2 December 2024

Monthly security outlook, December 2024 - February 2025

Market monitoring monthly report

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1. Summary

1.1. The Government Policy Statement outlines expectations for the electricity industry. Paragraph 22(a) highlights the important role the Authority has in ensuring all information relevant to the supply and demand outlook is accessible to all stakeholders. This report contributes to fulfilling that expectation by forming the analytical foundation for public facing materials related to the security of supply outlook.

1.2. This report is additional to the work carried out by the system operator who provides information and short to medium term forecasting on security of supply. Our analysis is informed by thermal fuel information not available to the system operator. We have improved our thermal fuel information through our section 46 information gathering powers, requiring the provision of information from participants. This information provides us with better visibility of thermal stockpiles and supply arrangements. Section 47A allows the Authority to share information with certain agencies, subject to confidentiality requirements, The system operator is not one of the entities who we can share information with under section 47A. It is important for the system operator to have access to relevant information to perform its security of supply function and we are working to remove these barriers.

1.3. We use three scenarios that match high hydro with medium inflows, high thermal with low inflows and one in between based on historical data. The idea is to use a simple and transparent approach to bracket the possible future energy storage for both thermal fuels and hydro storage by using these three different thermal/hydro generation pairs.

1.4. The Authority considers this compliments the system operator's simulated storage trajectories that use modelled water values calculated using storage levels to determine thermal generation over 12 months. The Authority's simple three scenario approach, shorter three-month horizon, better thermal fuel data, and the use of historic hydro/thermal generation levels differentiate it from the system operator's more detailed market simulation-based approach.

1.5. This work is critical for the Authority as regulator and market facilitator to be able to act in a focused way. We intend to work with the system operator to identify gaps in, and opportunities to enhance, security of supply and market outlook reporting.

1.6. While the analysis draws on confidential and commercially sensitive information, any such information has been redacted to ensure that this document is able to be publicly released.

1.7. This report provides an outlook for the New Zealand electricity system from 2 December 2024 to 2 March 2025. Assumptions used for this analysis are described in Section 9.

1.8. Three scenarios are developed to forecast a range of possibilities:

(a) Scenario A – Median inflows, high hydro generation and low thermal generation.

(b) Scenario B – Between low and median inflows, medium hydro generation and medium thermal generation.

(c) Scenario C – Low inflows, low hydro generation and high thermal generation.

1.9. These scenarios use historic hydro inflow sequences and known thermal fuel contracted positions and deliveries to forecast possible hydro and thermal storage over the next three months.

1.10. Over the next three months:

(a) Forecast national hydro storage does not reach the watch status in any of the three scenarios.

(b) Hydro generation capacity is sufficient to meet forecast hydro demand in all three scenarios.

(c) Thermal generation and fuel are sufficient to meet forecast thermal demand in all three scenarios.

(d) Total thermal fuel storage is stable in Scenario A and decreases in Scenario B and C.

1.11. The outlook scenarios are repeated without Huntly 5 available to mimic the event of a large unplanned outage. Without Huntly 5 available, there are seven weeks where thermal generation/fuel cannot meet the forecast thermal demand in Scenario C. The extra demand on hydro during these weeks is between 1-30GWh per week, which means a small amount of extra stress may be placed on hydro storage if Scenario C was to eventuate without Huntly 5 available.

1.12. Scenario B has one week at the end of February where ~2GWh of extra demand will be placed on hydro storage if Scenario B was to eventuate without Huntly 5 available.

1.13. For the next three months, the reduced demand over summer, contracted coal and gas positions and above average starting hydro storage mean that overall risk is low.

2. The scenarios

2.1. Three scenarios are developed based on historical demand and generation. Demand for the next three months is calculated by increasing the 2019-23 historic average demand by 2% to account for increased demand, and then by 4% to account for extra generation required for transmission losses.

2.2. The amount of wind, geothermal and cogeneration is calculated using the 2019-2023 historical capacity factor of each generation type, multiplied by the installed capacity of each type for each week. This accounts for any new generation.

2.3. The remaining demand is then split between hydro and thermal using historical maximum, minimum and midpoint ratios of hydro:thermal generation. The amount of hydro and thermal generation required in each scenario is then applied to the known storage positions to forecast the range of possible storage positions in the next three months.

2.4. Figure 1, Figure 2 and Figure 3 show the forecast weekly generation composition for each scenario. Total demand is the same for all three scenarios, but the proportion of generation provided by hydro and thermal is different.

Figure 1: Generation split for the highest hydro/lowest thermal scenario.

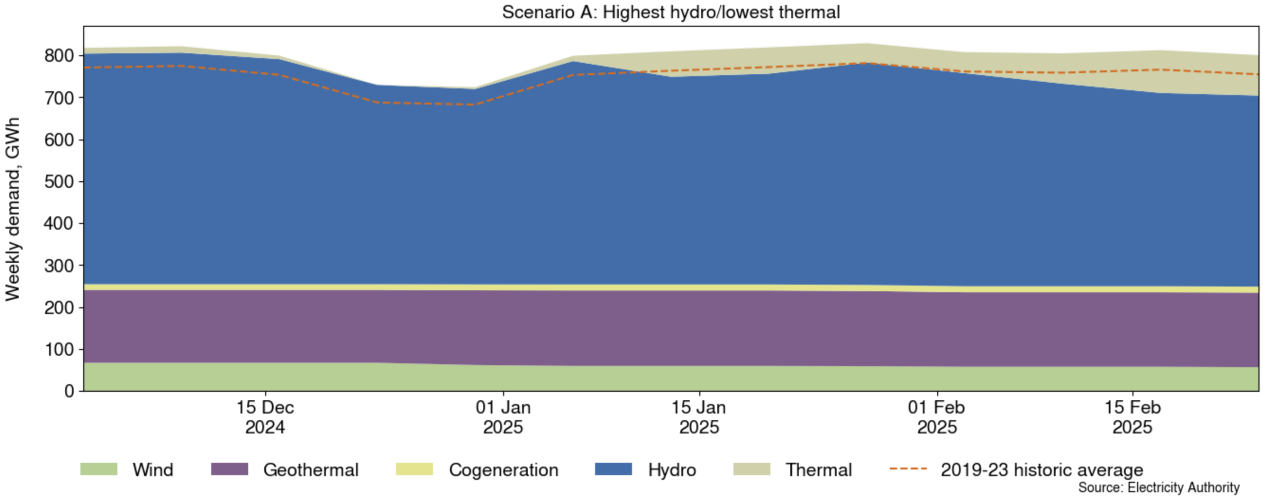


Figure 2: Generation split for the medium hydro/medium thermal scenario.

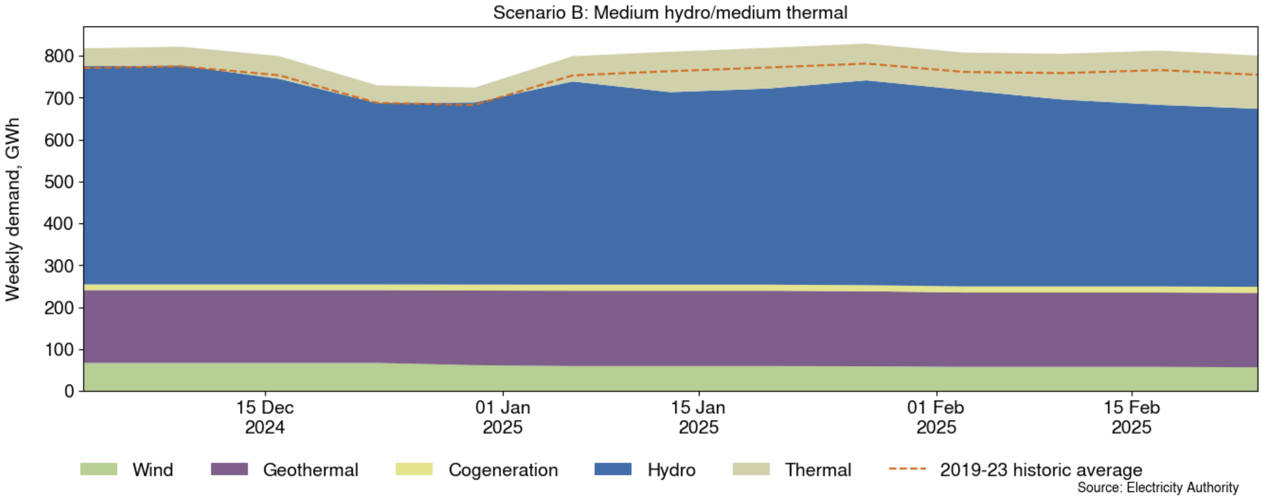
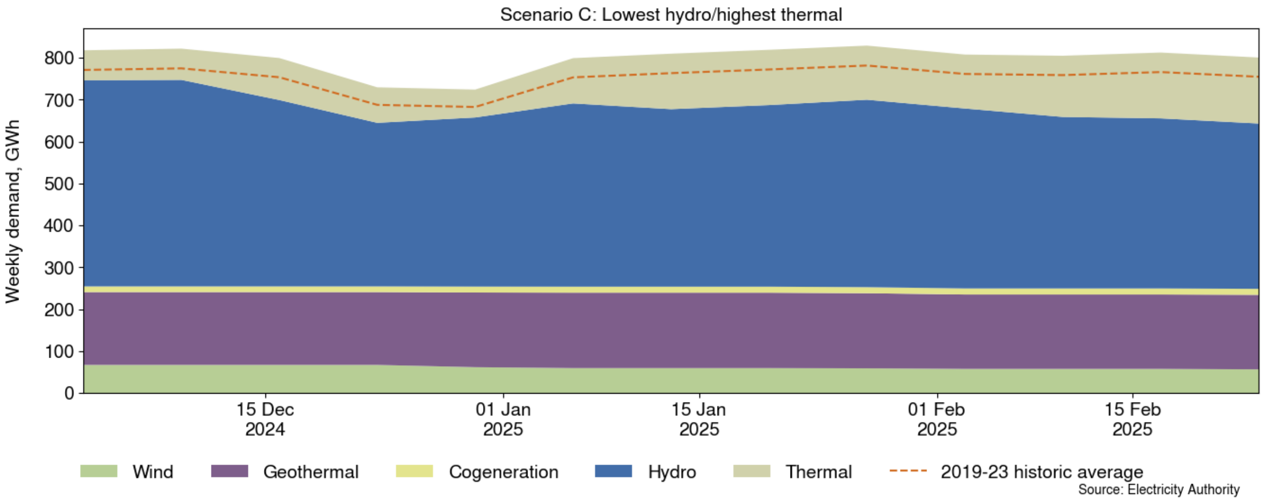


Figure 3: Generation split for the lowest hydro/highest thermal scenario.



3. Hydro generation and storage

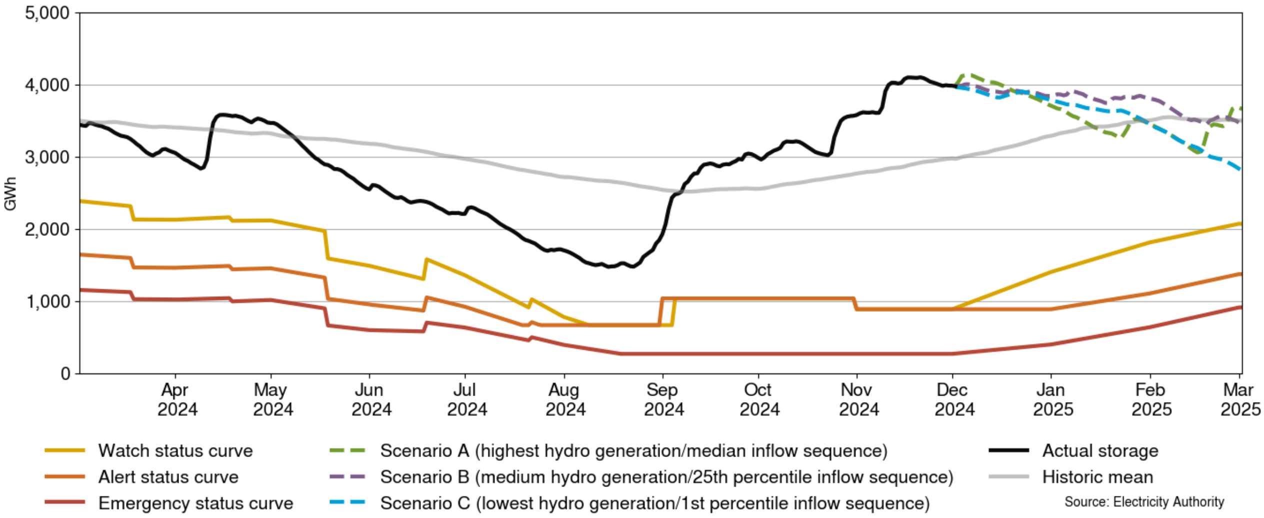
3.1. The hydro generation for each scenario shown in the previous section has been paired with an inflow sequence from the last 50 years. The highest hydro generation scenario uses the median sequence, the medium hydro generation scenario uses the 25th percentile sequence and the lowest hydro generation scenario uses the 1st percentile sequence. Higher inflow sequences are paired with higher generation to reflect that when low inflow sequences do occur, hydro generation generally decreases to conserve storage.

3.2. A regression model has then been used to estimate the daily change in storage for the hydro generation and inflow combination of each scenario. This provides an indicator of how storage may be impacted by low-to-medium inflow sequences.

3.3. Figure 4 shows estimated national hydro storage over the next three months for each scenario. For all three scenarios, the risk curves are not reached in the next three months.

3.4. Scenario A sees forecast hydro storage ~160GWh above the historical mean at the end of February, while Scenarios B and C have hydro storage forecast to drop ~50GWh and ~700GWh below the historical mean respectively.

Figure 4: Electricity risk curves and hydro storage for each scenario.[1]



4. Thermal generation and storage

4.1. Thermal fuel consists of contracted gas, stored gas in Ahuroa and the coal stockpile. Contracted gas supply and thermal demand in each scenario is used to calculate the amount of coal and Ahuroa storage usage.

4.2. Maximum generation capacity from each thermal unit is determined using historical capacity factors. Contracted gas is burnt in all available thermal units, prioritising baseload units first for their higher efficiency, and then peakers.

4.3. Any remaining required thermal generation is then split evenly between the coal stockpile and Ahuroa gas storage up to the available generation capacity of each relevant generator, or unevenly in the case of not enough generation capacity or fuel storage.

[1] Electricity risk curves sourced from Transpower, using the curves updated on 20 November 2024.

4.4. In all three scenarios, contracted gas, coal storage/deliveries and Ahuroa gas storage is sufficient to meet the forecast demand on thermal generation.

4.5. Total thermal fuel storage over the next three months is stable in Scenario A, and decreases in Scenario B and C.

5. N-1 sensitivity

5.1. The energy storage scenarios are repeated for the case that Huntly 5 is unavailable to simulate an N-1 scenario with a large unplanned outage. Figure 5 shows the weeks where demand on hydro generation is increased in Scenario C (high thermal/low hydro) because thermal generation and fuel cannot meet forecast thermal demand.

5.2. Figure 6 shows the hydro storage forecast with the extra hydro demand considered.

5.3. The last three weeks of February experience an extra requirement on hydro of 18-30GWh per week where thermal generation cannot meet the forecast thermal demand in Scenario C. The last two weeks of January and first two weeks of February also have a small extra demand on hydro of 1-4GWh per week. If Scenario C was to eventuate without Huntly 5 available, a small amount of additional stress would be placed on hydro storage.

5.4. Scenario B has one week at the end of February where ~2GWh of extra demand will be placed on hydro storage if Scenario B was to eventuate without Huntly 5 available.

5.5. Thermal generation and fuel are sufficient to meet forecast thermal demand in Scenario A without Huntly 5 available. This scenario sees total thermal storage decrease slightly from the start of December 2024 to the end of February 2025.

Figure 5: Extra demand requirement for hydro generation in Scenario C (high thermal/low hydro) - without Huntly 5.

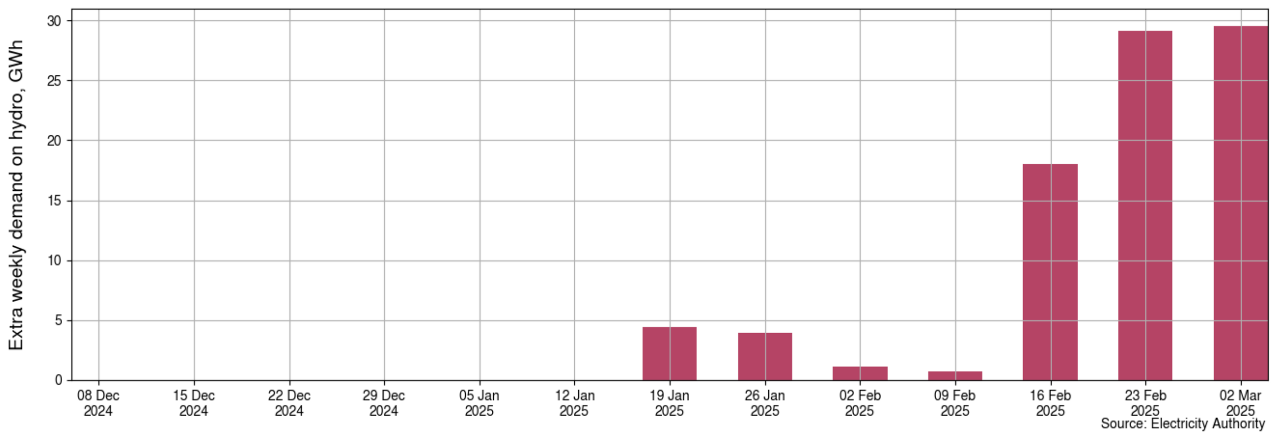
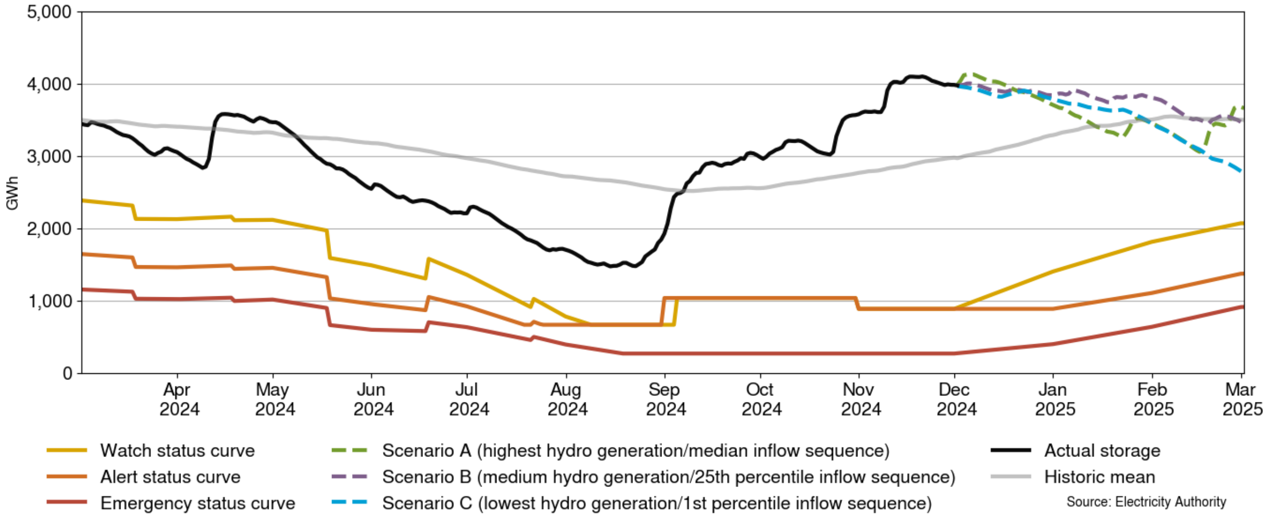


Figure 6: Electricity risk curves and hydro storage for each scenario – without Huntly 5.[2]



6. Outages

6.1. The use of historic capacity factors captures historic amounts of outages in the outlook analysis. The specific outages (greater than one day and greater than 100MW) between 2 December 2024 to 2 March 2025 are:

(a) Huntly 2 on outage until 14 March 2025.

(b) Stratford outage from 2-4 December.

(c) Manapōuri unit 6 on outage until 17 December.

(d) Manapōuri unit 4 on outage until 18 September 2025.

(e) Manapōuri unit 5 on outage 17 February-14 March 2025.

(f) Several other short Manapōuri unit outages

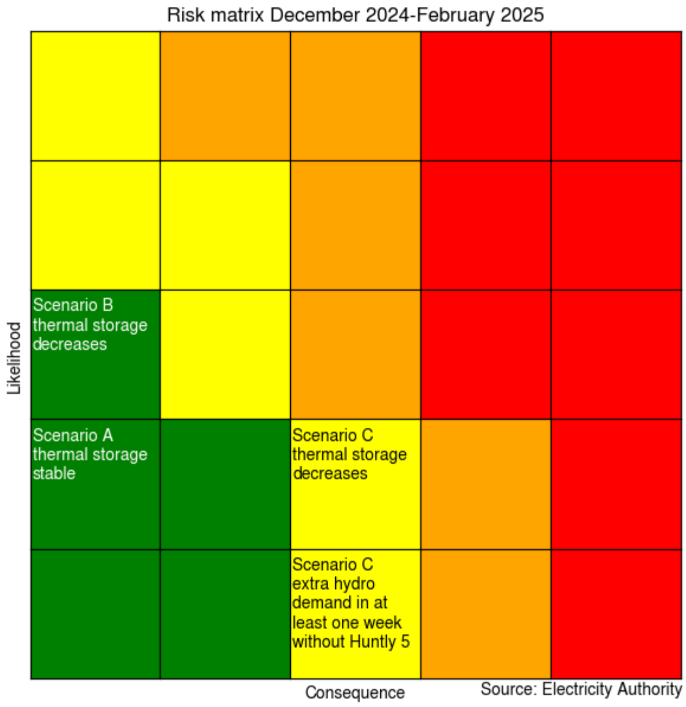
(g) Ōhau on outage from 1-2 March 2025.

7. Risk summary and actions

7.1. Figure shows the risk matrix summarizing the outlook for the next three months. Given the summer season, contracted coal and gas positions over the next three months and above average starting hydro storage, overall risk is low for the next three months.

[2] Electricity risk curves sourced from Transpower, using the curves updated on 20 November 2024.

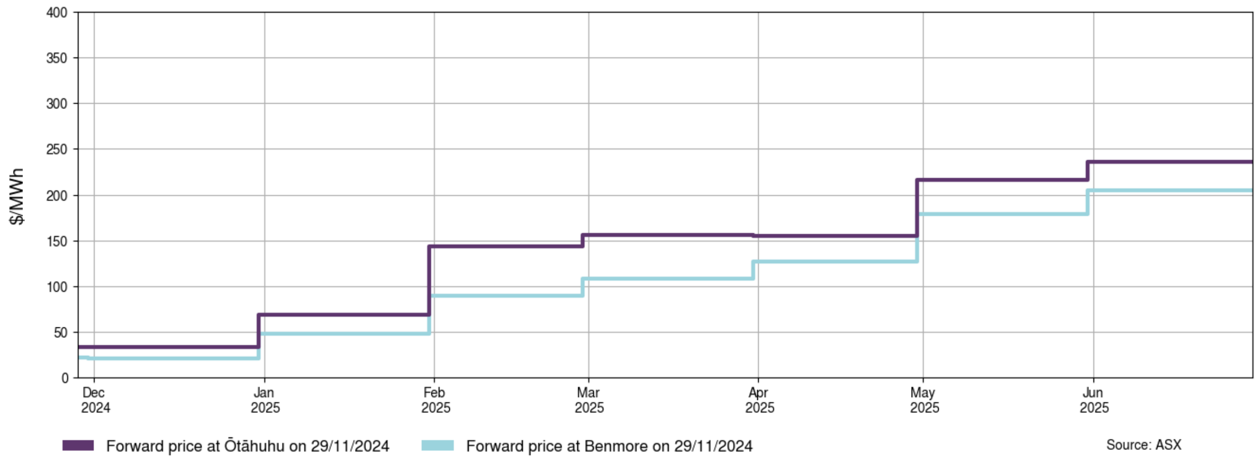
Figure 7: Risk matrix for December 2024 to February 2025



8. Spot price impacts

8.1. Figure show the ASX forward prices for Ōtāhuhu and Benmore as of 4 November 2024. These are the expected prices for Scenario B. Higher inflows (Scenario A) would likely result in prices below the ASX forward curve, while lower inflows (Scenario C), would likely result in prices above the ASX forward curve.

Figure 8: ASX forward monthly prices as of 29 November 2024.



9. Assumptions

9.1. Total New Zealand electricity demand is estimated by taking the 2019-23 historic average demand for the week, increasing by 2% to account for demand growth, and increasing by 4% to account for transmission losses.

9.2. 2019-23 historic capacity factors for wind, geothermal and cogeneration (Table 1) are used with the latest installed capacity to estimate the amount of demand met by these generation types.

Table 1: Monthly generation capacity factors.

Capacity factor	Wind	Geothermal	Cogeneration
January	0.280	0.832	0.344
February	0.271	0.822	0.345
March	0.253	0.826	0.337
April	0.286	0.830	0.283
May	0.277	0.831	0.242
June	0.308	0.830	0.203
July	0.332	0.850	0.236
August	0.308	0.866	0.340
September	0.383	0.824	0.318
October	0.358	0.819	0.324
November	0.336	0.780	0.280
December	0.316	0.804	0.325

9.3. The remaining generation is then split between hydro and thermal generation. The ratio of hydro:thermal generation was calculated for each week during the report period over the previous five years. The highest proportion of hydro generation for each week was then used for the highest hydro generation scenario, and the lowest proportion was used for the lowest hydro generation scenario. The midpoint between these two proportions was used for the medium hydro generation scenario. Thermal generation is then assumed to contribute the remaining generation in each scenario.

9.4. The thermal generation is calculated by considering forecast contracted gas supply, gas storage and coal stockpile. The maximum operating capacity of each thermal unit is calculated by multiplying the installed capacity by the annual average capacity factor for the unit from 2016-23, with some exclusions:

(a) Huntly 5 and TCC exclude 2021 and 2022 because of wet years resulting in decreased usage. 2023 is excluded because of both units having extended outages.

(b) Rankines use their combined July 2024 capacity factor to represent a scenario where all three units were available to generate.

Table 2: Thermal unit capacity factors and heat rates.

	Capacity (MW)	Capacity factor	Heat rate (TJ/GWh)
Huntly 5	400	0.77	7.4
Huntly 6	50	0.18	10.525
TCC	377	0.33	7.4
Stratford	200	0.18	9.5
McKee	100	0.31	10.525
Junction Road	100	0.29	10.525
Rankines	750	0.71	10.9

9.5. Contracted gas is burnt in all available thermal units, prioritising baseload units first for their higher efficiency, and then peakers. Any remaining thermal demand (if any) is then met from a 50/50 split between Ahuroa storage and the coal stockpile. In the case of insufficient generation capacity for a 50/50 split between Ahuroa and coal storage, Ahuroa gas is used to run Contact and Nova units to their capacity, and coal makes up the remainder (up to the Rankine capacity limit).

(a) The low range of contracted gas supply is combined with Scenario C (high thermal/low hydro).

(b) The high range of contracted gas supply is combined with Scenarios A and B.

(c) Any contracted gas above that required for Contact and Nova to operate their units at capacity is modelled as injected in Ahuroa.

9.6. Ahuroa storage is assumed to be entirely available for electricity. In reality, Ahuroa may also be used to supply other gas users.

9.7. Any weeks where thermal fuel and capacity is unable to provide the forecast thermal demand, the remaining thermal demand is assumed to be extra demand on hydro.