OCGTs.

1.2 No clear case for investment in new thermal generation

As regards the potential for investment in additional fast-start capacity to become economic, this appears unlikely in the base case. Rather, a mix of existing fast start and some slower starting thermal plant appears to be capable of meeting the demand for thermal generation to 2032 (at least) under base case assumptions.

The intuitive explanation for this result is that the flexibility available from existing peakers plus projected battery growth plus the existing hydro system is very substantial. This flexibility, in conjunction with the slower-start flexibility of Rankine or CCGT units (which have significant sunk costs) is a lower cost solution than investing in additional fast start thermal capacity.

1.3 Caveats and limitations

As with all forecasting exercises the analysis in this report is subject to uncertainty. Hence, it is important to consider both the base case results and sensitivity cases (see body of report).

It is also important to note that the assumptions underpinning the analysis are based on public information sources. It is possible there is relevant information known to thermal plant owners that is not reflected in our analysis, and which could affect the results.

Finally, the analysis focusses on implications for thermal *generation capacity*. The analysis does not consider the potential implications for fuel provision, such as in the upstream gas sector, as those matters are outside the scope of this report.

2 Introduction

2.1 Purpose

This report uses quantitative analysis to explore issues related to the transition to a renewables-based generation system. In particular it explores when and how the demand for thermal generation is likely to alter as the transition to a renewables-based system occurs.

2.2 Information sources

This report has been compiled based on Concept's analysis of information in the public domain.

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3 Overview of analytical questions and approach

3.1 Purpose

This section provides an overview of the analytical questions explored in this report, and the modelling tool used to explore those questions.

3.2 Key questions

The key questions explored in this report are:

- How and when is the demand for thermal generation likely to change in the transition to a renewables-based electricity system?
- How might different types of thermal generation be affected?

3.3 Thermal generation demand is a residual demand

Traditionally, thermal generation has filled two roles:

- Baseload supply. This is when plant operates at maximum output most of the time, and primarily provides energy to the system.
- Peaking or firming supply. This role is when the plant operates intermittently to respond to changes in demand or changes in generation from other sources.

Increased carbon and fuel costs, combined with reduced costs for renewable generation have made thermal baseload uneconomic. This means that demand for thermal generation is essentially a residual demand, providing back-up to the system when other resources are not available or are more costly.

In practice, this means that thermal generation demand is determined by:

a. trends in total electricity demand and the rate at which new renewable supply is developed

- the cost and availability of alternative forms of back-up such as batteries, demand response, or economic overbuild of renewables[1]
- the influence of weather variability on renewable generation levels in any given year
- random outages that affect electricity consuming or generation plant.

Our analysis seeks to take account of these various factors. It builds on earlier work undertaken by the Climate Change Commission, Interim Climate Change Commission, and Transpower.

3.4 Cogeneration plant

Our analysis focusses on the future demand for generation from the larger thermal units.[2] We have not undertaken equivalent analysis for cogeneration plant even though this plant exports some electricity onto the grid. This is because:

- The bulk of electricity exported onto the grid comes from the larger thermal generation units included in our analysis, rather than cogeneration plant.
- Retirement/retention decisions for cogen units are likely to be driven strongly by the host industrial site's need for process heat, and the relative costs of different options. Electricity sale revenues are unlikely to be the dominant factor affecting retention/retirement decisions for cogens, unlike the case for the larger electricity generation units.

Having made these observations, our view is that the exclusion of cogeneration from the detailed modelling is unlikely to affect the conclusions in this report.

3.5 How the modelling tool works

The analysis in this report has been compiled based on the output of Concept's ORC electricity system model. This model simulates the operation of the electricity system, given certain assumptions about the level and pattern of future demand, and the resources (generation, batteries, demand response etc) available to satisfy projected demand.

The modelling tool uses a chronological approach with a one-hour timestep. The chronological approach allows temporal issues to be accounted for in some detail, unlike modelling approaches which use stylised time blocks (such as weekday peak, weekend off-peak etc).

ORC also models thermal plant operation in some detail, including allowing for gas costs to change with prevailing system conditions[3], variation in start-up costs for different plant, and slow start restrictions for some plant. These are critical issues for the modelling of thermal generation demand in the transition to a renewables-based system.

[1] This refers to the philosophy where renewable generation is built to reflect cost trade-offs for society, rather than an expectation that it will be configured to maximise energy production per se, i.e. it may be economic to spill some generation at times. This philosophy has applied within the hydro system for many decades, where the capacity of installed turbines in a station has been sized to reflect economic trade-offs rather than capture all available hydro inflows. This means that some energy is spilled when water flows (occasionally) exceed the generation capacity of the station.

[2] In particular, the combined-cycle and Rankine units at the Huntly site, and the ten open-cycle units at various locations.

[3] For example, gas costs are higher when gas in storage is running low and vice versa.

3.5.1 'Weather years'

ORC repeats the modelling of each future reference year[4] under different weather conditions based on 40 historical 'weather years'. These use historical values for the key drivers of variable renewable generation: hydro inflows, wind, and sunshine. This is another critical issue for modelling demand for thermal generation in the transition to a renewables-based system.

3.5.2 Instantaneous reserves and transmission system

ORC models the demand for thermal generation taking account of the need to meet energy demand and to provide reserves cover.

To ensure workable computational timeframes, ORC has a simplified representation of the transmission system. It is a two-node model (one node in each island), with transmission constraints and reserve requirements modelled for the HVDC. This simplified approach for representing transmission issues is not expected to materially affect the conclusions from the analysis because all of the thermal generation is located in the North Island and is relatively close to major demand centres.

3.5.3 Simulation and optimisation modes

ORC can be run in two different modes. In the simulation mode, all demand and generation fleet assumptions are inputs, and the state of system balance is an *output*. This is a useful mode for dealing with timeframes of a few years, when there is reasonable information about what demand and generation will be on the system (or at least the number of possible scenarios is limited). Importantly, in this mode the system can be tight, or have a supply overhang, depending on the particular profile of new generation build/retirements and demand that is assumed.

The alternative optimisation mode allows the model to determine the mix of generation/batteries/demand response that will be built/utilised from a pre-defined menu of option.

It this mode the model will 'plant' the mix of resources (existing and new build) that will serve total demand and achieve lowest overall cost.[5] In this mode the state of the system balance is effectively an input (the model seeks an optimal balanced outcome unless a different outcome is specified), and the model is used to identify the resulting planting schedule as an *output*. The planting schedule will show the utilisation of existing (and any new) resources on the system.

This type of optimisation mode is a commonly used approach by modellers in New Zealand for longer term modelling (say beyond 3-5 years). This is because the system has exhibited a tendency to revert to a relatively balanced state over time.

The optimisation mode entails running the model for many different possible planting configurations to determine the preferred mix of resources on the system. It is therefore much more computationally intensive that the simulation mode.

3.6 Reference years

Our analysis focussed on two timeframes or reference years. The earlier reference year (2025) was chosen to assess how quickly the demand for thermal generation is changing in the next few years. This helps to gauge

[4] See section 3.6 for an explanation of reference years.

[5] Strictly speaking the model only builds resources if they are revenue adequate. A cross check is performed to ensure the resulting generation build mix achieves a minimisation of total system costs, where system cost is the sum of incremental build and operating costs and the cost of demand response.

the degree to which retirement/retention decisions may be imminent based on underlying system fundamentals.

The second reference year was chosen to be some distance into the future, when the system is likely to have completed much of the thermal transition. The 2032 year was used to represent this point given that it is decade away.

3.7 Base case and sensitivity cases

Our central assumption sets for 2025 and 2032 reflected in base cases for those years. Information on the assumptions is set out in Appendix A:

Two key areas of uncertainty for 2025 are the level of overall demand and development of new renewables (among other parameters). Both of these are changing as the economy decarbonises.

As a cross-check on the base case demand and renewable supply assumptions for 2025, we compared average spot prices that are generated by ORC in the base case with prevailing forward contract prices for 2025. These were closely aligned.

Having said that, we acknowledge there is uncertainty about both demand and renewable development trends in the period to 2025. For this reason we also considered sensitivity cases that reflect:

a. A further acceleration in renewable development beyond projects that have been committed for the next 24 months.
b. A closure of the Tiwai smelter after the current supply contract ends in 2024.

We also considered a sensitivity case for 2025 in which spot prices in dry years are constrained below efficient levels.

In relation to 2032, our base case assumption is that renewable development will come into balance with demand (including further growth in demand as the economy electrifies).

The base case for 2032 does not assume the development of any large-scale new sources of flexibility (such as a flexible smelter, hydrogen production, or pumped hydro storage).

The analysis for 2032 also considers a sensitivity case where the Tiwai smelter operates on a flexible basis.

3.8 Climate-related policy assumptions

In terms of climate-related policy assumptions, we have been guided by the Government's Emission Reduction Plan released in May 2022.[6] The plan contains a formal target to have 50% of all final consumer energy coming from renewable sources by 2035.

The plan does not contain a formal target for the share of electricity generation coming from renewable sources. Rather, it indicated the Government continues to support its aspirational target of 100 per cent renewable electricity by 2030, and that the target would be reviewed in 2024.

[6] See https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf.

3.9 Limitations and qualifications of analysis

As with all forecasting exercises the analysis in this report is subject to uncertainty. Hence, it is important to consider both the base case results and sensitivity cases.

It is also important to note that the analysis is based on public information sources. This is especially important in relation to our analysis of stay-in-business costs, start-up costs and operating restrictions for the slower-starting units. It is possible there is relevant information known to thermal plant owners that is not reflected in our analysis that could affect the results.

Another key point to note is that the analysis focusses on implications for thermal *generation capacity*. The analysis does not consider the potential implications for fuel provision. For example, it does not explore the extent of benefits from investment in gas production or underground gas storage capacity. Such matters are outside the scope of the analysis.

Finally, the analysis incorporates the effects of short-term random plant outages on the efficient plant mix but assumes that none of the existing thermal plants suffers a major failure that renders it permanently inoperable.

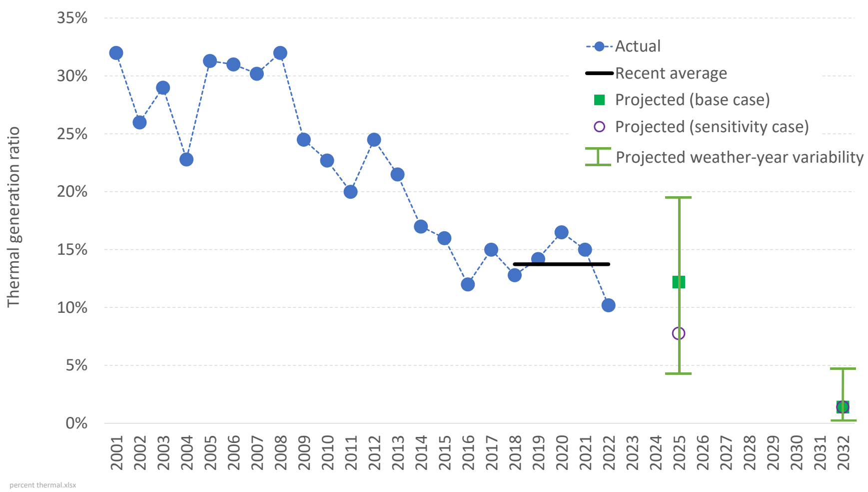
4 Projected demand for thermal generation

This section sets out the results of analysis on the demand for thermal generation services over the coming decade.

4.1 Steep downward trend projected for average thermal generation

Figure 2 shows the actual thermal generation percentage in recent years and projections for the two future reference years.

Figure 2: Percentage of thermal generation (base case)



Source: Concept analysis of public data. Cogen is excluded from calculation of ratio.

As shown in Figure 2, the thermal share has declined from around 32% in 2001 to an average of approximately 14% in the last five years. There were year-to-year fluctuations around the downward trend, largely due to variation in annual hydro inflows. For example, 2022 had relatively high inflows resulting in a thermal percentage close to 10%.

The chart also shows the projected thermal ratio (green boxes) under our base case assumptions for the two reference years. For the 2025 year the thermal percentage is projected to average around 12%. For the 2032 year the thermal percentage is projected to fall to an average of around 1.5%. The chart also shows the projected results (hollow circles) for sensitivity cases discussed later in this section.

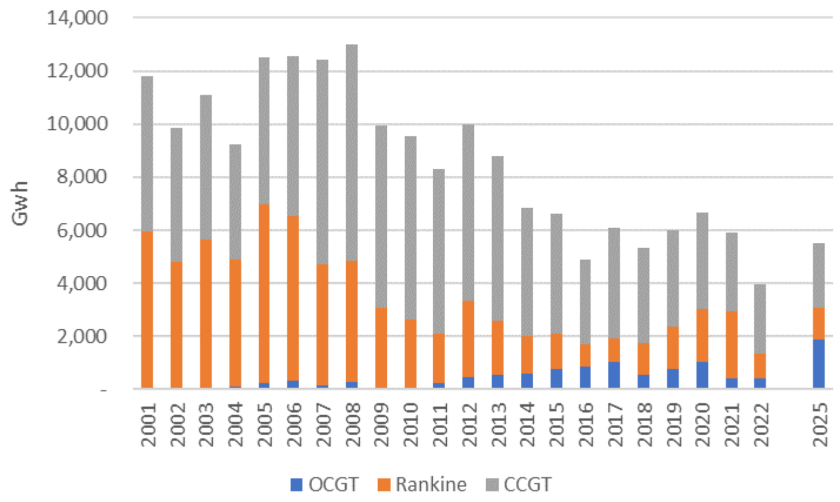
It is important to note that all of the projections for 2025 and 2032 are the modelled mean thermal percentage across many weather years. Depending on hydro inflows and other renewable generation, the percentage can vary. For example the base case projections vary from approximately 4% to 20% in 2025, and from 0.3% to 4.5% in 2032. These variations are shown by the green bars.

4.2 Solid near-term thermal demand in base case (2025)

Figure 3 shows projected thermal demand in the base case for 2025 expressed in GWh terms and by plant type. Again, it is important to note the projected level for 2025 is an average over all weather years, whereas the historical levels reflect the actual weather in each particular year.

The projected demand for thermal generation in the base case for 2025 is slightly lower than levels observed in 2019-2021, but above the levels observed in 2018 and 2022 (both of which were 'wet-years'). The composition of thermal output is projected to change, with more from OCGT peakers and less from the slower starting CCGT and Rankine units. However, despite the shift in the duty between units, significant demand is projected for all thermal generation types.

Figure 3: Historical and projected GWh – base case 2025



Source: Concept analysis of public data.

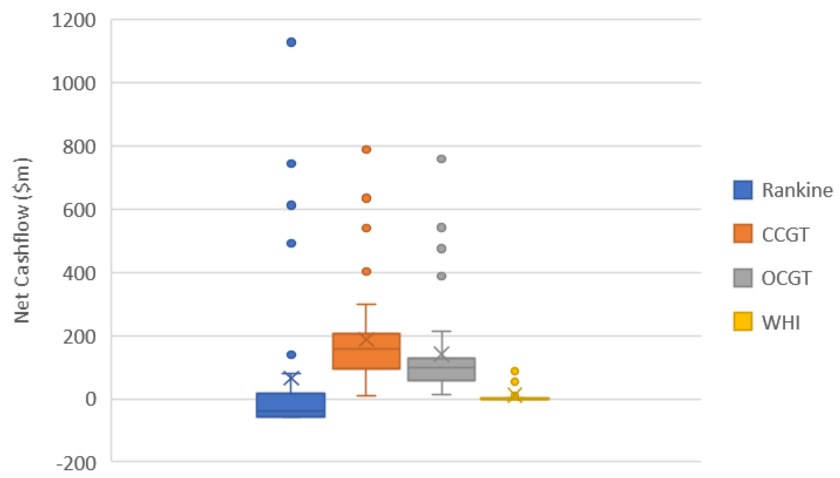
4.3 Net cashflows for thermal units in base case (2025)

We have estimated the annual revenues for Rankine, CCGT, OCGT and diesel fired units in 2025 assuming operators are reliant solely on the spot market for revenues. That revenue data was combined with estimates of go-forward costs[7] for the units based on public sources to calculate net cashflows.

These net cashflow figures take account of items such as carbon and fuel costs, variable operating costs and annualised stay-in-business capital costs.

We expect go-forward net cashflows to be a key measure for thermal operators facing retention or retirement decisions. If a unit is not expected to generate positive expected net cashflow into the future, it seems unlikely it would remain in service, all other things being equal.

Figure 4: Net cashflows by thermal plant type – base case 2025



Source: Concept analysis of public data.

[7] Go-forward costs are the costs to remain available and to operate plant to generate electricity. It includes fuel, carbon charges, variable operating costs, and fixed operating costs including periodic major plant overhauls and recertifications.

However, it is also important to note that the net cashflow measure excludes any allowance for a return on pre-existing capital investment. Although such capital costs are sunk (and therefore not strictly relevant for future decisions), thermal owners may be unwilling to retain a plant in service without at least some return on sunk investment. For this reason the results may understate the likelihood of retirement. The results need to be interpreted with this in mind.

Figure 3 presents the cashflow analysis as a box and whisker graph. The mean net cashflow (averaged over all weather years) is shown by the X for each of the different types of thermal unit. The inter-quartile range is shown by the shaded box, and the whiskers indicate the range within which most values lie. The individual dots represent observations well outside the rest of the distribution.[8]

Key observations from the chart are:

a. Mean measures of net cashflow are positive for all generation types, but there is significant variation in net cashflows across weather years.
b. For CCGTs and OCGTs (including Whirinaki) the expected net cashflow range is positive across all weather years (indicated by the bottom whisker being above zero).
c. For the three Rankine units (shown by the blue bar) the mean expectation is for positive net cashflow, but due to appreciable stay in business costs and a running cost that is higher than the gas fired units, the Rankine units would have negative net cashflows in many years if they were solely reliant on spot market sales for their revenue. Indeed, the median (shown by the middle line in the bar on the chart) is also negative, indicating that in the majority of years the Rankine units would have negative net cashflows if reliant solely on spot market sales for their revenue. On the other hand, the highest net cashflow outcomes on the chart are for the Rankine units. The units are projected to make substantial net positive cashflows in extreme dry-years due to their large generation capacity and ability to generate for long periods if required. Having said that, it is important to note that the probability of any given year being extremely dry is relatively low.

Overall, the results suggest that under the base case assumptions, thermal units that have not already been scheduled for closure[9] should have a revenue earning opportunity sufficient to cover their go forward costs in 2025. However, the thermal units (and especially the Rankine units) would have significant volatility in their net cashflows from spot market revenues due to weather variability. Thermal operators who are risk averse would likely seek to reduce that cashflow volatility via forward contracting for some of their revenue.

4.4 Sensitivity cases for 2025

We considered two types of sensitivity cases for 2025.

For the first, as noted in section 3.7, there is some uncertainty about the growth in electricity demand and renewable development that will take place by 2025.

To test how sensitive the base case outcomes are to alternative assumptions, we modelled a case with faster build of new renewable generation (the build schedule for the base case is largely based on

[8] These values are included for the purposes of calculating the mean, median and quartiles.

[9] All units except TCC and Te Rapa which are scheduled for retirement before 2025.

committed projects). We also modelled the system were Tiwai to exit after 2024.

For the second type of sensitivity, we considered the effect if spot prices were not able to rise in dry years to the level assumed in the analysis. This scenario is designed to test the effect if spot prices in dry years are constrained well below levels that are efficient.

4.4.1 Sensitivity cases for 2025 of a system under less strain

This faster renewable build scenario assumed that an additional 2,000 GWh of solar would be available by 2025, relative to the base case. While this could be viewed as aggressive, we note that grid-scale solar projects have been built rapidly in Australia (less than a year in at least one case), and there are many projects reported to be in the pipeline.

Having said that, we stress that this sensitivity is not our central case. In particular, we note that the average annual spot price implied by this case is materially lower than the prevailing forward contract price for 2025.

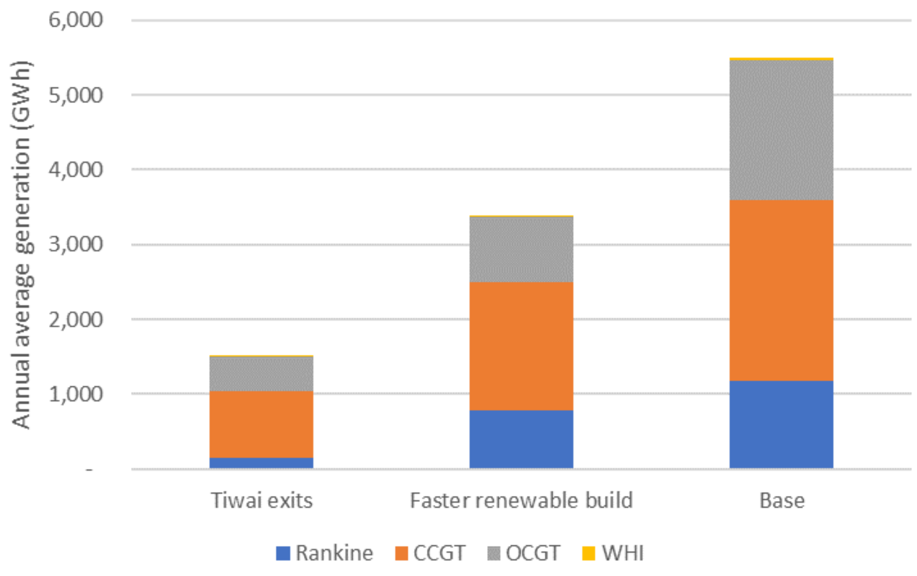
Another uncertainty that is relevant for 2025 relates to the Tiwai smelter. The base case assumes the smelter will continue in operation beyond the expiry of the current supply contract in December 2024. We also analysed a sensitivity case in which the smelter does not operate from 2025. Again, the average annual spot price implied by this case was materially lower than the prevailing forward price for 2025.

4.4.1.1 Effect on demand for thermal generation

Figure 5 shows the projected demand for thermal generation in 2025 in the sensitivity cases for 2025. Both sensitivity cases show materially lower thermal demand than in the base case.

For the faster renewable build case, the additional renewable output displaces thermal demand on a one-for-one basis. In the Tiwai exit case, the reduction in thermal generation demand (around 4,000 GWh) is less than the decline in total power demand. This is because a smelter closure in 2025 would free up renewable generation in the South Island, but some of that freed generation is expected to be trapped in the island due to transmission constraints on the HVDC link.

Figure 5: Sensitivity cases and base case 2025



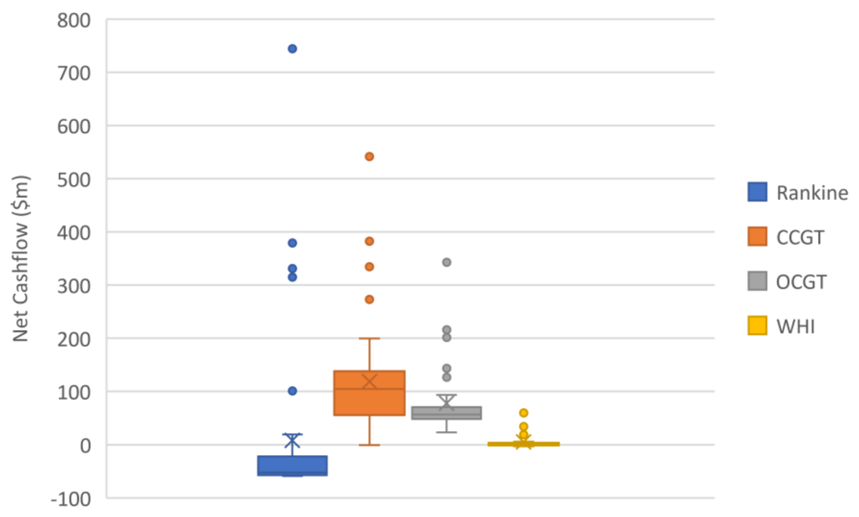
Source: Concept analysis of public data.

4.4.1.2 Effect on cashflows for thermal units

Figure 6 shows the projected net cashflows for different plant types in 2025 in the faster renewable build scenario. Despite the overall reduction in the demand for thermal generation compared to past levels, the analysis indicates that OCGTs would remain revenue adequate. This reflects the flexible nature of the plant.

However, there is less demand for output from slower-starting plant. In particular, the sensitivity case shows a large decrease in demand for slower-starting thermal, with three Rankine units barely breaking even. Our analysis suggests that total system costs would be marginally lower with only two Rankine units likely to be economic in this scenario. This suggests the third Rankine unit could be retired (or mothballed) in this scenario.

Figure 6: Net cashflows - faster renewable build case 2025

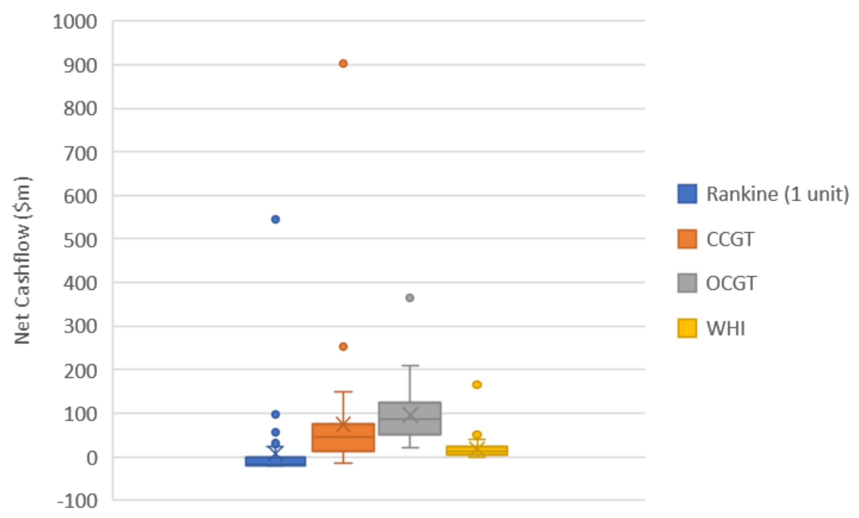


Source: Concept analysis of public data.

Figure 7 shows the projected net cashflows for different plant types in 2025 in the Tiwai closure scenario. The analysis indicates that OCGTs would remain revenue adequate. Again, this reflects the relatively flexible nature of this plant.

However, there is less demand for slower-start thermal operation. Under the assumptions in this case, it appears likely that two Rankine units would be retired or mothballed.[10]

Figure 7: Net cashflows – Tiwai closure case 2025



Source: Concept analysis of public data.

[10] However, see the caveats discussed in section 4.4.2 in relation to the relative economics of retaining Rankine or CCGT units. Those same considerations would be relevant in 2025. Another point to note is that we have assumed Rankine costs are largely driven by the number of frontline units available for service. There are likely to be some costs which are *station-based* rather than *unit-based.*

4.4.2 Sensitivity cases for 2025 – lower spot prices in dry years

In this sensitivity we excluded revenues from the driest 10% of years (1992, 2001, 2008, 2012).[11] This has the effect of assuming that prices in these years will be similar to those in other years.

Figure 8 - Net cashflows – lower prices in dry years 2025

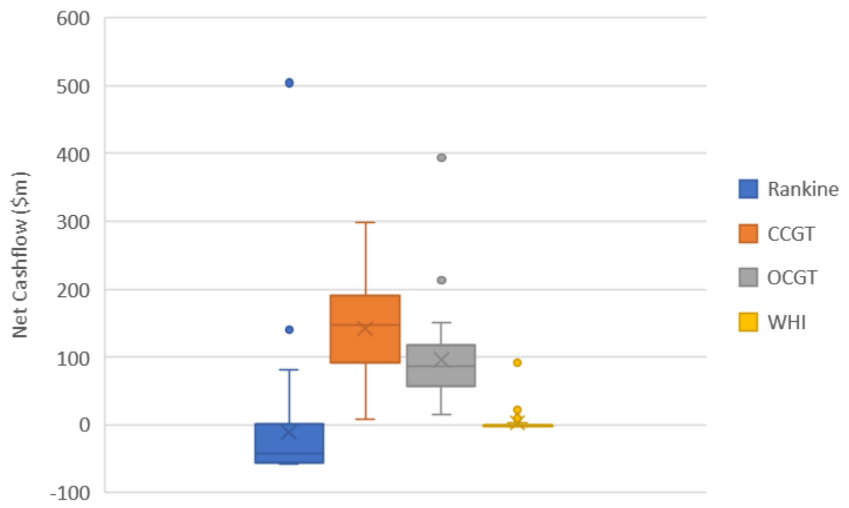


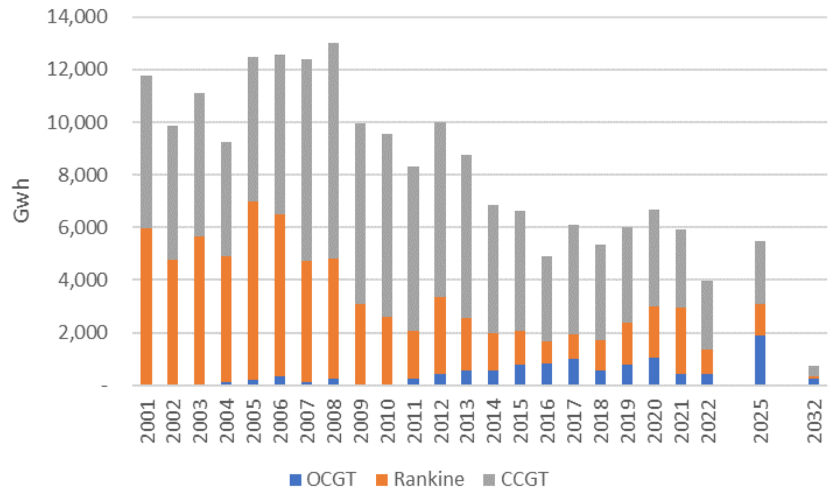
Figure 8 shows that mean expected cashflows for all thermal units is lower than the base case and becomes negative for the Rankine units in this sensitivity.

Note that our assumption that average spot prices in the driest years will be similar to other years is somewhat unrealistic. Spot prices will almost certainly be higher than average. However, this sensitivity shows the importance of dry years on the economics of thermal plant operation, especially for the slower-start units.

4.5 More nuanced picture for thermal by 2032

Figure 9 shows the projected demand for thermal generation in the base case for 2032. By that time the renewable generation base in New Zealand is expected to have expanded significantly. As a result, thermal generation levels are expected to be markedly lower than in the past (or 2025).

Figure 9: Historical and projected GWh – base case 2032



Source: Concept analysis of public data.

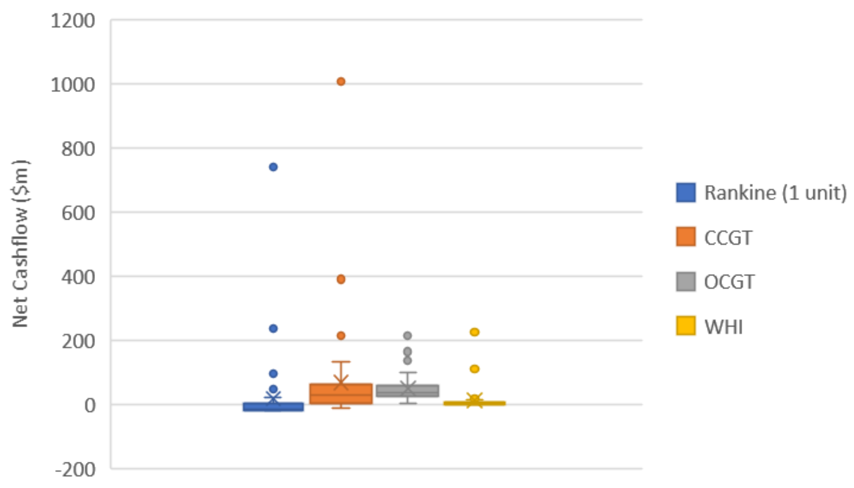
Figure 10 shows the estimated net cashflows for different plant types in 2032. Despite the very substantial reduction in the demand for thermal

[11] These are not necessarily the years with the lowest total inflows, but rather years with sustained periods of low inflows.

generation, the analysis indicates that OCGTs would remain revenue adequate under the base case assumptions.

This reflects the flexible nature of the plant and its ability to provide a service that is expected to become increasingly valuable over time. In particular a growing share of supply from intermittent renewable sources is expected to lift the value of short-term flexibility services, which partially offsets the loss of thermal generation volumes.

Figure 10: Net cashflows by thermal plant type – base case 2032



Source: Concept analysis of public data.

The position for slower starting plant is more nuanced. By 2032 there remains some demand for slower-starting plant, but not for all of the currently existing units.

Under the base case assumptions for 2032 the analysis indicates a CCGT would be revenue adequate and one of currently three Rankine units (the blue bar is for one Rankine unit). The net cashflow position for the remaining two Rankine units (not shown on the chart) would be negative on a *mean* basis.

However, it is important to note that the efficient mix of slower starting plant is quite sensitive to the cost of gas relative to fuel for Rankine units (whether coal or biomass).

It is possible that the Rankine units might be more cost efficient than the CCGT in some scenarios. For example, in a scenario where the cost of flexible gas is higher than assumed in the base case. In that situation, the economics could favour retention of Rankine units versus CCGT capacity.

In either case, by 2032 it appears unlikely that there would be an economic need (and sufficient market revenues) to support retention of the CCGT and all three Rankine units.

4.5.1 Sensitivity case with flexible smelter 2032

We considered a sensitivity case for 2032 with a sizeable additional flexibility source in the South Island, such as a smelter with flexible demand.[12]

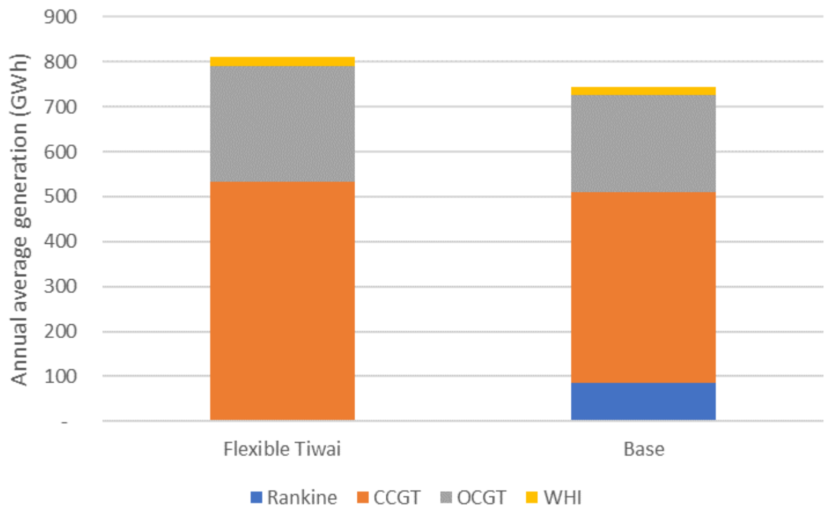
Figure 11 shows the projected level of thermal generation demand in the flexible smelter case compared to the base case for 2032. It indicates the

[12] A large South Island pumped storage facility would be likely to have a broadly similar effect on thermal demand/net revenues but has not been explicitly modelled.

overall level of demand for thermal generation is quite similar in the two cases.[13]

However, the composition of demand differs between the cases, with no demand for Rankine unit output in the flexible smelter case.[14]

Figure 11: Thermal demand - sensitivity case flexible smelter 2032

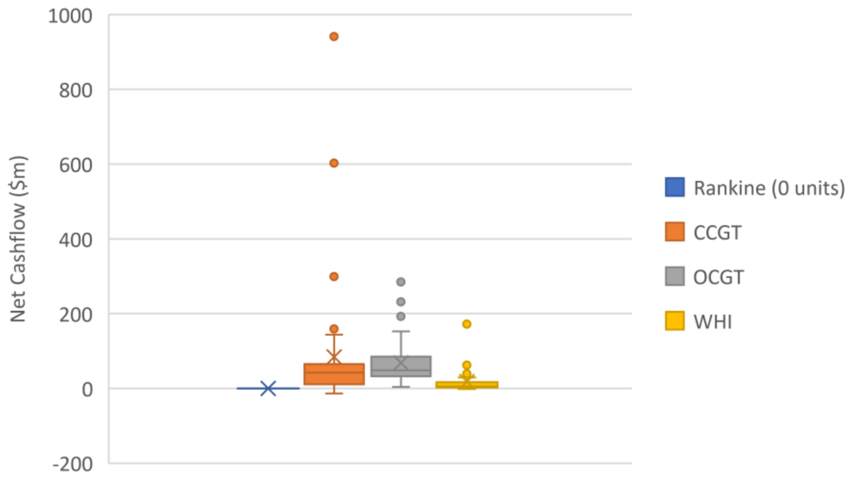


Source: Concept analysis of public data.

Figure 12 shows the projected impact on net cashflows for different plant types in flexible smelter sensitivity case in 2032. Relative to the base case for 2032, the key change is much lower demand for slower start thermal services. That is the reason there is no cashflow projected for with the Rankine units.

As with the base case for 2032, it is possible that slower start services could be provided from the Rankine units rather than the CCGT unit (depending on relative fuel costs among other things). In addition, the estimated net cashflows for the fast start peaker units remain positive in this sensitivity case.

Figure 12: Net cashflows – sensitivity case flexible smelter 2032



Source: Concept analysis of public data.

[13] Eagle-eyed readers may notice that estimated thermal generation demand is around 50 GWh *higher* in the flexible smelter case than in the base case for 2032. We consider this difference to be within the margin of error for the analysis. For example, it equates to around 0.1% of total system demand for electricity in 2032.

[14] Again, the caveat in relation to the economics of the Rankine units versus CCGT capacity applies.

4.6 No clear case for investment in new thermal generation

We considered the question of whether investment in new thermal plant might be beneficial from an efficiency perspective (and be revenue adequate for an operator) in 2032. In particular, we examined whether investment in new flexible OCGT capacity might be desirable to substitute for, or complement, slower starting thermal units.

Our analysis did not identify a scenario where investment in new thermal generation was likely to be economically beneficial (or revenue adequate) in or before 2032. Instead, it appears that a mix of the existing flexible OCGTs plus some slower start plant (CCGT and/or some Rankine units) plus storage batteries would be the most efficient solution to provide back-up services.

The intuitive explanation for this result is that the flexibility available from existing peakers plus projected battery growth plus the existing hydro system is very substantial. This flexibility, in conjunction with the slower-start flexibility of Rankine or CCGT units (which have significant sunk costs) is a lower cost solution than additional thermal capacity (which requires significant upfront capital expenditure).

This observation is potentially quite significant because some market commentary has suggested that investment in new flexible thermal plant might be desirable this decade.

Having made this observation, we should emphasise some caveats. First, the assumptions for stay-in-business costs, start-up costs and operating restrictions for all units are based on publicly available information. It is possible there is other relevant information known to thermal plant owners that is not reflected in the analysis. For example, if slower start thermal were less flexible than modelled, then more investment in new more responsive plant might be efficient.

Second, the analysis focusses on potential investment in new thermal *generation* capacity. The analysis does not consider the potential for investment to be desirable in relation to *fuel provision*, for example investment in gas production or underground gas storage capacity. Such matters are outside the scope of the analysis.

Finally, the analysis incorporates the effects of short-term random plant outages on the efficient plant mix but assumes that none of the existing thermal plants suffers a major failure that renders it permanently inoperable. Were such an event to occur, that could alter the economic benefit equation for investment in flexible new thermal plant.

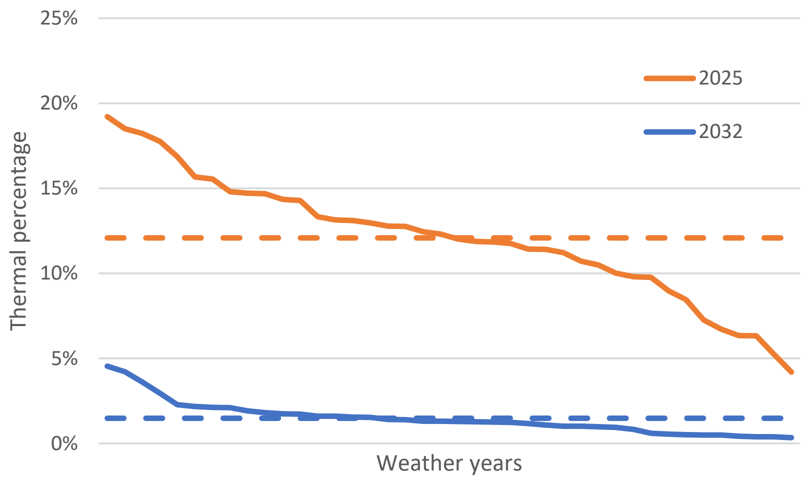
4.7 Effect of weather variation on thermal demand

As noted above, actual thermal generation levels in 2025 and 2032 will be strongly influenced by the prevailing weather in those years (in addition to system level changes in demand and renewable supply).

That weather dependency is not surprising given the role of thermal generation as a provider of back-up services. A more nuanced change centres on what that weather dependency is likely to mean for the nature of thermal operation over time.

This more subtle effect is illustrated by Figure 13 which depicts projected thermal generation percentages ranked by weather years.

Figure 13: Thermal ratios across 'weather years'



Source: Concept analysis

Broadly speaking dry-years are toward the lefthand side of the chart and vice versa. The chart shows two separate lines for the 2025 and 2032 reference years respectively. Key observations from the chart include:

a. The line for 2025 is much steeper than for 2032. This reflects the expectation that thermal generation will provide a mix of short-term peaking and hydro-firming in 2025. Hence, thermal generation is much lower than average in relatively wet years and vice versa.
b. However, by 2032 the level of thermal generation is expected to be very low across most weather years. Put another way, the difference in thermal generation between moderately wet years and wet-years is small because thermal generation as a whole is low. Hence there is little scope to turn down thermal in a wet-year. Instead, a sizeable proportion of the downward flex in total generation in this analysis comes from less than full utilisation of wind/solar or hydro in wet-years (i.e. spill). Conversely, while thermal generation in 2032 does not reduce much in wet years, it does increase appreciably in very dry years. This is shown by the slope of the lines for 2025 and 2032 being quite similar on the far left-hand side of the chart.
c. Even in very wet years there is still a demand for thermal to provide short-term peaking services in 2032. This is shown by thermal generation demand remaining above zero even in the wettest years.

Appendix A: Generic assumptions

All dollars are real $2022.

FOM = fixed operating and maintenance costs, VOM=variable operating and maintenance costs

Base case	2025	2032	Comment
Gross demand TWh	45.5	50	Estimates – includes 5TWh for Tiwai smelter
HVDC capacity MW North	1200	1200	Estimates based on observed transfers
HVDC capacity MW South	1000	1000	See above
New build costs			
New wind capital cost recovery $/kW/yr	N/A	146	Estimates based on recent industry reports
New solar capital cost recovery $/kW/yr	N/A	110	See above
New OCGT capital cost recovery $/kW/yr	N/A	125	See above (includes FOM)
Battery storage capital cost recovery $/kW/yr	N/A	122	See above – for 4 hour batteries
Existing plant costs			
OCGT VOM $/MWh	10	10	Estimates based on industry reports and analysis of company disclosures
OCGT FOM $/kW/yr	20	20	See above
CCGT VOM $/MWh	5	5	See above
CCGT FOM $/kW/yr	40	40	See above
Rankine VOM $/MWh	20	20	See above
Rankine FOM $/kW/yr	80	80	See above
Other			
Electricity demand response (tranche size)	2.5% of demand	2.5% of demand	Four tranches. Final tranche includes all remaining demand.
Electricity demand response (tranche cost) $/MWh	700/3k/10k/20k	700/3k/10k/20k	Estimates
Carbon costs $/t	100	150	Estimates
Gas costs (long run for investment decisions) $/GJ	8.3 (7 for commodity plus cost of swing)	13.1 (7 for commodity plus cost of swing)	Commodity cost is for notional base load demand. Cost of swing (flexibility) is calculated in model. Figures are an average across thermal fleet.
Gas costs (short run for dispatch decisions) $/GJ	3.5 to 25	3.5 to 25	Gas costs are dynamic depending on level of gas storage and whether gas demand response is called upon.
Gas demand response	Up to 30 TJ/day @ 25 $/GJ	Up to 30 TJ/day @ 25 $/GJ	Estimate
Gas storage working volume PJ	~5PJ	~5PJ	Assumes continued derating of Ahuroa underground gas storage capacity
Coal costs $/GJ	7	7	Estimate inclusive of transport and other handling costs
Biofuel costs $/GJ	N.A.	Equivalent to coal plus carbon	Estimate based on industry reports

Appendix B: Overview of thermal plant

Table 1 shows the thermal generation units in New Zealand[15] at the time of writing.

Table 1: Existing thermal generators in New Zealand

Thermal unit	Fuel	Operator	Capacity (MW)	Built	Comment
Open cycle gas turbines (OCGTs)					
Junction Road	Gas	Nova	2x50	2020	Fast starting
McKee	Gas	Nova	2x50	2013	Fast starting
Stratford	Gas	Contact	2x105	2010	Fast starting
Whirinaki	Diesel	Contact	3x52	2004	Fast starting
Huntly 6	Gas	Genesis	51	2004	Fast starting
Sub-total OCGT			617		
Combined cycle gas turbines (CCGTs) and Rankine cycle (RC) units					
Huntly 5 (CCGT)	Gas	Genesis	403	2007	Slower starting
TCC (CCGT)	Gas/coal	Contact	377	1998	Slower starting
Huntly 1,2,4 (RC)	Gas	Genesis	3x250	1983	Slower starting
Sub-total			1,530		
Total			2,147		

Source: Company data

We discuss each station below, including information related to their capacity, function, resource consents, and expected life.

4.8 Huntly power station units

The Huntly Power Station is owned by Genesis Energy and is New Zealand's largest power station. It is located in Waikato, relatively close to the Auckland load centre.

Huntly consists of three Rankine units, an OCGT unit and a high-efficiency combined cycle gas turbine (CCGT) unit.

The Huntly site has eight key consents from the Waikato Regional Council that allow it to continue operations until 2037.[16] The consent envelope allows for the Rankine units to be replaced by up to 400 MW of OCGT units.

4.8.1 Units 1, 3 and 4 (Rankine units)

Huntly originally commissioned four Rankine units in the early 1980s, although Unit 2 is now just retained as a backup and Unit 3 was decommissioned in 2012. The units use either gas or coal to create steam in a boiler which in turn generates electricity. The steam is cooled primarily using water from the Waikato River. Resource consent conditions restrict use of Rankine units on hot days by preventing discharge of this water back to the river when the river temperature exceeds a particular level. However, a 'helper' cooling tower unit allows one Rankine unit to operate at about 150 MW without using the Waikato River for cooling purposes.

Each unit has a capacity of around 250 MW. While the design life of Rankine units was expected to be about 25 years, Genesis reported that an independent assessment in 2021 determined that the "current operational

[15] Defined as 10 MW or more and excluding cogeneration stations.

[16] See PowerPoint Presentation (waikatoregion.govt.nz)

performance can be maintained to 2030 and could be extended to at least 2040.” [17]

It is expected that the Rankine units will be available until they are no longer economic to operate. While Genesis’ consents allow them to be replaced with OCGT units, the Rankine units have the advantage of being able to operate on multiple fuel sources. The ability to store fuel also makes the Rankine units a potential alternative to the Lake Onslow pumped storage proposal.[18]

Genesis has stated that it intends to only use coal in abnormal market conditions and phase it out completely by 2030.[19] Genesis has trialled the use of biomass fuel in Rankine units. The total variable cost of running on biomass is not yet known but Genesis has indicated it may be similar to coal depending on the level of carbon charges.[20]

4.8.2 Unit 5 (CCGT)

Huntly Unit 5 was previously known as E3P (Energy Efficiency Enhancement Project) and was commissioned in 2007. It uses a CCGT unit, a heat recovery steam generator and a steam turbine to generate electricity. It is cooled using a cooling tower, so does not use water from the Waikato River.

Usually Unit 5 has a capacity of 385 MW, but in colder weather it can generate up to 403 MW. The design life of Unit 5 was expected to be approximately 30 years, although with refurbishment the unit life could be extended. On the other hand running the unit in a more flexible mode is likely to shorten the unit life (mostly based on number of cold starts).

4.8.3 Unit 6 (OCGT)

Huntly Unit 6 was previously known as P40 and was commissioned in 2004. It uses an OCGT unit fuelled by either natural gas or diesel.

It has a normal rated capacity of 48 MW but can produce up to 50.8 MW and is used to provide electricity to the grid during periods of peak demand. The design life of Unit 6 was expected to be approximately 25 years, although with refurbishment the unit life could be extended to about 40 years.

4.8.4 Junction Road (OCGT)

The Junction Road plant is owned by Nova Energy. It was commissioned in 2020 and is located in Taranaki south of New Plymouth. The plant uses two OCGT units fuelled by natural gas to provide energy to the grid during periods of peak demand (although it has been used for baseload generation also). It has a maximum capacity of 100 MW.

There is no public information available regarding the consents for this site. The design life of the Junction Road plant was expected to be about 25 years, although with refurbishment the unit life could be extended.

4.9 McKee (OCGT)

The McKee plant is owned by Nova Energy. It was commissioned in 2012 and is located in Taranaki near the McKee Mangahewa Production Station.

The plant uses two OCGT units fuelled by natural gas from the Mangahewa and McKee fields. It has a maximum capacity of 100 MW and is used to

[17] See FY22_Annual_Report.pdf (genesisenergy.co.nz)
[18] See hy22-interim-report-270222-final.pdf (genesisenergy.co.nz)
[19] See Genesis Energy to phase out Huntly coal use | RNZ News

[20] See page 8, https://media.genesisenergy.co.nz/genesis/investor/2022/Genesis%20Energy%20-%20Biofuels%20Insights.pdf

provide energy to the grid during periods of peak demand (although it has been used for baseload generation also).

The McKee plant's consent for water discharge expired in 2021, but has presumably been renewed. Other consents expire in 2031 and beyond. The design life of the McKee plant is thought to be about 25 years, although with refurbishment the units could last longer.

4.10 Stratford Peakers (OCGT)

The Stratford Peaker plants are owned by Contact Energy. They were commissioned in 2011 and are located in Taranaki at the same site as Contact's TCC plant.

The Stratford Peakers use two fast-start, high-efficiency turbines that run on natural gas from the nearby Ahuroa Gas Storage Facility. They have a combined capacity of 210 MW and are used to provide electricity to the grid during periods of peak demand.

The design life for the Stratford Peakers was expected to be about 25 years, although with refurbishment the units could have a longer operational life.

4.11 Taranaki Combined Cycle (CCGT)

The Taranaki Combined Cycle (TCC) plant is owned by Contact Energy. It was commissioned in 1998 and is located in Taranaki at the same site as Contact's Stratford Peaker plants. It is expected to be decommissioned after the 2024 winter.

The TCC plant uses a single CCGT unit that runs on natural gas from the nearby Ahuroa Gas Storage Facility. It has a maximum capacity of 377 MW and is used to provide baseload energy to the grid.

The design life of the TCC was expected to be 25-30 years. Contact had planned to retire the plant in 2023 as refurbishment costs were estimated to be more than $50 million (later revised to $80m). In June 2022 it announced that it had received engineering advice that supported running the TCC for an additional 750 operational hours. It now plans to decommission the plant around 2024.

4.12 Whirinaki (OCGT)

The Whirinaki plant is owned by Contact Energy. It was commissioned by the government in 2004 and later sold to Contact in 2011. It is located in Hawkes Bay north of Napier.

The Whirinaki plant uses three OCGT generators fuelled by diesel. It has a maximum capacity of 155 MW and is used to provide electricity to the grid during periods of peak demand or gas constraints.

Resource consents require water injection to control exhaust emissions. No other consent information is available. The design life of the Whirinaki plant was expected to be about 25 years (until 2029) without refurbishment.