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Review of winter 2024

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1. Summary

1.1. Between July and mid-August 2024 spot prices were much higher than average for winter. Between 2018 and 2023, the average winter price was around $180/MWh. However, in early August the average daily price reached $820/MWh. These high prices resulted from high electricity demand and low wind generation during a fuel shortage, due to low hydro storage and gas supply.

1.2. Over autumn and winter 2024, several different factors coincided to push up wholesale electricity prices. Firstly, hydro storage had steadily declined since the last major inflow in April. Since electricity in New Zealand is heavily dependent on hydro generation, when lake levels are declining, the value of the water in reservoirs increases. Usually when hydro storage falls and prices rise, thermal generation increases to meet demand.

1.3. Gas production has steadily declined since 2018. As demand for thermal generation increased over 2024, this pushed up the price of gas. Generators were unable to run baseload thermal generation at full capacity due to low gas availability. This increased the system's reliance on coal and, to a lesser extent, diesel to meet demand. However, the coal stockpile also dropped significantly during August 2024.

1.4. When cold weather increased demand in the first half of August, coinciding with low wind generation, the spot price increased as generators increased offers to signal fuel scarcity.

1.5. In the short term, these high wholesale prices reflected the risk of running out of stored water. As storage declined, many hydro operators raised offer prices to discourage hydro-dispatch, to ensure future hydro storage would not run out. However, thermal generators did not have gas available to run at full capacity, and increased offer prices to prevent running out of thermal fuels. This fuel shortage resulted in a dramatic price increase.

1.6. The industry responded in several ways to alleviate this fuel shortage and bring down electricity spot prices.

1.7. To help alleviate low hydro storage, Meridian called on its first tranche demand response option with the Tiwai aluminium smelter. By the end of July this had escalated to the maximum option, with the smelter reducing its demand by 185MW. Over winter this saved an estimated 330GWh of energy, which is equivalent to 7% of New Zealand's total hydro storage.

1.8. On 13 August Methanex halted production and sold its gas to Genesis and Contact, which was used to increase gas generation and dropped spot prices to around $400/MWh.

1.9. Then in late August, high rainfall, particularly in the lower South Island, increased hydro storage significantly, and resulted in average prices falling to around $100/MWh in September. Wind generation also increased in September and thermal generation dropped significantly.

1.10. Despite the very high prices in early August, the overall energy margin for the large gentailers was lower in early August than it was in July and September. These gentailers are vertically integrated, so while generation revenue rose as prices increased, the cost of meeting retail and hedge obligations also increased. Also, a high amount of thermal fuel was being used in August, which increased the cost of generating electricity.

1.11. During the high prices in August, two forestry-based industrial electricity users, Winstone Pulp International and Pan Pac either turned down or halted production. Then in September, Winstone announced its permanent closure of its two mills at Tangiwai and Karioi, while Oji also announced they would close their Penrose paper recycling facility. Winstone and Pan Pac have publicly stated that high electricity prices as a big factor in their closures or temporary demand reductions. Our analysis found that all three of these industrials had access to a similar quantity of hedges, and that each had access to enough hedges ahead of time to be fully hedged for July-September 2024.

1.12. Most electricity consumers, including all residential households, were sheltered from these high prices through retailer hedging. However, some retailers removed promotions or all their offerings from websites such as Powerswitch and some stopped taking on new customers. This may have reduced consumer choice at this time. There was a small decline in the number of ICPs with a small- or medium-sized retailer during July and August, as more consumers switched to larger retailers.

1.13. Depending on inflows and rainfall between now and next winter, there is a risk we could see some of the same challenges again. Gas production shortfalls are expected to continue, and Meridian will be unable to call on Tiwai for the maximum demand response due to a stand down period. Therefore, the industry and the Authority need to find ways to reduce the risk of fuel shortages.

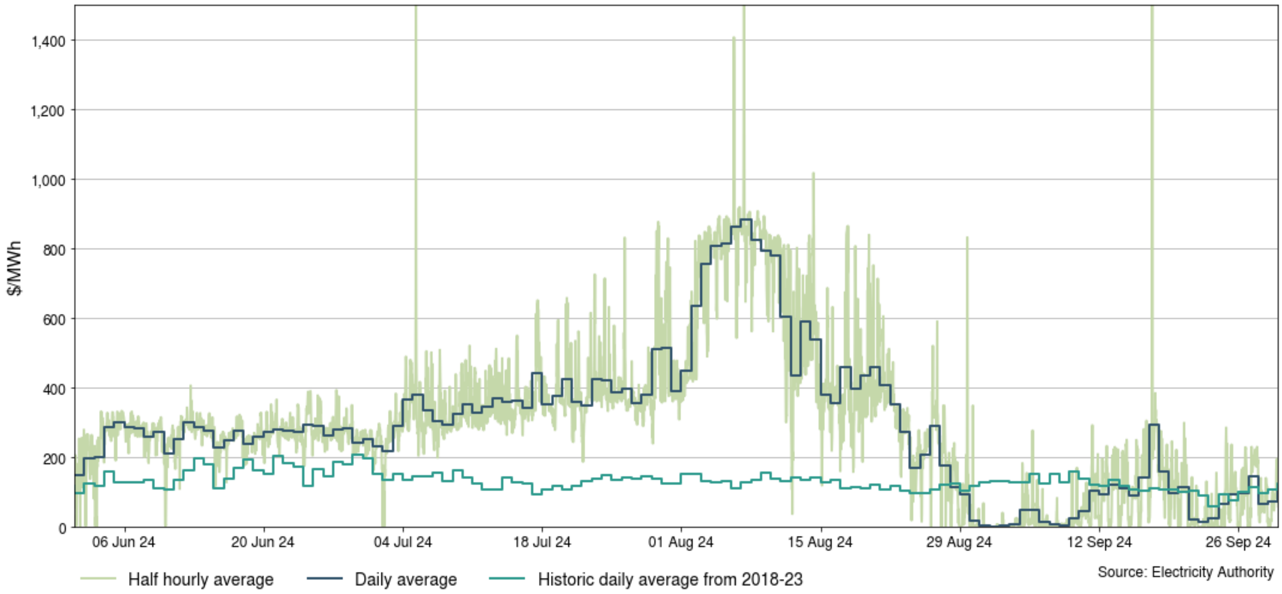
1.14. The Authority has work currently underway to help address this risk prior to winter 2025. This includes outage co-ordination enhancements, scarcity pricing review, increasing transparency of thermal fuel availability, the power innovation pathway, intermittent generation forecasting arrangements and extended reserve implementation. The Gas Security Response Group is also exploring the feasibility of LNG imports. In the longer term, we are also planning to review security standards assumption documents (SSAD) and BESS enhancements.

2. Overview of market conditions

Spot prices were very high, especially in early August, before dropping in September

2.1. In winter 2024, New Zealand's wholesale electricity prices increased from roughly \$300/MWh in early July to up to \$820/MWh in early August. During July and August prices were above the historical daily average. Prices eased in late August and September to below \$200/MWh and were usually below the historical average. There were still the occasional high prices, mainly related to high demand or forecasting inaccuracies. These fluctuations in wholesale prices can be seen in Figure 1.

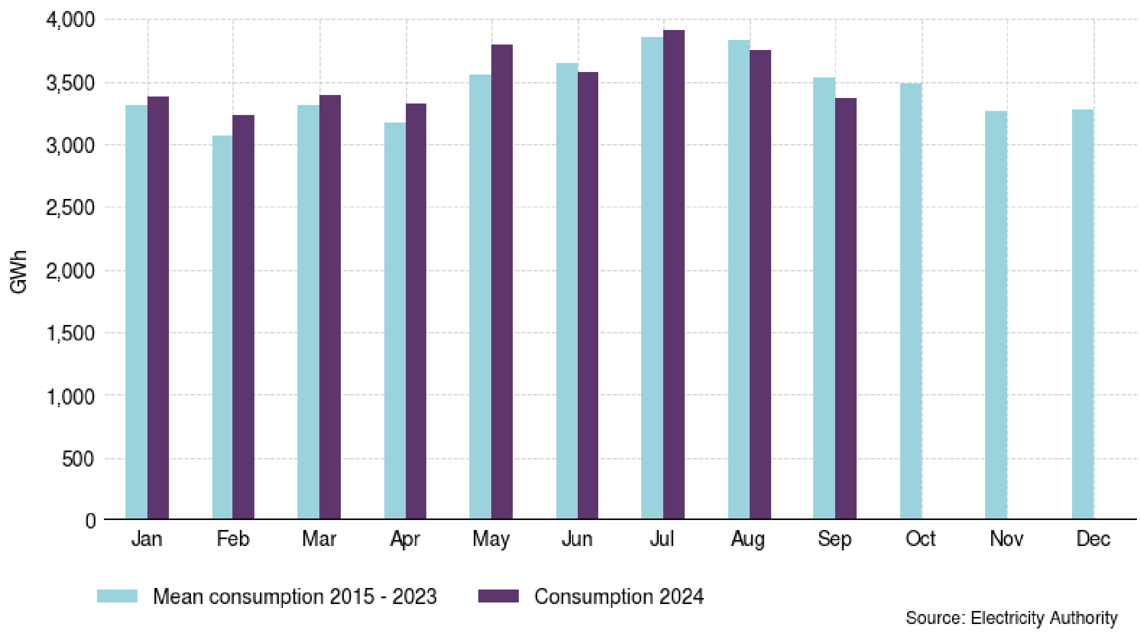
Figure 1: National average of wholesale prices from June-September 2024



Demand was higher when compared to previous years

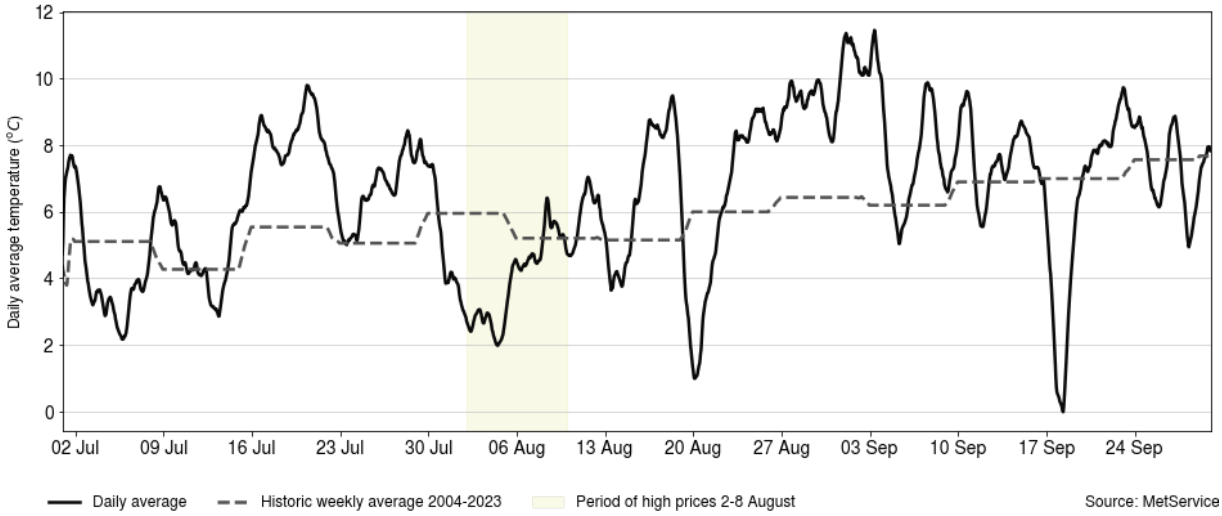
2.2. Household demand for electricity in New Zealand is highly seasonal. Typically, national demand for electricity peaks sometime in July and August and then declines as spring brings warmer weather and longer days. Demand was higher than historic average most months between January and July, excluding June, as indicated in Figure 2. A cold snap in May increased consumption further above the historic average, which had an early impact on hydro storage in late Autumn.

Figure 2: Monthly electricity consumption in 2024 compared to recent years



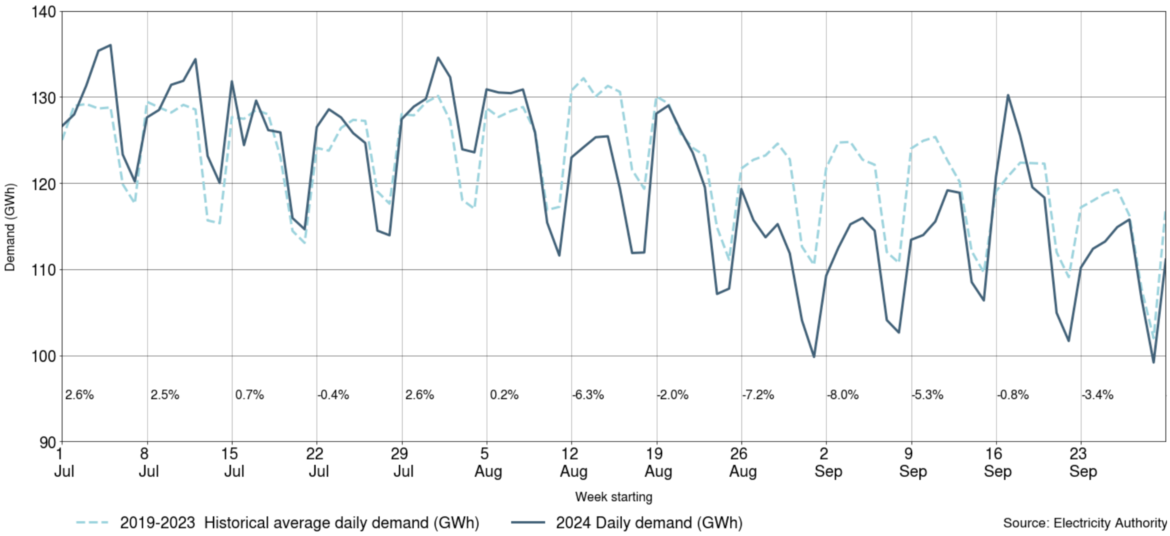
2.3. In early August, New Zealand experienced cold weather, with the resulting higher electricity demand pushing up electricity wholesale prices - during a time of low fuel availability. But warmer days toward the end of August (see Figure 3) reduced household electricity consumption.

Figure 3: Daily apparent temperatures across Wellington, Auckland and Christchurch, July-September 2024



2.4. Demand response from Tiwai and other industrials lowered total demand in August and September by between 50-205MW. This will be explored further in Section 9.

Figure 4: Daily demand July to September 2024 compared to recent years

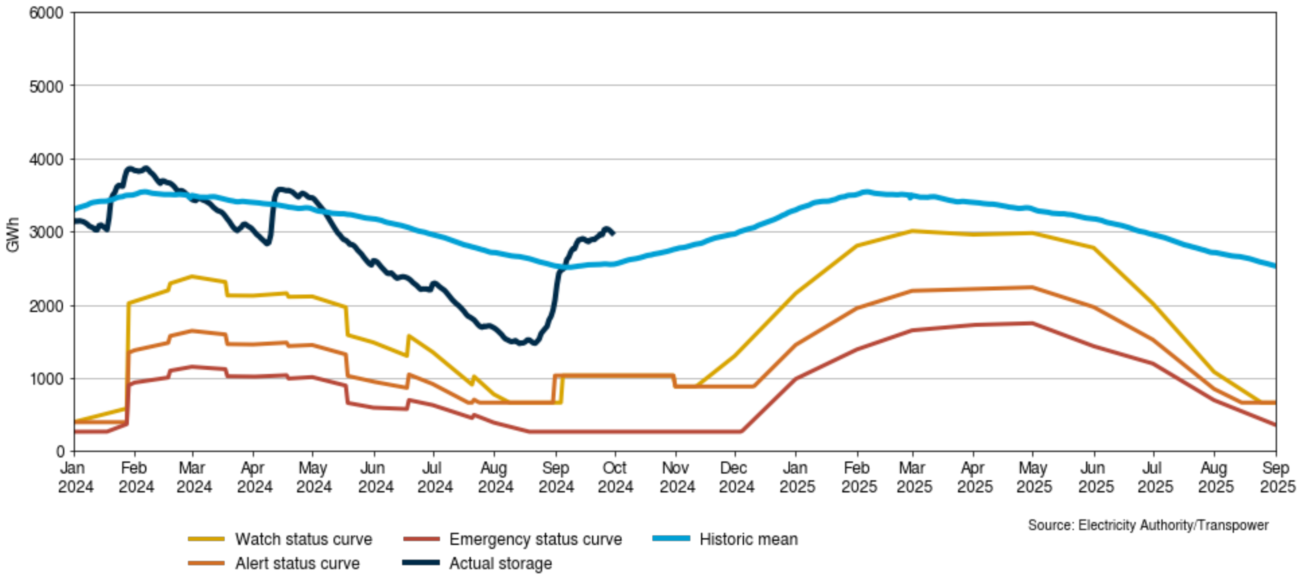


Hydro storage rapidly declined until mid-August

2.5. During summer and the early autumn season of 2024 the El Niño Southern Oscillation (ENSO) was in its El Niño phase. This phase typically brings more rainfall to the major southern catchments. However, this summer was characterised as a 'dry' El Niño year, where rainfall was mostly below average for the summer and autumn period. This was also compounded by a dry spring/summer season in 2023 which meant all lakes, bar Taupō, began the year below 100% of their mean storage.

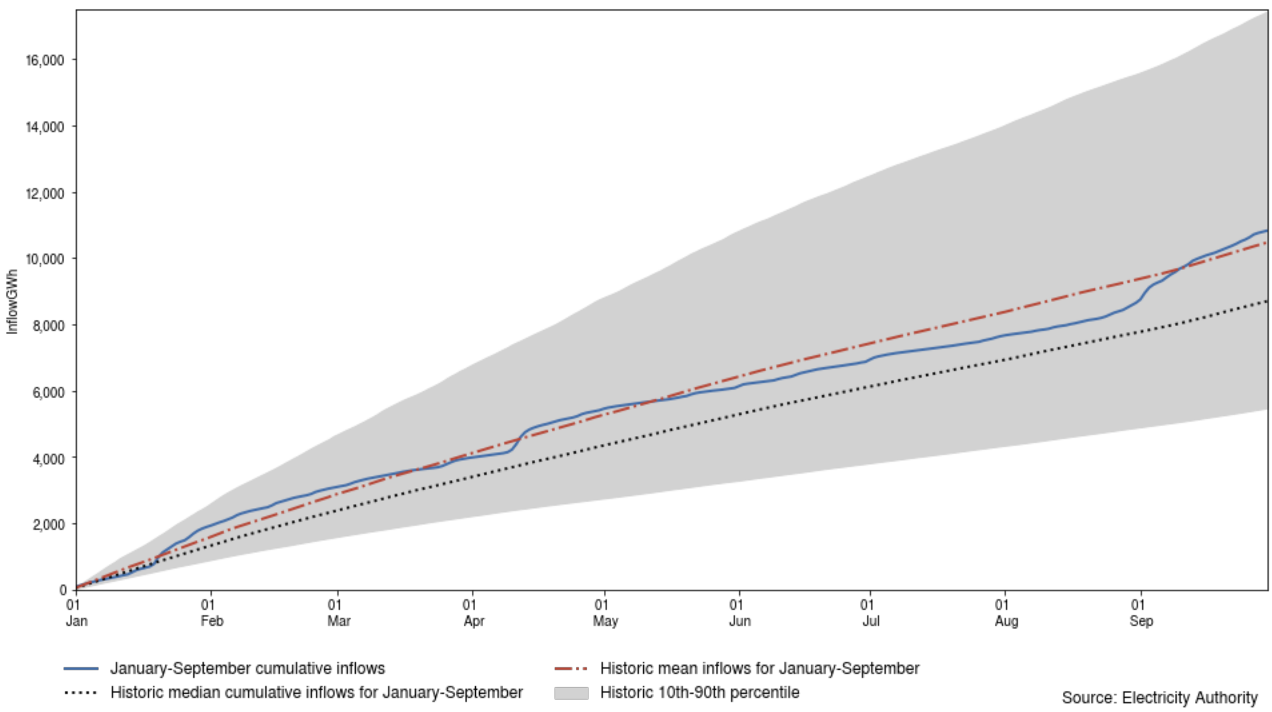
2.6. Total national storage started at around 3,000GWh in January, which is about 10% below the mean. Two large inflow events increased storage to just above the mean, by mid-April. Between April and August 2024, hydro storage steadily declined, as there were no significant inflows and higher hydro dispatch due to high electricity demand. Storage reached 1,500GWh, a six-year low, in early August.

Figure 5: Hydro storage levels and electricity risk curves between January-September 2024



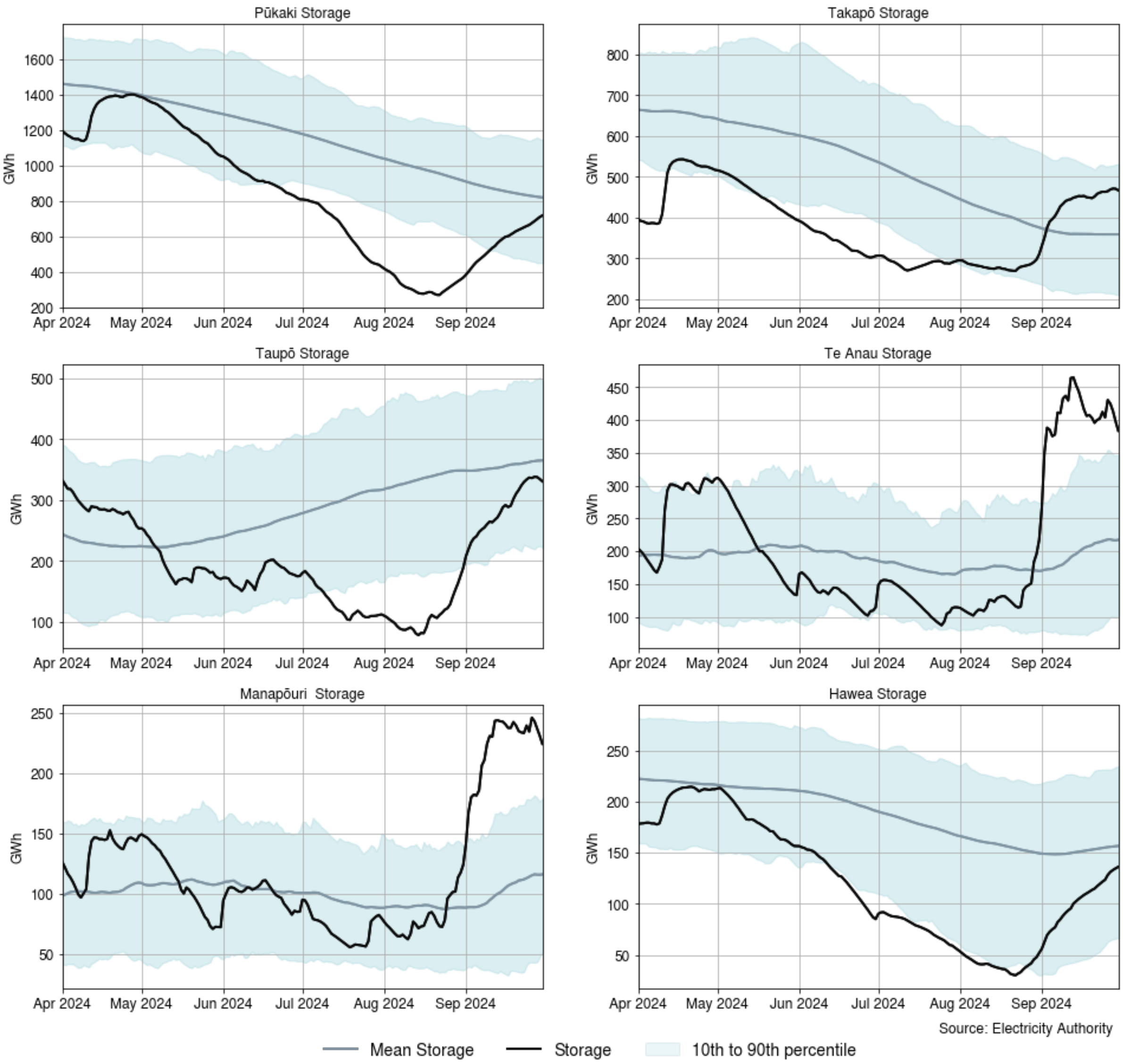
2.7. Total inflows were tracking close to the mean at the beginning of January and beginning of May. However, low inflows after May saw total inflows fall below mean, as seen in Figure 6. During the last week of August, inflows increased, particularly in the Southland and Otago region. Between 20 August -16 September storage increased from ~1,500GWh to ~2,700GWh.

Figure 6: Cumulative inflows for major lakes 2024 compared to historic mean, median and 10-90th percentiles



2.8. Figure 7 shows hydro storage by major lakes between April and end of September and the 10th to 90th percentiles. Pūkaki, the largest storage lake, was at mean hydro levels in May, but fell below its 10th percentile by June, and continued falling until 22 August. Pūkaki's storage reached ~267GWh its lowest value since 1997[1]. All the major lakes had storage below their respective mean by August, with Taupō and Hawea also below their 10th percentiles.

Figure 7: Major lakes hydro storage levels, April-September 2024



Potential shortfalls were forecast if low gas and low wind reduced available generation

2.9. Potential for generation shortfalls in winter were signalled ahead of time. The New Zealand Generation Balance[2] (NZGB) June report stated there were no potential negative balances for N-1 or N-1-G[3] for the base scenario, but there were numerous low balances for N-1-G from 19 July to 16 August. Low gas/low wind and low gas/no wind scenarios showed

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[1] Storage reached 227GWh on 11 November 1997

[2] Provided by Transpower

[3] These forecasts are based on data supplied by the Planned Outage Coordination Process and are used for outage planning. They give an early indication of times when available generation could be insufficient to meet peak load. Peak load is calculated by adding 2% growth to the maximum peak, the loss of the largest risk setter (a large generator or HVDC pole). Likewise, N-1-G is the system's capacity to cover, over the peak, the loss of the next largest generation risk setter, if the largest risk setter were to become unavailable.

several negative balances for N-1-G throughout the winter months. These negative balances indicated that there could be capacity risk if there was a shortage of gas to firm wind generation during a cold winter day when demand was high, particularly if one of the large generation units were not available.

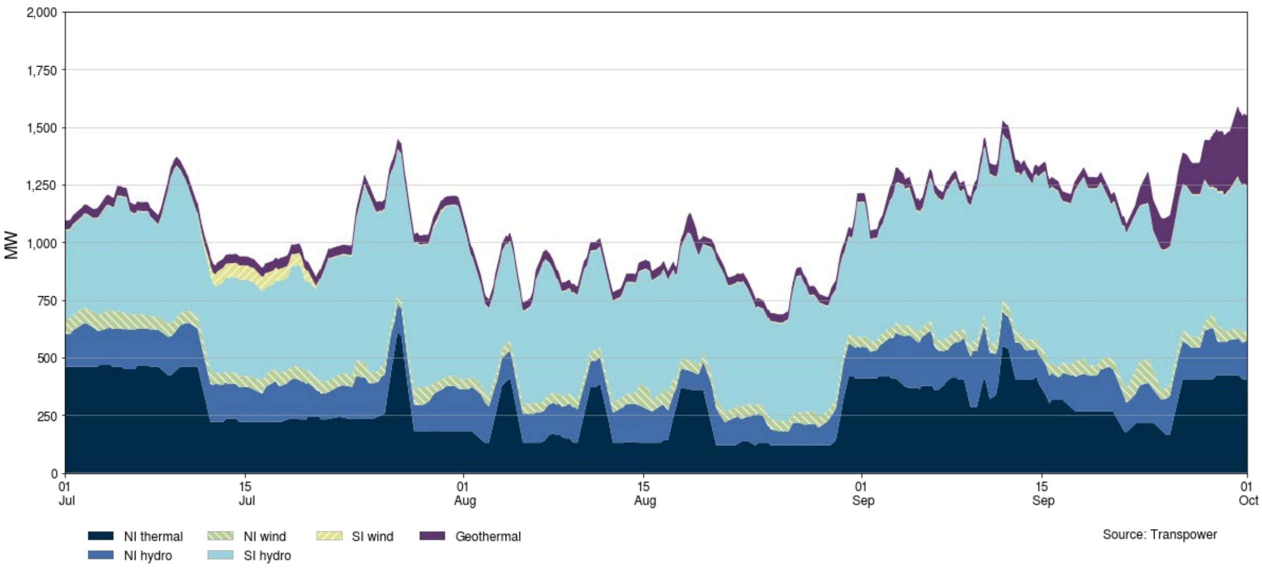
2.10. The July NZGB report[4] indicated more July dates falling into potential generation shortfall, as well as reporting shortfalls in August and September. Firm capacity scenario (which replaces the former low gas/low wind scenarios) shows low residuals for N-1 through August as well as potential shortfalls for N-1-G.

2.11. There were Customer Advice Notices (CAN) issued on 19 June and 26 June to advise of potential negative generation balances for N-1-G base scenario for several dates in July. For the dates in these notices the N-1 margins were mostly above 300MW. During July there were no low residual CANs or any further notices regarding the dates advised in June suggesting participants responded to the notices to reschedule any non-urgent maintenance outages.

Due to the fuel situation, non-urgent outages were moved to September

2.12. Figure 8 shows daily rolling average outages by generation type. Generation outages were usually below 1,000MW in August as many generators delayed non-urgent maintenance to ensure capacity was available. September saw a large increase in outages, particularly from thermal units at the start of September and geothermal units at the end of September. Increased hydro storage along with reduced demand as the seasons changed resulted in less reliance on thermal and geothermal generation, allowing delayed and rescheduled maintenance to proceed.

Figure 8: Daily rolling average outages by generation type



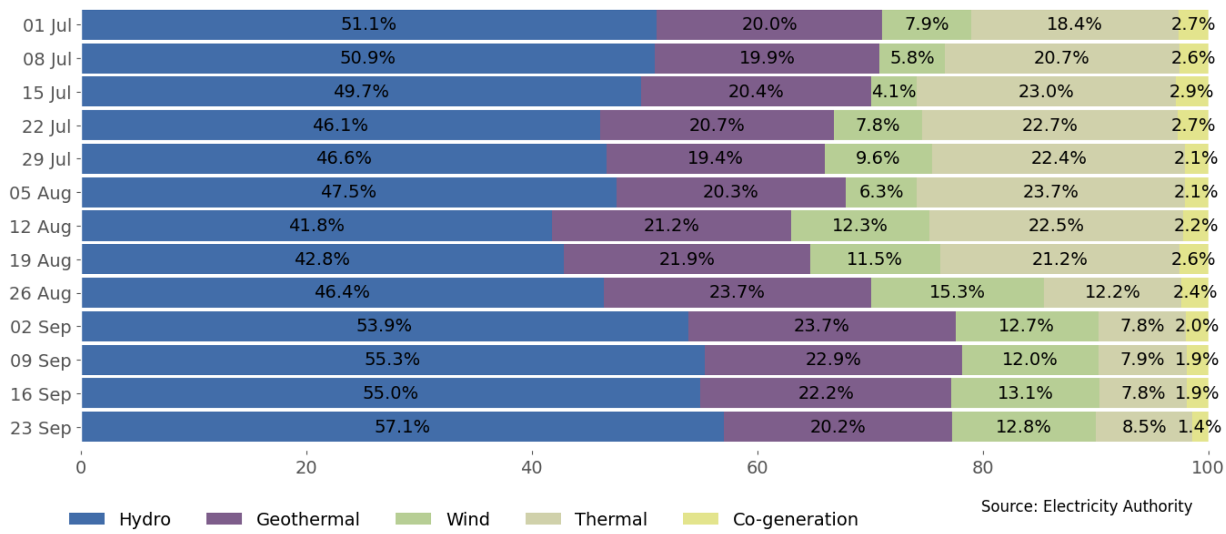
[4] The July NZGB report included generation balance calculations based on an updated Yes Energy Tesla load forecast model and outages taken from POCP on 2 July. July reporting was based on previous model meaning negative balances were reported on as per the June report. The August outlook in this report was based on new model.

3. Thermal generation was needed when hydro and wind generation was low

3.1. The lack of significant inflows since the beginning of April put extra pressure on hydro storage as winter approached.

3.2. Figure 9 shows the weekly proportions of each generation type from 1 July to 1 September inclusive. From July 2023 to June 2024, weekly generation from hydro ranged between 48-68% of generation, with only two weeks across this period where hydro generation dropped below 50%. However, from mid-July to late August 2024, hydro generation was consistently less than half of total generation.

Figure 9: Weekly percentage of generation by type 1 July - 29 September 2024



3.3. When hydro storage levels reached record lows, the weekly proportion of hydro generation dropped as low as 42% from 12-18 August. Periods of high wind generation through August also reduced the proportion of hydro generation.

3.4. There were also increases in the proportion of generation from hydro and reduction in thermal from the last week of August as inflows increased in the hydro catchment areas in the southwestern South Island.

3.5. Between July and September geothermal generation, which runs as baseload generation, made up between ~20-24% of weekly load requirements. The commissioning of Tauhara resulted in an overall increase in geothermal generation. Tauhara completed their reliability run at the end of June and has been mostly running at ~155-159MW.

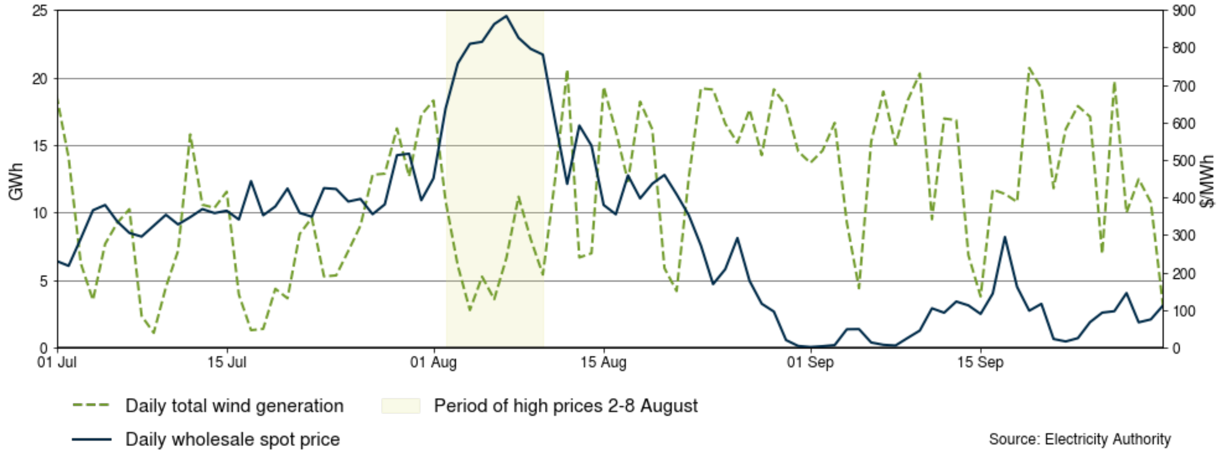
3.6. However, more baseload generation this winter was thermal generation. Increased thermal generation is not unusual for the winter period as demand increases but the fall in hydro generation over this period resulted in a higher requirement for thermal generation, which peaked at 23.7% in the week starting 5 August. During this time TCC, Huntly 5 and three Rankines were running concurrently, with support from all the peakers not on outage.

3.7. National wind generation capacity increased when Harapaki was fully commissioned in July 2024. From the second week of August wind generation reached above 10% of total generation each week. In the last two weeks of August generation was above 1,000MW in some trading periods.

3.8. Inflows to key catchment areas in September saw an increase to the proportion of generation from hydro to consistently above 50%. There was also at least 12% of weekly generation coming from wind. This in turn saw a drop in the percentage of generation from thermal plants.

3.9. When wholesale prices were highest in early August 2024, wind generation was often generating below 300MW, despite national wind capacity of over 1,000MW. These lulls in wind generation, together with high demand, declining hydro storage and high gas prices, led to wholesale electricity prices reaching over $800/MWh at times (see Figure 10, yellow highlight).

Figure 10: Daily total wind generation and daily average wholesale electricity price, July - September 2024

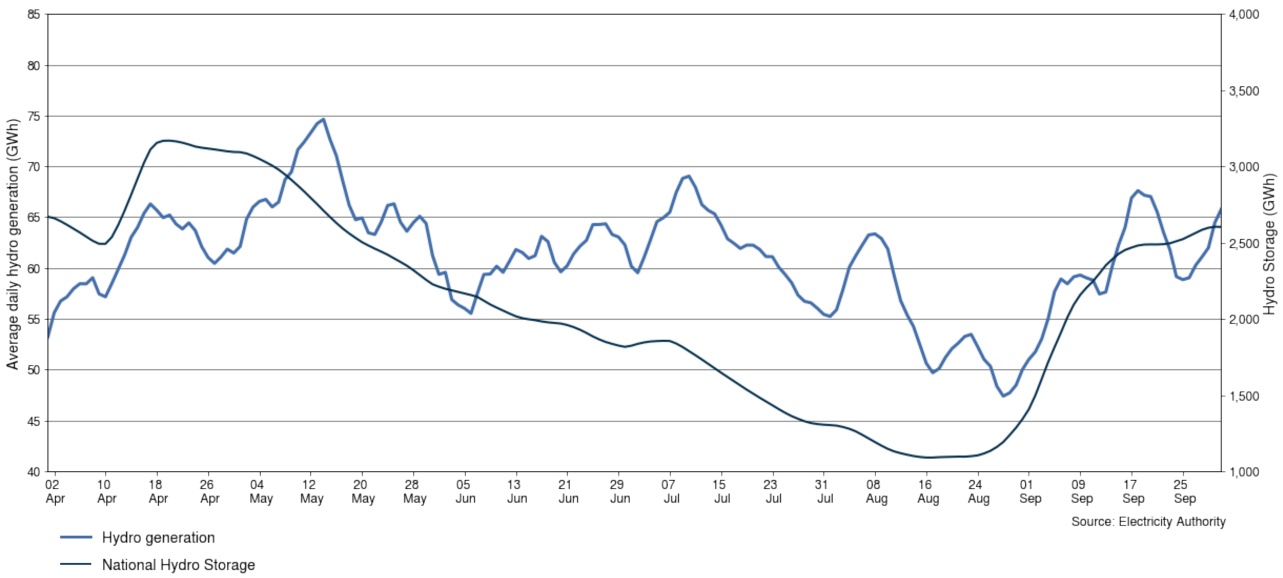


3.10. Figure 11 and Figure 12 show the seven-day rolling average hydro storage against the rolling average thermal generation and hydro generation respectively. A clear increase in generation from thermal can be seen as the hydro storage decreased over winter.

3.11. Throughout July and August daily generation from hydro decreased. From 11 August daily average hydro generation was consistently below 60GWh until mid-September. Daily thermal generation was above 25GWh until a significant dip in thermal from the last week of August due to a combination of both an increase in hydro storage along with a drop in demand.

Figure 11: National hydro storage and thermal generation (7 day rolling average) since 1 April 2024

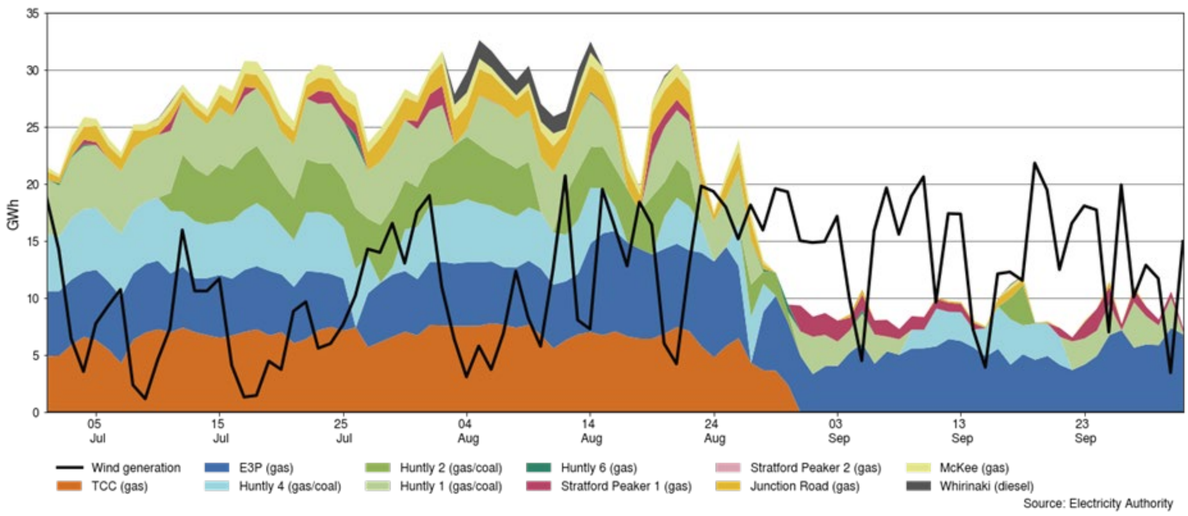
Figure 12: National hydro storage and hydro generation (7 day rolling average) since 1 April 2024



3.12. Figure 13 shows daily average thermal and wind generation from 1 July to 30 September 2024. We expect to see increased thermal generation during periods of low wind generation. This was evident around the first week of August where three Rankine units were running along with baseload generation from TCC and Huntly 5. This week also saw an increase to generation from thermal peakers to help cover demand.

3.13. However, there were periods in late July and mid-August where there was high wind generation, and still high output from thermal generation. This was due the low hydro storage situation causing the system to prioritise saving water rather than thermal fuels when wind was high.

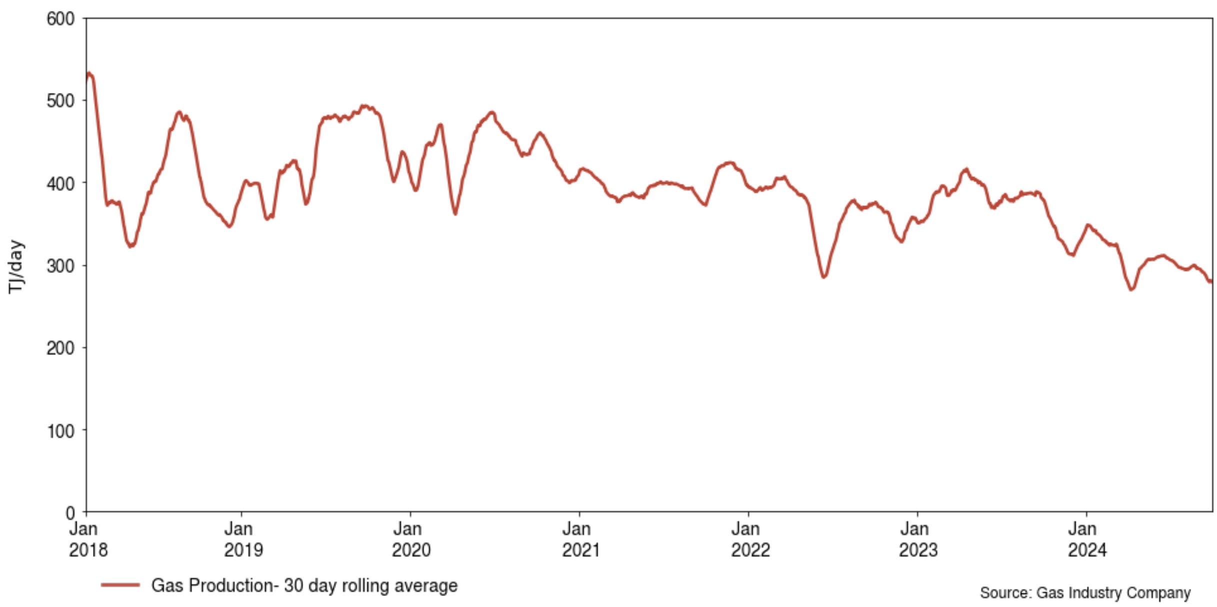
Figure 13: Daily average wind and thermal generation, July-September 2024



4. Wholesale gas production is lower than demand

4.1. Figure 14 shows the 30-day rolling average gas production at the major gas fields between 2018 and 2024, namely Pohokura, Maui, Kupe, McKee, Mangahewa, Turangi and Kowhai. Gas production was low this year, with an average production from these gas fields at 304TJ/day, down 18% from 2023 when production was on average 372TJ/day. This was already down from 435TJ/day in 2020. This fall in production has predominantly been driven by a fall in production at Pohokura from an average of 180TJ/day in 2019 to 45TJ/day in 2024.

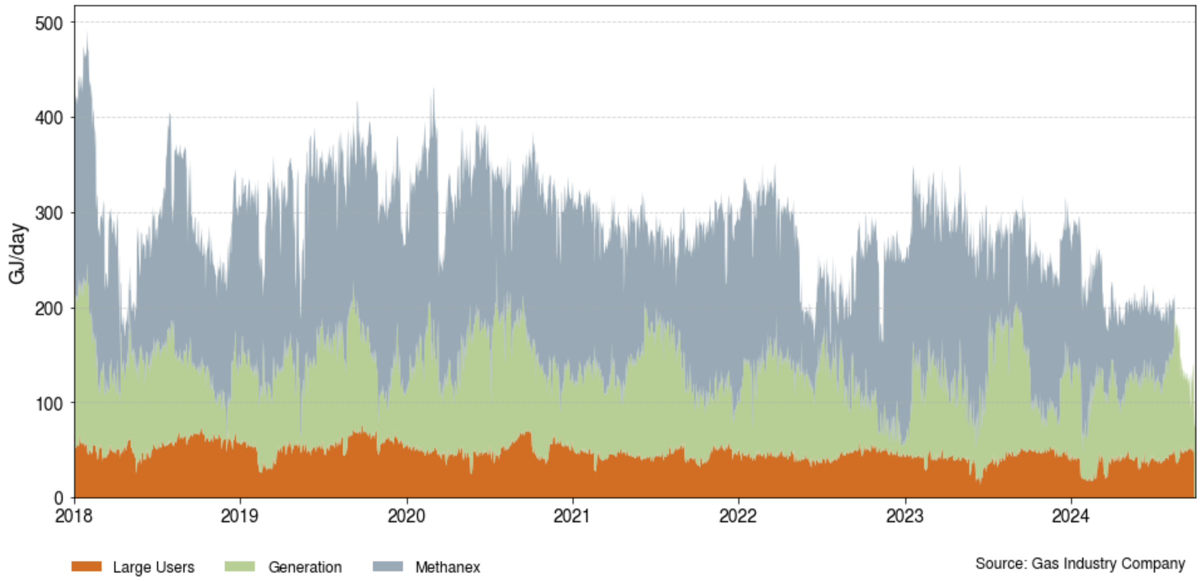
Figure 14: Daily gas production, 2018-2024



4.2. However, despite the fall in gas production, there continued to be high demand for gas. Figure 15 shows the daily consumption by the largest users of gas, namely Methanex, Genesis, Contact, Nova, Fonterra, Ballance, Glenbrook, Kinleith and (until 2022) Marsden Point. Demand from large users other than Methanex and generators has fallen about

15TJ/day, mostly due to the closure of Marsden Point refinery in 2022, but otherwise remains around 40TJ/day.

Figure 15: Gas consumption by Methanex, Generators and other large users, 2018-2024



4.3. Demand for gas for electricity generation varies year to year, with consumption of about 130TJ/day in winter 2023. Demand for gas for generation tends to be higher when hydro storage is low, and electricity demand is high.

4.4. Methanex has absorbed most of the fall in gas production, first closing down Waitara Valley in 2021 and then reducing production at Motunui. Methanex has stated its reduction in production is due to gas supply issues and it would have preferred to remain in full production rather than on-sell gas to other users.[5]

4.5. The decline in gas production while demand remained high caused gas spot prices to increase from around $15/GJ at the start of 2024, to a high of $54/GJ in August.

4.6. In mid-August a deal was reached between Methanex, Genesis and Contact which saw Methanex shut down its remaining production line and sell its contracted gas to Genesis and Contact. This resulted in a large drop in the spot price for gas and higher output from gas-fired generation. Towards the end of August, higher wind generation and hydro inflows also reduced reliance of thermal generation which contributed to lower spot gas prices.

4.7. Methanex was consuming around 50TJ/day prior to the deal, but this was low compared to consumption at 150TJ/day in early 2024, as Methanex had reduced production to a one train operation.

Ahuroa gas storage helped meet demand

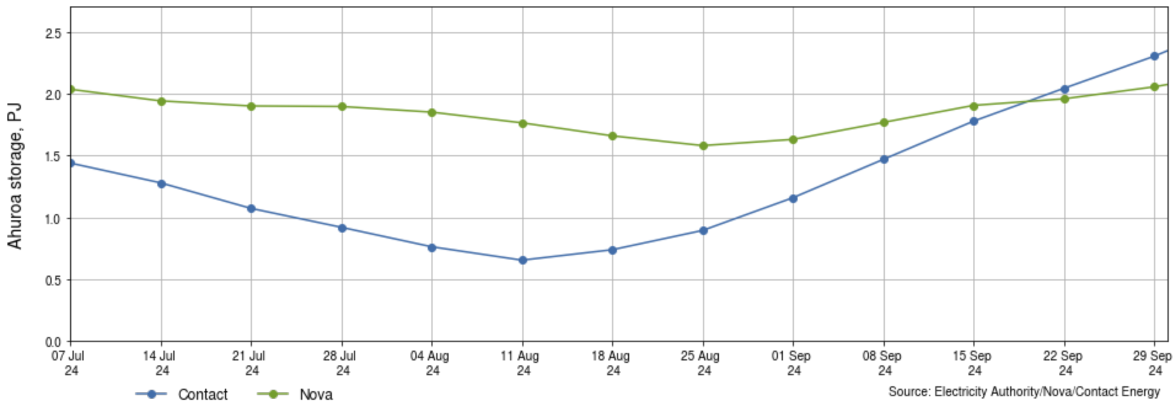
4.8. Ahuroa gas storage facility[6] allows for gas to be stored when production is higher than demand and withdrawn when needed. Both Contact and Nova use this facility to store gas. Figure 16 shows the Ahuroa storage for Nova and Contact that is available and accessible for electricity generation. It does not include pad gas which cannot be withdrawn. Both Nova

[5] https://www.energynews.co.nz/news/gas-supply/167240/methanex-shut-second-line-questions-action-gas-supply

[6] https://www.gasindustry.co.nz/data/gas-storage/

and Contact were withdrawing gas through July and early August. Contact began injecting gas after the Methanex deal was signed on 13 August, and Nova began injecting by the end of August. Overall storage fell in July and August and increased in September.

Figure 16: Ahuroa gas storage available and accessible for generation.



5. Generation offers reflected underlying costs and supply

5.1. There has been concern that reduced competition in the market may result in higher offer prices from generators to drive up prices. However, high offer prices may also reflect scarcity of fuel and be necessary for prudent management of fuel supply (this is applicable to both hydro and thermal fuels).

5.2. Part 13.5A of the Electricity Industry Participation Code 2010 (Code) requires that conduct in relation to generators' and ancillary service agents' offers are expected to be subject to competitive disciplines such that no party has significant market power, however, if one or more generators or ancillary service agents have significant power then any submission or revision of an offer must be consistent with the offer that the generator, acting rationally, would have made if no generator could exercise significant market power at the point of connection and trading period in which the offer relates.

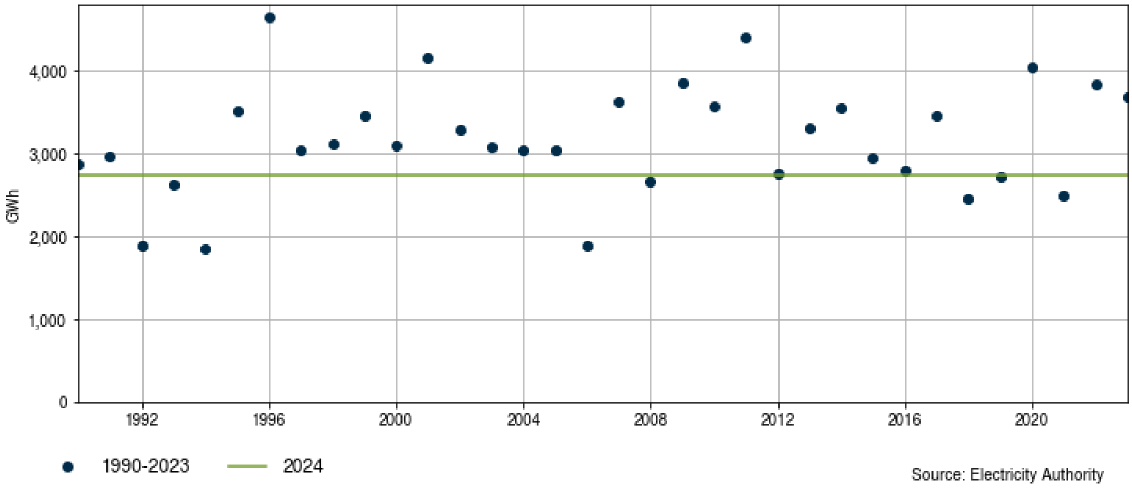
5.3. This chapter looks at generation offers from both hydro generators and thermal generators. Overall, we found that generation offers were consistent with the trading conduct rule and reflected underlying costs and supply.

Hydro generation offer prices increased due to falling storage of hydro lakes

5.4. This section examines how hydro offers for each major hydro scheme changed alongside its corresponding hydro storage. The section also includes storage simulation scenarios which illustrate the hydrology conditions generators were facing in mid-July.

5.5. On 1 January 2024 national hydro storage was 2,737GWh, which is 62% of full and 82% of mean. This is in the lower range of starting hydro positions in the last 24 years, as shown in Figure 17.

Figure 17: Starting storage position for each year 1990-24



5.6. All hydro locations except Manapōuri/Te Anau had declining storage for most of the first half of 2024. Most catchments only saw two significant inflow events, one in late January and another in mid-April.

5.7. By the end of June, Pūkaki and Takapō were below their 10th percentile – but by the end of July, Pūkaki, Taupō and Hawea were below their 10th percentiles, Takapō had recovered slightly and was just above its 10th percentile.

5.8. To understand how hydro offers were changing with lake storage, Figure 18-Figure 27 show the daily average adjusted offers and weekly total generation dispatch for the major hydro schemes alongside their lake storage. This is presented for May-September, to highlight the impact that high May demand and low inflows were having even before the onset of winter.

Meridian offers

5.9. Figure 18 shows how Meridian's Waitaki scheme offers changed over May-September as Pukaki storage declined.

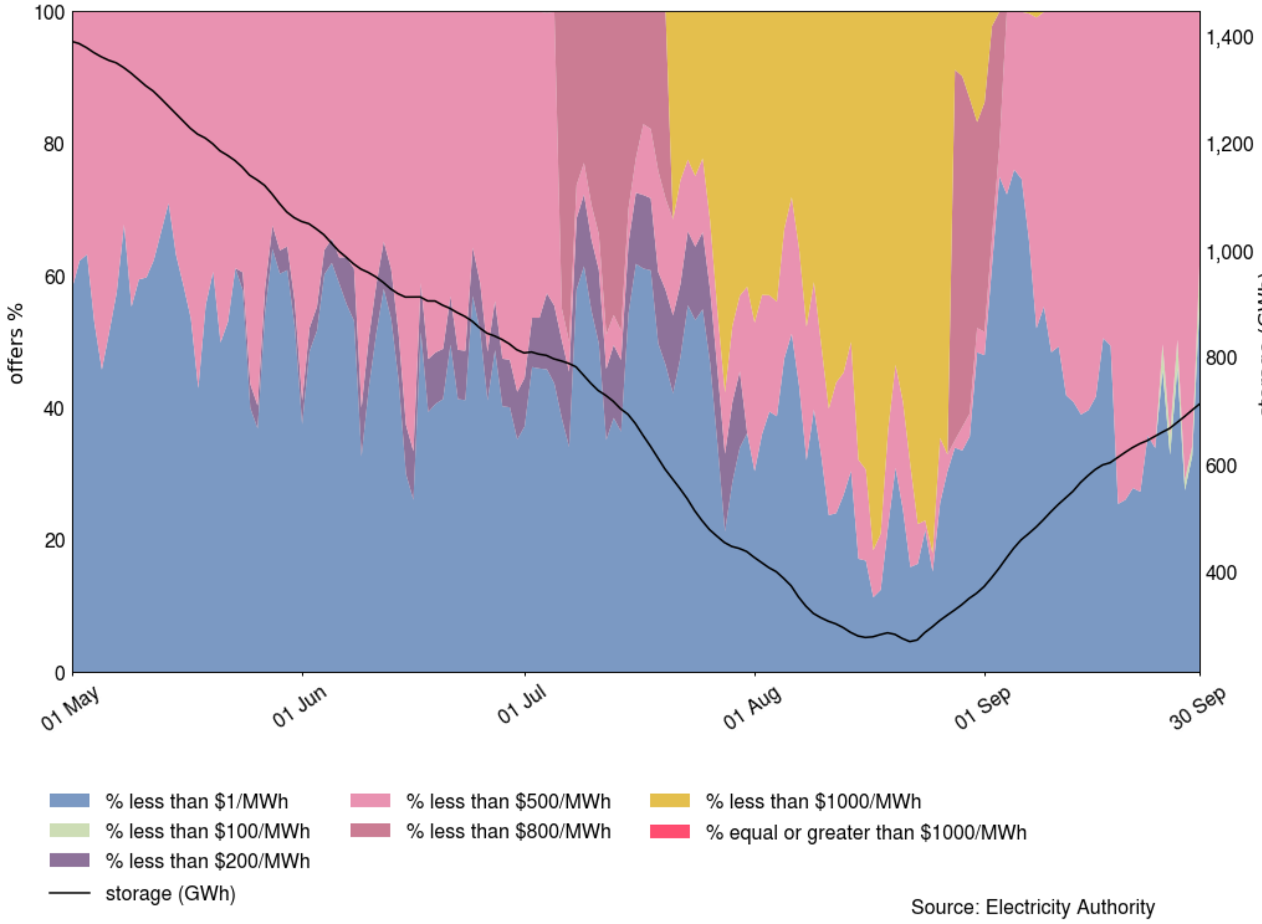
5.10. In early May storage at the Waitaki catchment was around 1,489GWh, which was close to mean for that time of year and 48% full (Pūkaki is full at 2,896GWh). During May, storage at Pūkaki decreased by 329GWh. As a result of this drawdown, Meridian decreased the percentage of offers priced below $1/MWh along the Waitaki chain, with an increased proportion of offers priced between $100-$200/MWh.

5.11. During May and June up to half of Waitaki's offers were priced between $200-$500/MWh as storage continued to decrease.

5.12. In early July, the amount of low-priced Waitaki generation increased. However, the top tranche of generation was priced up to between $500-$800/MWh, which is near the thermal generation short run marginal costs (SRMCs). As storage at Pūkaki continued to decrease over July this was later priced up to $800-$1,000/MWh, and the proportion of generation priced below $1/MWh fell from 40-60% in early July to less than 20% in mid-August.

5.13. This dramatic decline in low priced offers followed Pūkaki’s decline from 807GWh on 1 July to 436GWh by 31 July, a 370GWh drop which is 13% of its total storage. Meridian was pricing the majority of Pūkaki’s water to be near the generation of last resort in accordance with its water values, keeping it available in the market for security of supply. At this time, snow storage in the Waitaki catchment was also well below mean for 2024, which indicated that Pūkaki refill for 2025 could be below average, which further increased the value of the water in Pūkaki in July 2024.

Figure 18: Meridian Waitaki offers vs Pūkaki storage, May-September 2024



Source: Electricity Authority

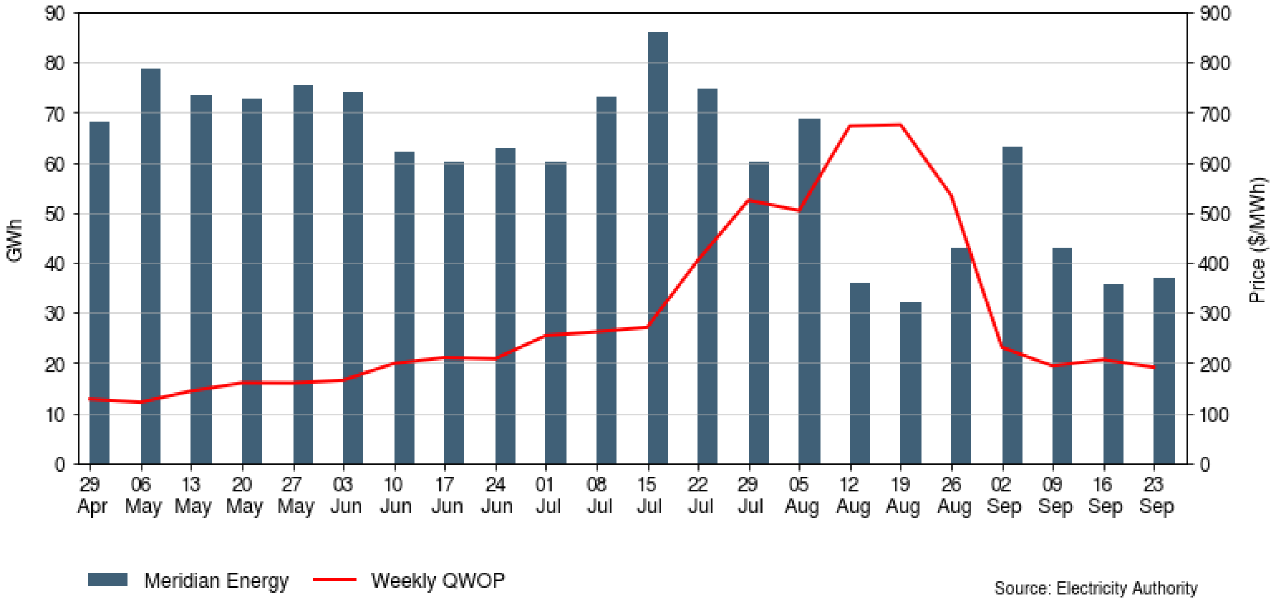
5.14. Storage in Pūkaki reached a minimum of 268GWh on 22 August, at which point inflows increased to exceed outflows and storage increased. Following heavy rainfall in early September Meridian offered over 70% of available capacity on the Waitaki scheme below $1/MWh. At this time the Waitaki scheme was primarily running on inflows from tributaries, and outflows from Pūkaki were low, allowing storage to increase significantly. However, as rainfall eased throughout September, a higher proportion of Waitaki's flow was originating from Pūkaki, and hydro offers changed to reflect this.

5.15. It is important to note that Meridian balances its low-priced generation across both hydro schemes and wind farms. Hence, on days in September when there was high generation from wind, Meridian decreased its amount of low-priced generation along the Waitaki. Meridian has noted that until Pūkaki recovers significantly, its hydrology position heading into winter 2025 remains a risk.

5.16. Figure 19 shows the total generation along the Waitaki scheme against the quantity-weighted-offer-price (QWOP) for the entire scheme. From mid-July, when storage at Pūkaki dipped below 600GWh, Meridian began increasing their price for generation along the Waitaki, and their dispatch along the Waitaki decreased from over 80GWh in the week beginning 15 July to 60GWh for the week 29 July. However, for the week starting 5 August, dispatch along the Waitaki increased back up to about 80GWh as dispatch increased due to low wind. In the subsequent weeks in August, as the QWOP along the Waitaki increased to

~$700/MWh, the total dispatch along the Waitaki fell to under 40GWh, which is half of what occurred in mid-July.

Figure 19: Total weekly hydro generation by Meridian in the Waitaki scheme, 29 April - 23 September



5.17. Figure 20 shows how Meridian's Manapōuri scheme offers over May-September as Manapōuri storage changed.

5.18. The Manapōuri reservoir has a narrow operating range and can fluctuate between its maximum and minimum range quickly in comparison to other locations. As a result, Meridian's Manapōuri offers follow its storage levels closely, with most of the generation offered below $1/MWh when lake levels are high.

5.19. Two generation units (128MW each) at Manapōuri were on outage, one is set to return in December 2024, and the other in September 2025. These outages limited flexibility at Manapōuri over winter 2024.

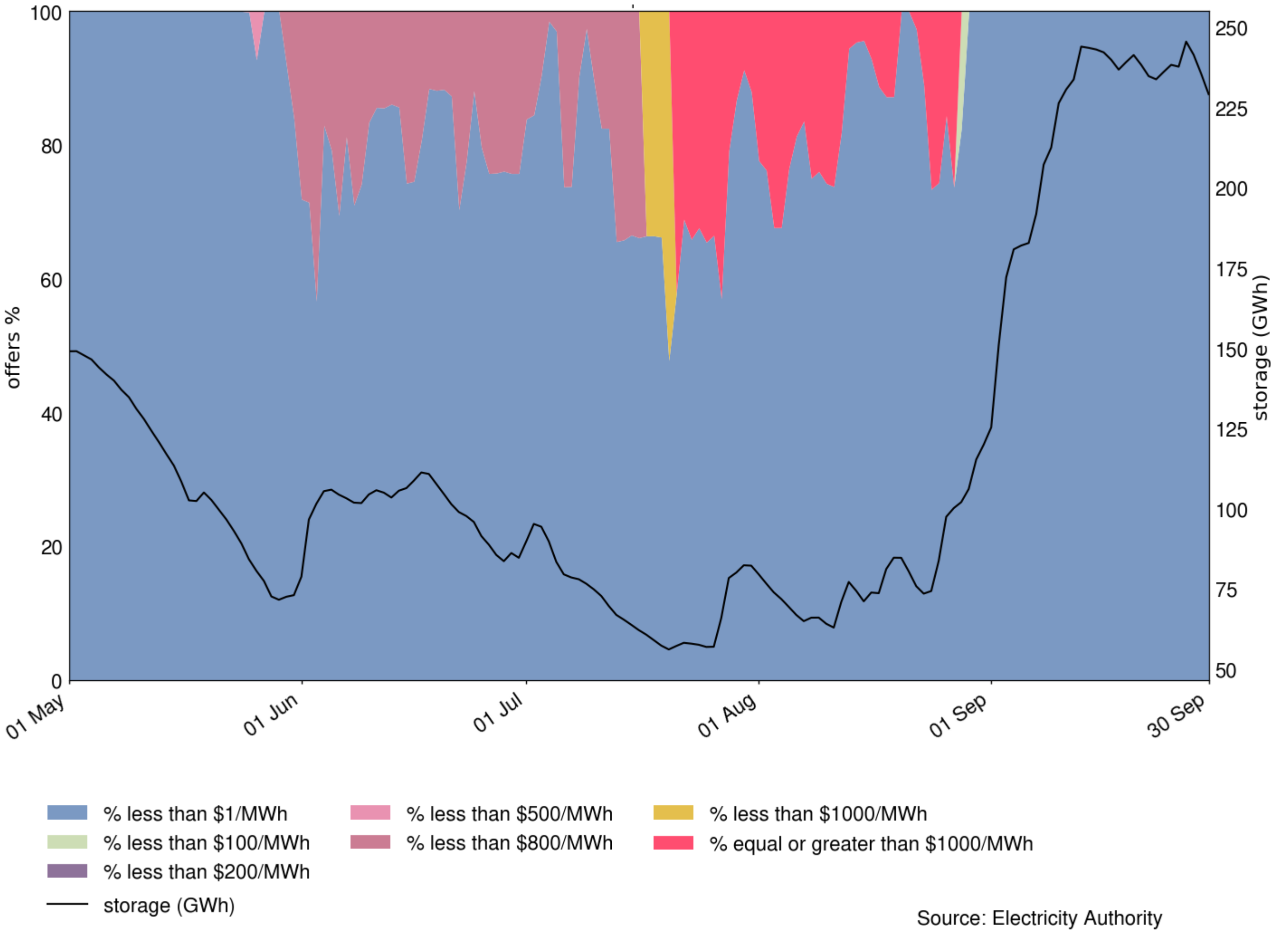
5.20. In May, Meridian had all generation at Manapōuri priced below $1/MWh, however, in early June between 10-40% of offers were priced between $800-$1,000/MWh as storage in the lake reached 80GWh (20% of full and 80% of historic mean).

5.21. In mid-July this high-priced tranche was briefly between $800-$1,000/MWh before quickly being priced up to greater than $1,000/MWh. Storage in Manapōuri reached a low of 53GWh on 26 July.

5.22. In mid-August, Meridian priced most of the energy at Manapōuri below $1/MWh, this was when Tiwai demand response was ramping towards 185MW, which allowed Meridian greater flexibility across their portfolio.

5.23. Due to record inflows in the Waiau catchment, significant spill occurred down the Waiau river beginning in early September.

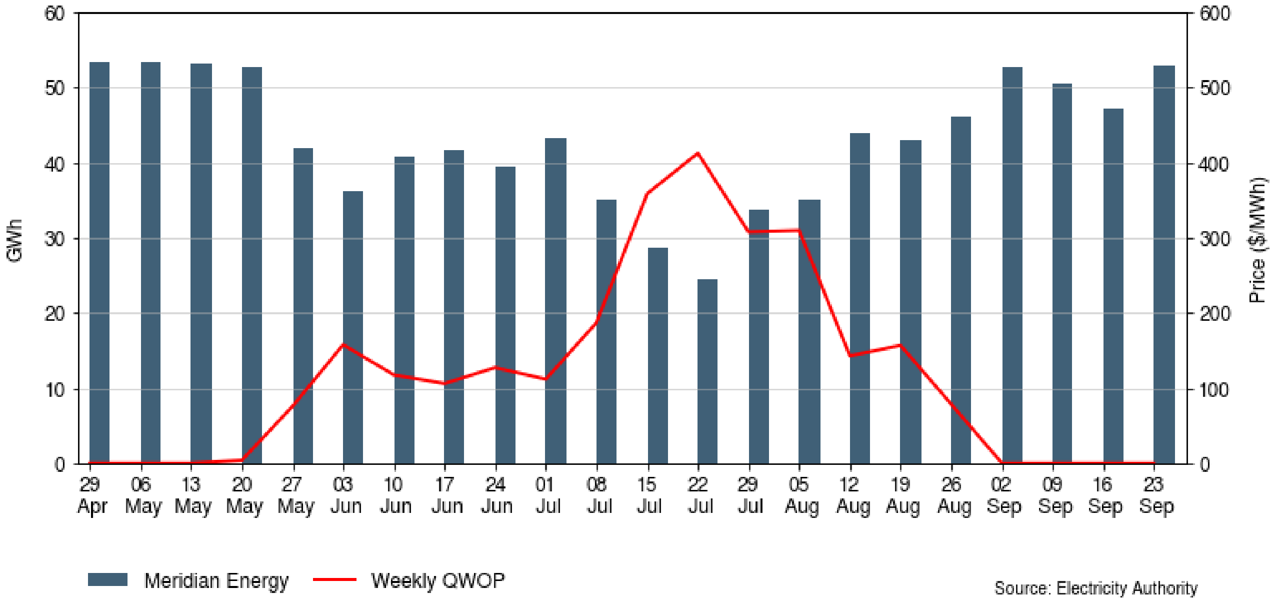
Figure 20: Meridian Manapōuri offers vs Manapōuri storage, May-September 2024



Source: Electricity Authority

5.24. Total weekly hydro generation and the weekly QWOP from Manapōuri over winter is shown in Figure 21. From mid-July onwards, as storage in Manapōuri declined below 100GWh, the QWOP at Manapōuri sharply increased from less than $150/MWh to over $400/MWh. Generation from the scheme also decreased until it hit a minimum of 24GWh for the week starting 22 July. However, in the following two weeks, Manapōuri hydro storage increased slightly, and the QWOP dropped to ~$300/MWh and the generation dispatched from the scheme increased.

Figure 21: Total weekly hydro generation by Meridian in the Manapōuri scheme, 29 April - 23 September



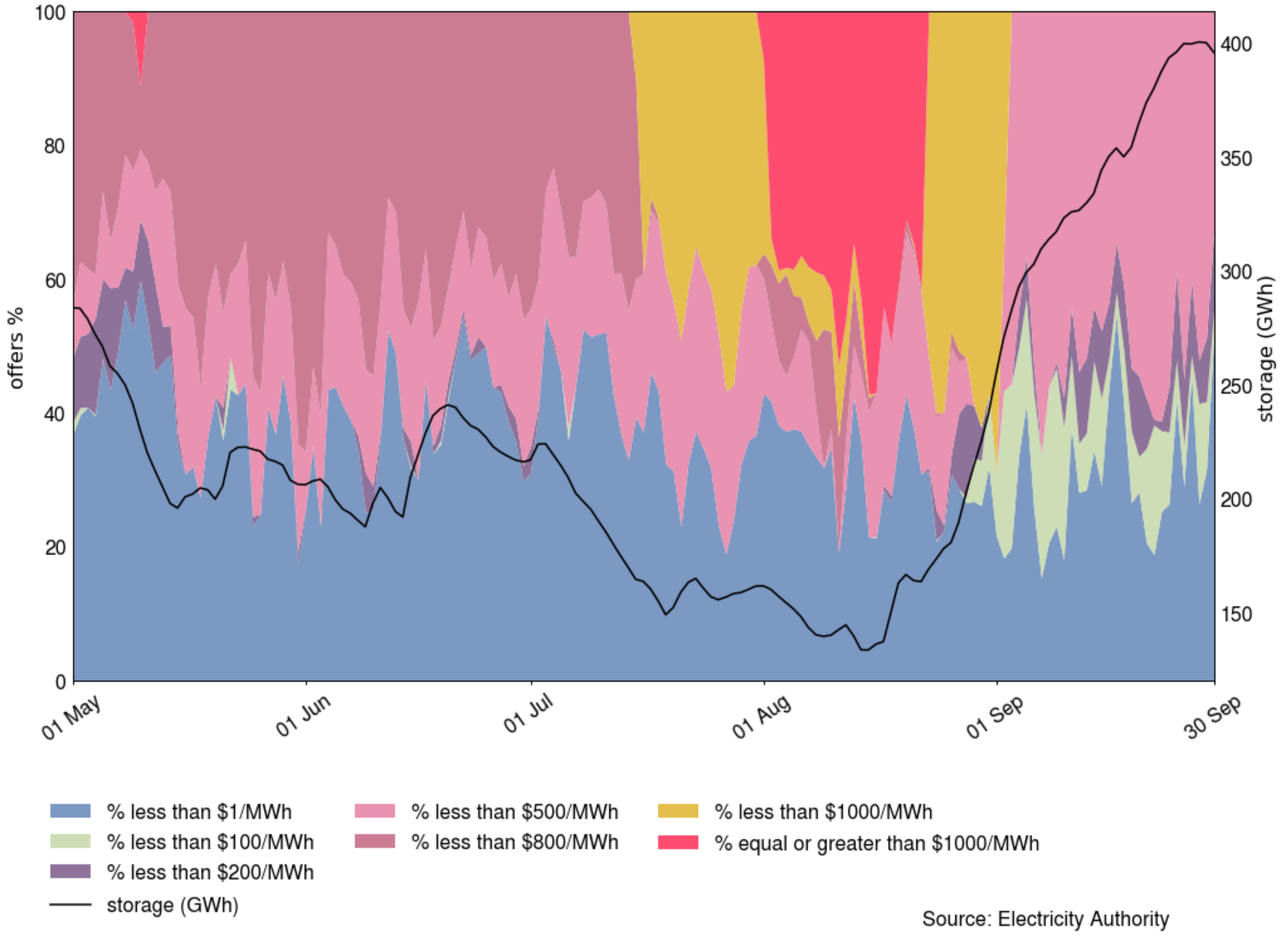
Mercury offers

5.25. Figure 22 shows Mercury's changes to Waikato scheme offers as Taupō storage changed. Mercury's Waikato scheme is the largest hydro scheme in the North Island but with smaller capacity than some of the southern hydro schemes. As such, its offers are more directly correlated with weekly demand patterns than overall storage levels. Mercury’s offers priced below $1/MWh dipped in weeks with high wind generation, as Mercury balances its low-priced generation between its wind and hydro stations.

5.26. Storage at Taupō was below average heading into winter 2024. May storage started off at 284GWh (which is 111% of mean and 42% full). Mercury had roughly 40% of offers priced below $1/MWh in May. As storage declined in May, both in Taupō and nationally, a greater proportion of offers were priced between $500-$800/MWh. In mid-July, the upper tranches of generation were priced between $800-$1,000/MWh, which was after losing 52GWh over two weeks.

5.27. In late July around 40% of offers were priced above $1,000/MWh as storage in Taupō reached 161GWh on 1 August. Once storage began increasing in mid-August, Mercury priced down their higher tranches of energy. While the energy priced below $1/MWh stayed relatively constant, the next lowest tranche then priced between $1-$100/MWh, where previously it had been mostly priced between $300-$500/MWh.

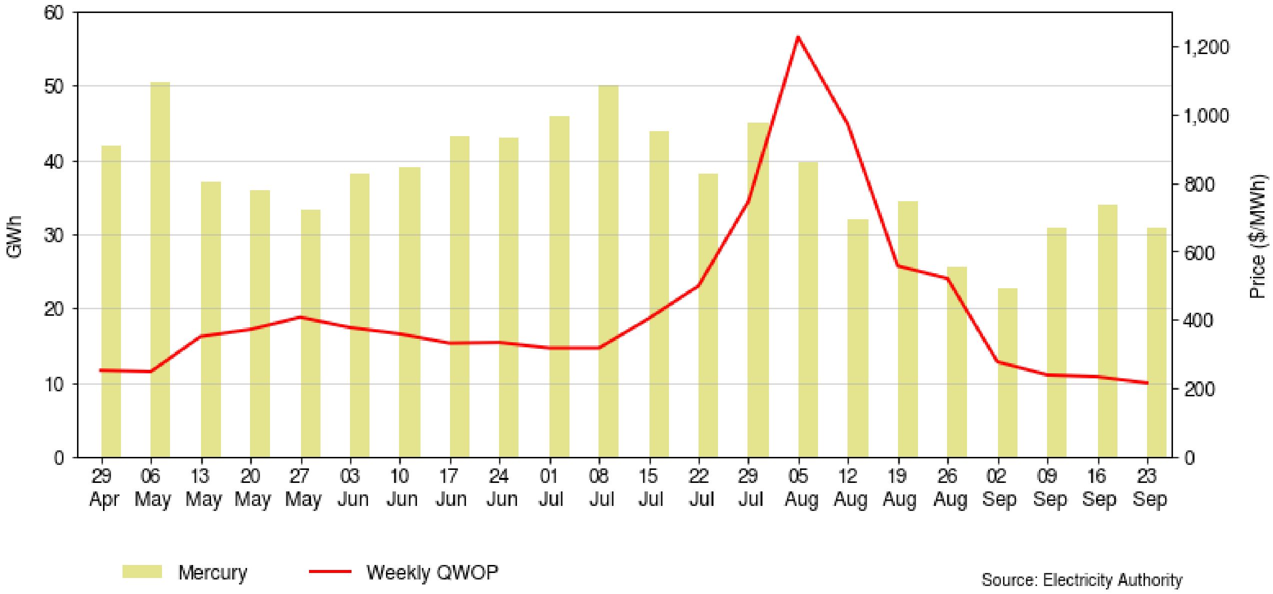
Figure 22: Mercury Waikato offers vs Taupō storage, May-September 2024



Source: Electricity Authority

5.28. Figure 23 shows the weekly total generation along the Waikato and the weekly QWOP for Waikato generation. As storage in the scheme continued to decline throughout July, and as national average prices began to increase, the QWOP along the Waikato also increased. The QWOP peaked in the week beginning August 5, but low wind meant that the total dispatch along the Waikato remained at 40GWh, but the following week, when wind generation increased, the total dispatch fell to 32GWh.

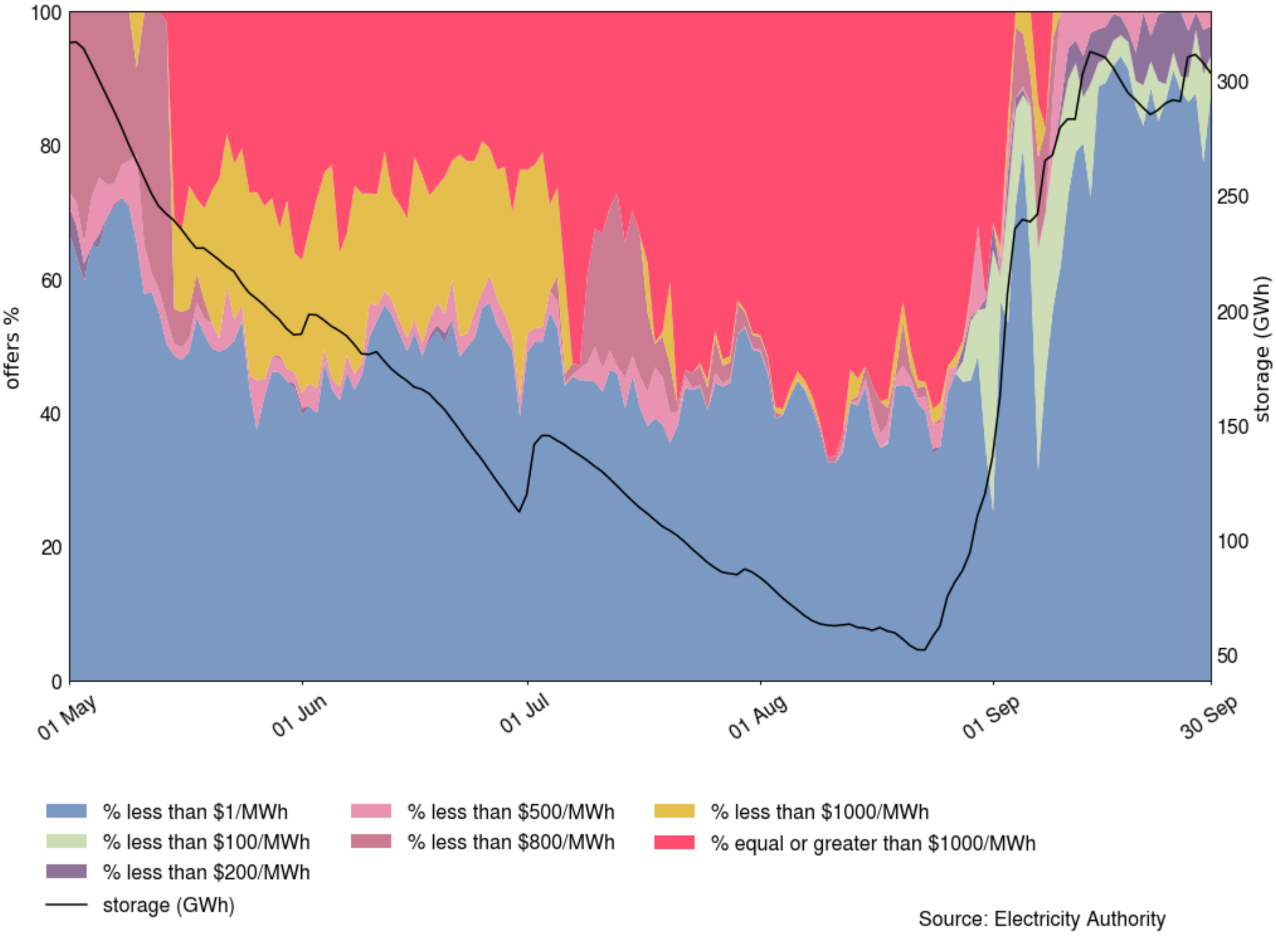
Figure 23: Total weekly hydro generation by Mercury along the Waikato, 29 April - 23 September



Source: Electricity Authority

Contact offers

Figure 24: Clutha offers vs Hawea storage May-September 2024



Source: Electricity Authority

5.29. In early May when Hawea storage was 316GWh (102% of mean and 75% of full) around 60% of Clutha offers were priced below $1/GWh with most of the remaining energy priced between $300-$500/MWh. However, after losing 127GWh over May, Contact priced 20-30% of Clutha offers above $1,000/MWh, another 10-20% was priced between $800-

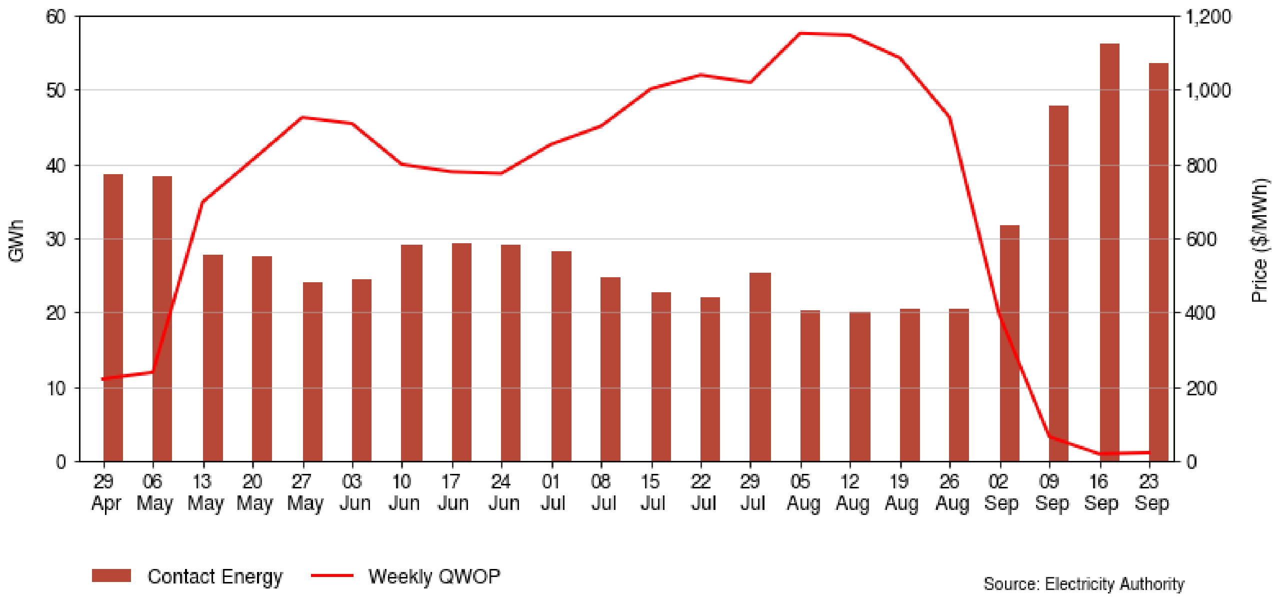
$1,000/MWh. These offer prices reflected the schemes reliance on outflows from Hawea, as run of river flows from Wakatipu and Wanaka were lower due to low rainfall.

5.30. After a small increase in Hawea storage, there were some offers priced between $300-$500/MWh in mid-July. However, as storage continued to decrease, there were essentially only two tranches of energy by early August, roughly 45% of energy was priced below $1/MWh, while the rest was priced above $1,000/MWh.

5.31. Storage reached a low of 51GWh on 23 August, which is 12% of full. As storage at Hawea rapidly increased, Contact was able to run the Clutha scheme while using minimum Hawea storage, as the run of river flows from tributaries were sufficient.

5.32. Throughout September roughly 80-90% of offers were priced below $1/MWh, with some remaining energy priced high. These offers are being analysed further in the trading conduct monitoring.

Figure 25: Total weekly hydro generation by Contact in the Clutha scheme, 29 April - 23 September



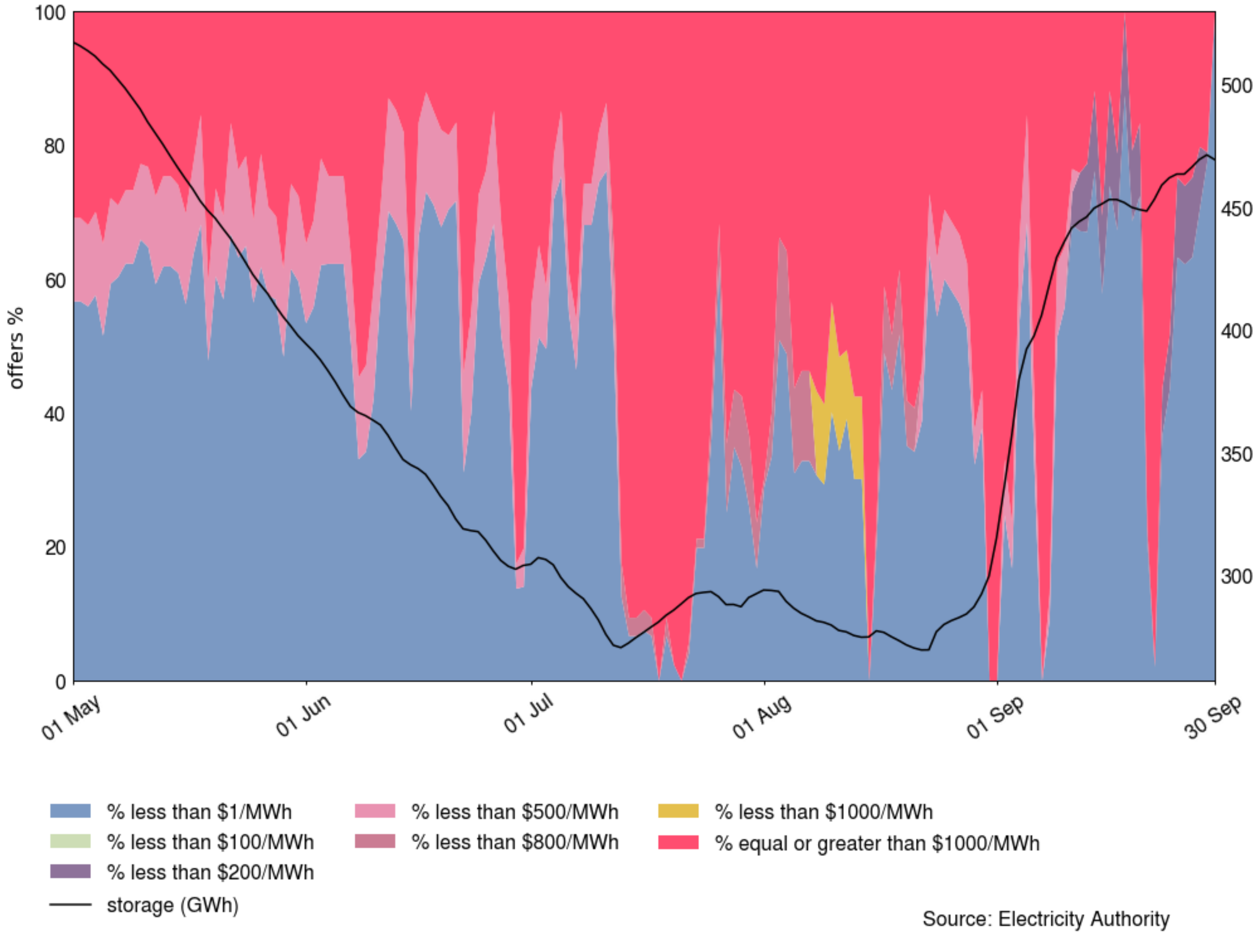
5.33. Figure 25 shows the relationship between total weekly dispatch along the Clutha and the Clutha weekly QWOP. Contact increased the Clutha's QWOP from mid-May, which was when TCC turned back on, and dispatch along the Clutha fell. During this time, Clutha flows were being majority fed by Hawea outflows, and the offer prices increased to reflect this.

5.34. The Clutha's QWOP peaked in early August which was when dispatch reached a minimum of 20GWh. In late August as Hawea storage rapidly increased, and Contact was able to keep outflows from Hawea to a minimum, the QWOP dropped significantly.

Genesis offers

5.35. Takapō is New Zealand's second largest hydro lake, however, the lake has been below average since November 2023. Water from Takapō flows through the Takapō hydro plants and into Pūkaki, where the water is later used to feed Meridian's Waitaki scheme.

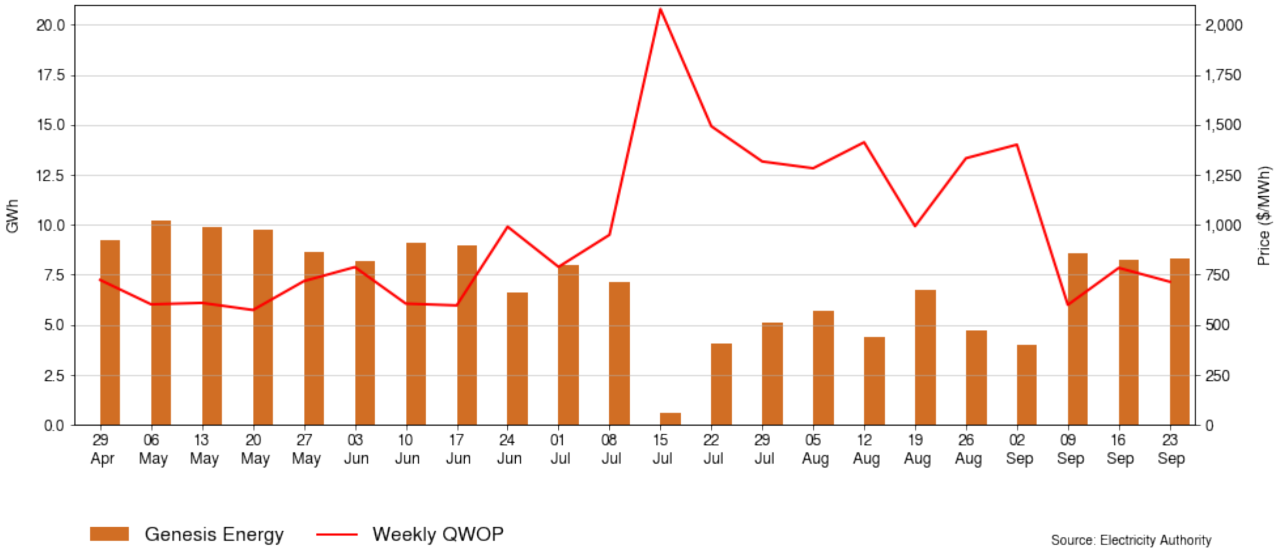
Figure 26: Takapō scheme offers vs Takapō storage May-September 2024



Source: Electricity Authority

5.36. In early May, Takapō had 517GWh of storage, which is 83% of mean and 47% of full. Genesis had roughly 60% of Takapō offers priced below $1/MWh, with another 10% priced between $200-$500/MWh, and another 30% priced above $1,000/MWh. Over May, Takapō lost 119GWh and over June it lost another 90GWh. Takapō reached its minimum of 272GWh on 14 July, which is 25% of full, during this time Genesis priced most water in Takapō above $1,000/MWh, and Genesis turned on its third Rankine. Low priced offers returned around a week later as storage stabilised. Once storage began increasing in late August close to 60% of weekday offers were priced below $1/MWh.

Figure 27: Total weekly hydro generation by Genesis in the Takapō scheme, 29 April - 23 September



5.37. Figure 27 shows the total weekly generation from the Takapō scheme and the schemes weekly QWOP. The QWOP peaked in mid-July, when storage at Takapō dropped below 300GWh, and Genesis brought the third Rankine online. As storage recovered throughout late July, the QWOP decreased slightly, and weekly dispatch remined mostly below 7.5GWh a week. As storage recovered in late August and September, the QWOP fell, and the total generation dispatched increased.

Table 1: Correlations between QWOP and storage

July-September	Pūkaki	Waikato	Clutha	Takapō	Manapōuri
Correlation between QWOP and storage	-0.90	-0.98	-0.91	-0.61	-0.90

5.38. Table 1 shows the correlations between the QWOP and storage at each scheme between July-September 2024. There was a strong negative correlation at all schemes, except Takapō, indicating that increased offer prices were reyelated to declining storage. The correlation at Takapō was moderate. Genesis priced the majority of Takapō generation above $1,000/MWh, over a period where storage slightly increased. Genesis continued to highly price weekend generation at Takapō, even after Takapō storage had increased. However, this was due to Genesis needing to preserve water due to a resource consent conditions. Takapō's minimum lake level increases from 701.8 meters above sea level (masl) to 704.1 masl on 1 October[7]. This impacted offer behaviour in August and September (particularly given the low inflows between May and August) as Genesis needed to ensure lake levels were high enough to not risk breaching conditions when the step change occurred on 1 October.

5.39. In summary, for all the major schemes with associated storage, generators increased the cost of generation as storage decreased. Total dispatch from each scheme tended to decrease as the QWOP for each scheme increased. Dispatch from the Waitaki scheme increased during the week starting 5 August when wind generation was low. These were the $800/MWh prices often seen that week. Once wind generation increased the following week, and dispatch increased at Manapōuri, prices fell to $300-$500/MWh range. After significant inflows occurred across all schemes the QWOP for each decreased, and the spot price also dropped.

Projected storage trajectories

5.40. To further understand the hydro offer changes in autumn and winter 2024, we estimated some simple long and short-term projected storage scenarios initialised in mid-July for the major hydro schemes.

5.41. These simulations allow us to understand what the generators who operate the major hydro schemes were likely considering when they were changing their hydro offers in July, given the uncertainty about future inflows.

5.42. Throughout the first half of 2024 total lake inflows were relatively close to mean. By 1 July 2024, the accumulative inflows across all lakes for the year was 6,698GWh while the mean for that time of year would be 7,172GWh and the median would be 5,924GWh.

5.43. However, the hydro storage was below average at the beginning of 2024 which, coupled with high drawdown due to high autumn demand and low gas availability, meant that by 21 July total national hydro storage was at 1,817GWh (57% of mean and 40% of full).

In the short-term simulations, several lakes reached the bottom of their operating range

5.44. Simulations for short-term storage projections are shown in Figure 28-Figure 32 for Taupō, Pūkaki, Hawea, Takapō and Manapōuri.

5.45. These simulations take the average drawdown from the previous 14 days and simulate that draw down continuing through to 31 August. The results of these short-term simulations are summarised in Table 2.

Figure 28: Simulated hydro decline for Taupō from 21 July to 31 August, (no contingent storage available)

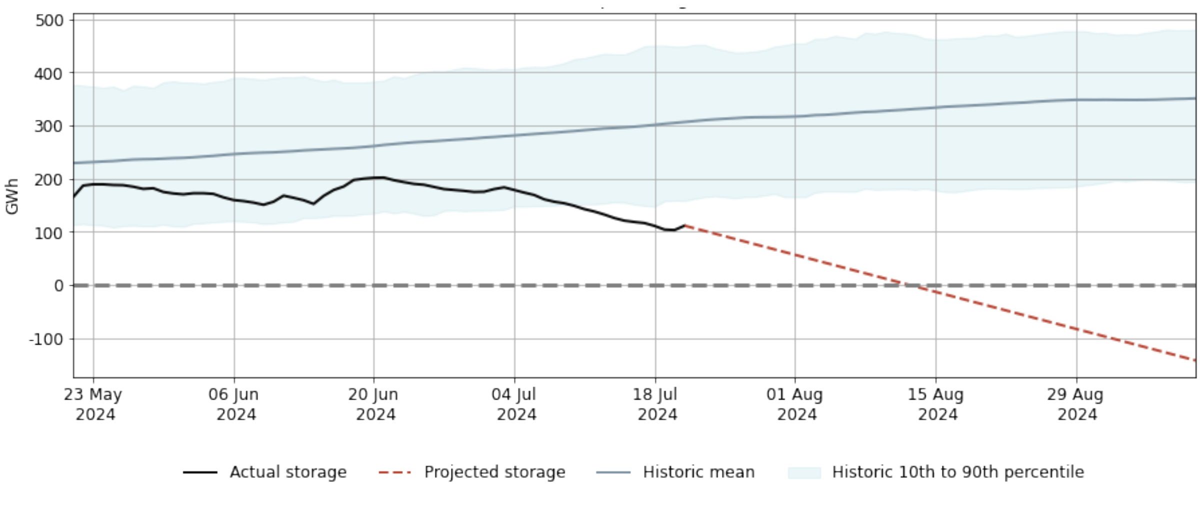


Figure 29: Simulated hydro decline for Pūkaki from 21 July to 31 August, including contingent storage

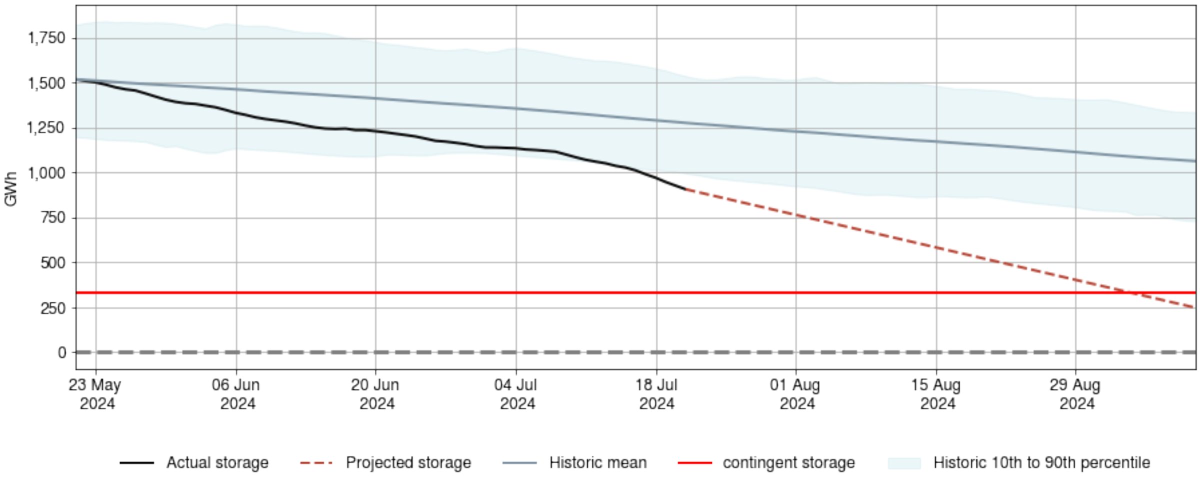


Figure 30: Simulated hydro decline for Hawea from 21 July to 31 August, including contingent storage

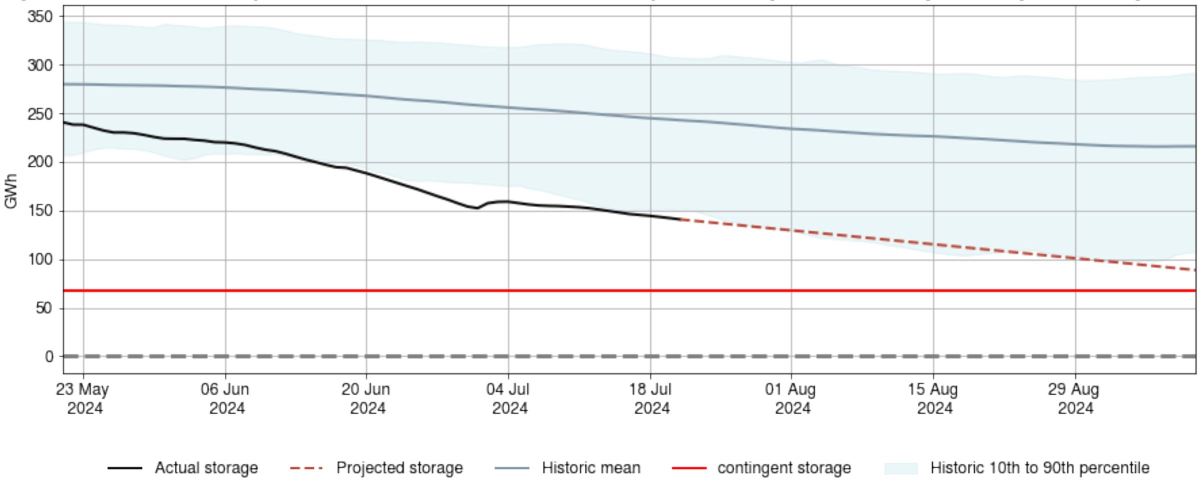


Figure 31: Simulated hydro decline for Takapō from 21 July to 31 August, no contingent storage available

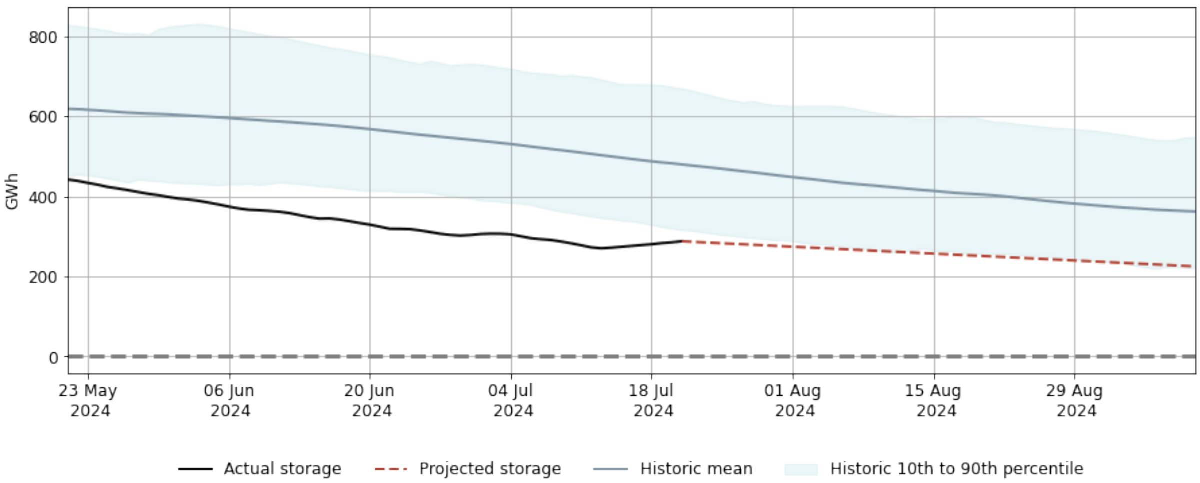


Figure 32: Simulated hydro decline for Manapōuri from 21 July to 31 August, no contingent storage

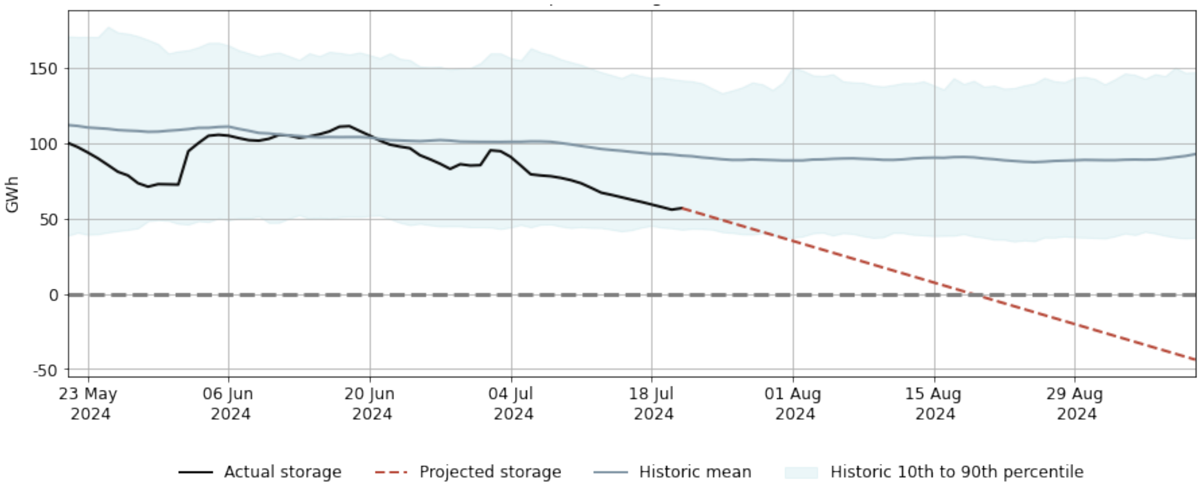


Table 2: Summary of short-term storage simulations

Lake	Minimum simulated storage (GWh) [contingent storage*]	Date reached	Maximum storage (GWh) (including contingent storage)
Taupō	0	13 August	662
Pūkaki	247 [330*]	31 August	2,896
Hawea	88 [67*]	31 August	418
Takapō	224	31 August	1,082
Manapōuri	0	19 August	417

5.46. These short-term decline simulations show that if the drawdown trajectories experienced between 7-20 July had continued through to the end of August, Lakes Taupō and Manapōuri would have reached their minimum operating range. Pūkaki would also have been below its controlled storage range and needed to use contingent storage.

5.47. The alert status curve in early August was 662GWh, meaning that controlled storage across all lakes would need to be at (or below) 265GWh for contingent storage to be available. This means that some lakes could have reached 0GWh remaining in controlled storage, including Pūkaki, without having access to contingent storage.

5.48. In these simulations, Taupō would have run out first on 13 August, however, the remaining lakes would have had a combined controlled storage of 589GWh, and 407GWh of contingent storage. Then on 19 August, Manapōuri's simulated levels reached zero, there would have been 487GWh of controlled storage remaining. Since the access to contingent storage is coupled between all lakes, there are scenarios where multiple lakes would be at their minimum operating range, but the contingent storage barrier would not be crossed at a national level.

5.49. In the system operator's update to the electricity risk curves on 22 July 2024, they showed that the storage in the previous two weeks had been tracking in the lower range on their simulated storage trajectories (SSTs) and towards the worst-case SST. On 19 August the

SO increased the alert status curve threshold to be 1,032GWh, allowing generators to access their contingent storage earlier if storage continued to fall.

Long term simulations show that the impacts of low hydro storage in 2024 could still be felt in winter 2025

5.50. Figure 33 shows the national storage on 21 July, when hydro storage reached 1,817GWh. From this point there are four storage projections scenarios:

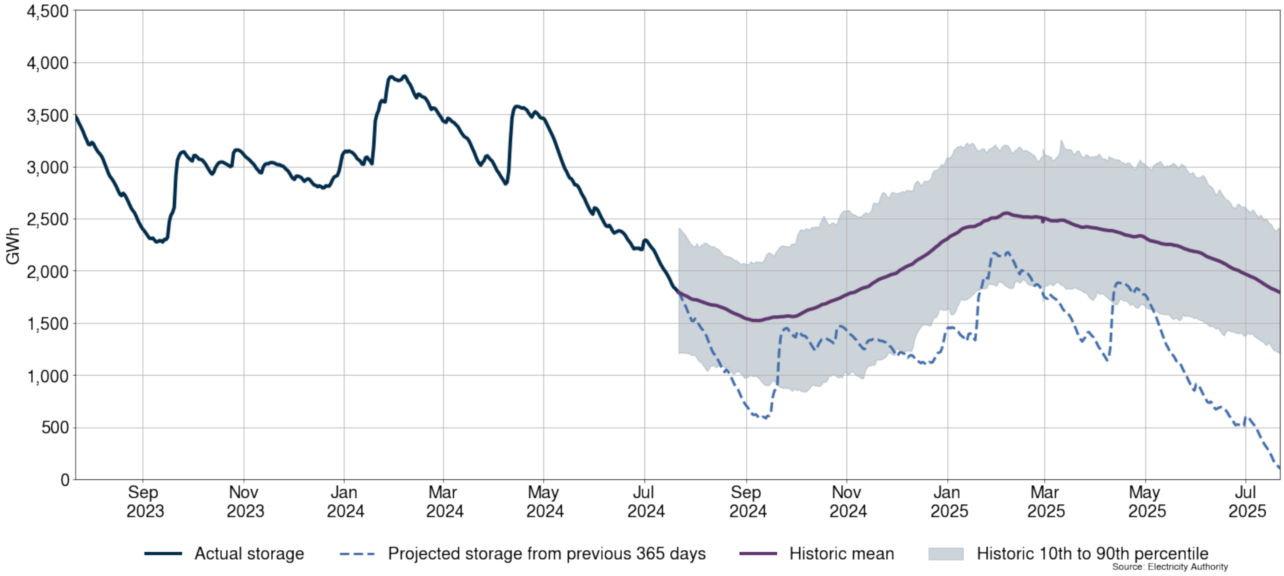
(i) The first is a simulation taking the inflow/outflow sequence from the last 365 days and projecting it forward, this simulates what national hydro storage could look it if he 2024/25 year was identical to the 2023/24 year. All analysis in this section includes contingent storage.

(ii) The next simulation takes the mean storage sequence from all historical data and projects it forward from 22 July.

(iii) The third simulation shows what storage over 2024-25 would look like if storage tracked along the bottom 10th percentile of historic sequences.

(iv) The fourth simulation projects storage in 2024-25 if it tracked along the 90th percentile of historic hydro sequences.

Figure 33: Projected national storage from 22 July 2024 for the next 365 days (including contingent storage)



5.51. The results of these four simulations are shown in Table 3 and reveal several insights. Firstly, in mid-August hydro storage was so low that even if hydro storage tracked at around mean from 16 August onwards, the national storage would only recover to 2,500GWh, which is 56% full heading into winter 2025. Even if storage had suddenly begun to track at the 90th percentile, storage would only have reached ~3,000GWh which is only 82% of mean.

5.52. Essentially, national storage reached such low levels in July, that even if storage had begun to track at the 90th percentile, total storage wouldn't have recovered to mean levels by February next year.

5.53. These simulations show that offer changes were made in a hydrological environment where storage was so low, that even if even storage began changing in a way which aligned with the mean, the maximum storage available in the next 12 months would only be 57% full.

Table 3: Long-term simulation summary

Simulation	Minimum storage in next 365 days	Month minimum is reached	Maximum storage in next 365 days	Month maximum is reached	Maximum storage as % of full	Maximum storage as % of mean
2023-24 rolled over	102	July 2024	2,100	February 2025	47.6	59.5
Mean	1,550	September 2024	2,520	February 2025	57.1	70.1
10th percentile	1,300	October 2024	1,920	February 2025	43.5	53.4
90th percentile	2,140	September 2024	3,190	February 2025	72.3	88.7

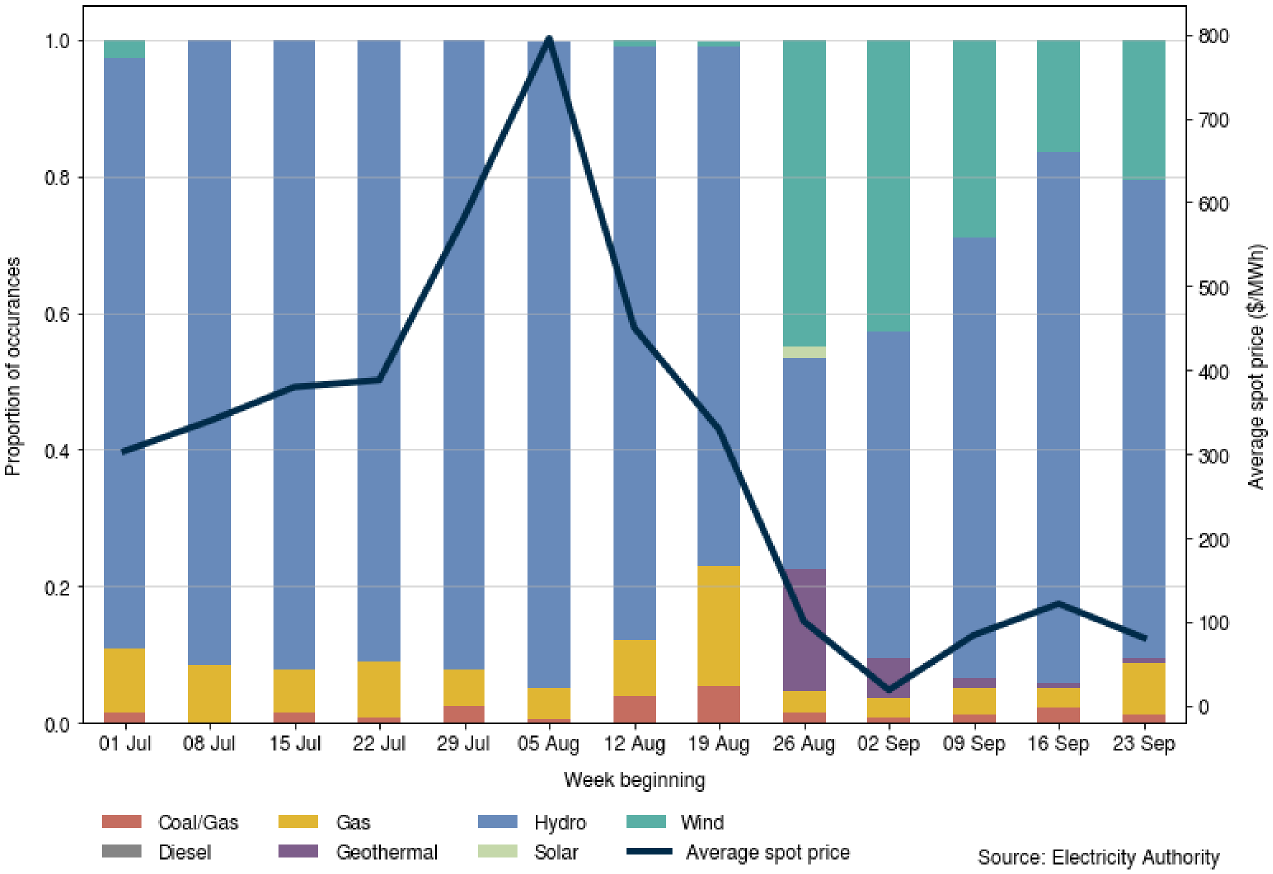
5.54. In summary, both the simple long and short-term simulations of hydro storage help explain why several hydro operators were pricing their water above thermal SRMCs during winter 2024. Several lakes were tracking along storage trajectories which, if they had continued, would have caused them to cross their minimum operating ranges. Additionally, there was no guarantee that once Pūkaki or Hawea reached their minimum level, generators would have access to contingent storage. Also, storage reached such low levels in July that even if storage suddenly began tracking at the 90th percentile inflow/outflow sequence, storage would still not reach the mean level by the following February, which could see lakes in a similar position for winter 2025.

During the highest spot prices, expensive fuels were often marginal

5.55. Figure 34 shows the percentage of each generation type that was marginal over the winter months. During the period of high prices over July and August, hydro generators were often marginal. This was followed by gas generation, particularly in mid-August.

5.56. From the last week of August, decreased demand, increased fuel and increased wind caused wind and geothermal to be marginal more often. Wind and geothermal are both price takers, which indicates low prices (usually overnight) However, hydro generation continued to be the marginal generator most often.

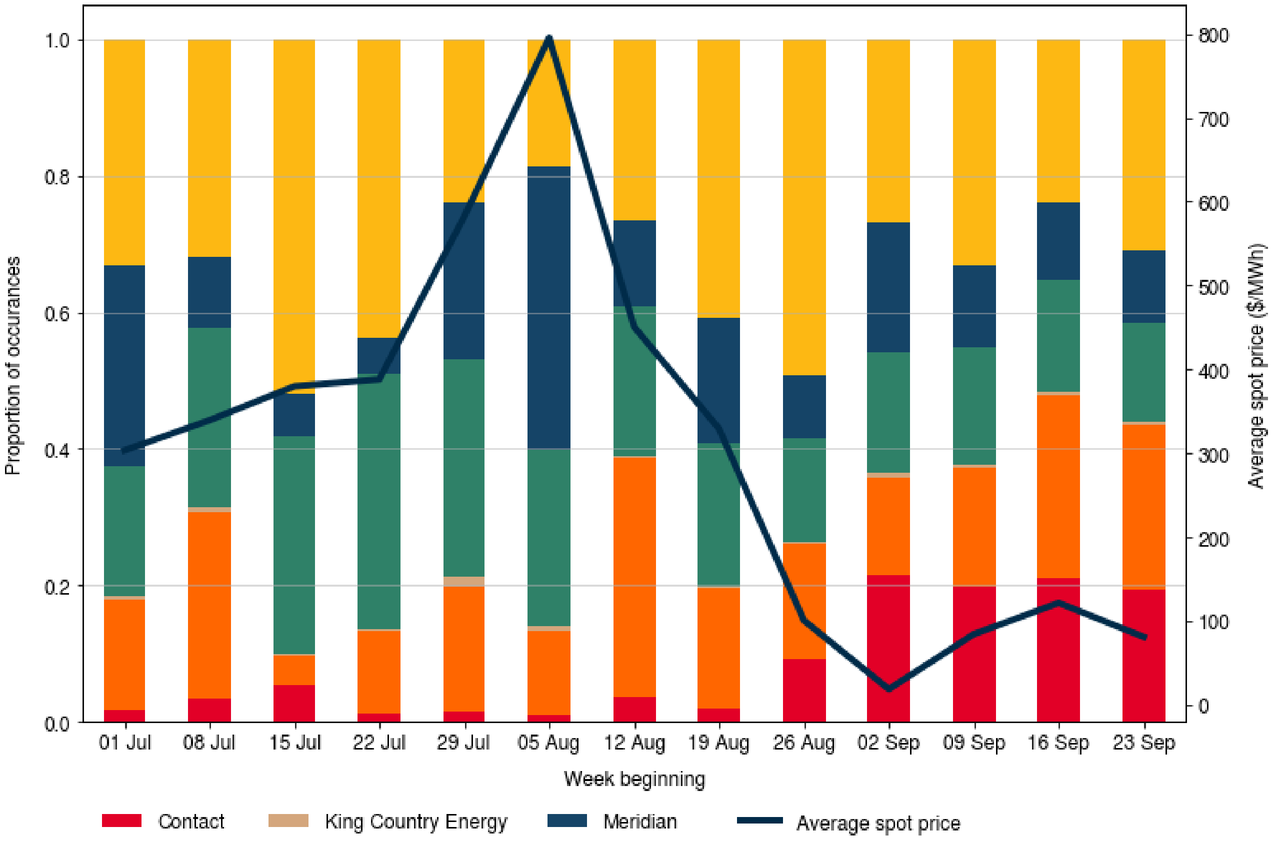
Figure 34: Proportion of marginal generation each week by generation type



Source: Electricity Authority

(a) Figure 35 shows the proportion of marginal hydro generation by participant. In July, North Island hydro owned by Manawa, Mercury or Genesis was setting the price most often. However, in the week beginning 5 August, which was when prices reached over $800/MWh, Meridian's South Island hydro generation was marginal more often. This was after Meridian had priced up its tranches along the Waitaki and at Pūkaki to help preserve the rapidly declining lake levels at Pūkaki and Manapōuri. High inflows particularly along Clutha increased the percentage of time Contact was marginal in September.

Figure 35: Proportion of hydro marginal generators each week by participant



Source: Electricity Authority

Thermal offers reflected both costs and shortage of available fuel

5.57. We requested additional information from generators with thermal generation, Genesis, Contact and Nova, on their fuel supply and costs using our powers in section 46 (s46) of the Act. This included coal, gas and diesel. We also asked about biomass, but this was not used this winter.

5.58. The following analysis uses the s46 data and other data sources to assess the cost and availability of thermal fuels and compares the short run marginal cost (SRMC) of each plant with generation offers to determine if thermal offers during winter 2024 were consistent with the underlying conditions.

5.59. All three generators buy gas under contract and from the spot market for gas. The spot market price for gas can fluctuate day to day, based on current conditions, as gas supply and gas consumption need to be broadly balanced to maintain gas pipe pressure. However, generators buy most of their gas under contract at prices that may be negotiated years in advance to the actual date of consumption.

5.60. Methanex produces methanol for export and is the largest single user of natural gas in New Zealand. Tight gas supply conditions in August limited the availability of gas for electricity generation. Genesis and Contact signed gas supply deals. The deals meant Methanex shutdown production and on-sold its gas at a price they expected to exceed the lost margin from lost methanol production.[8] This deal began on 13 August and resulted in a sharp reduction in the gas spot price.

Genesis

5.61. Genesis operates the Huntly power station which has three coal/gas fired Rankine units (Huntly units 1, 2 and 4, 250MW each), one combined cycle gas turbine (Huntly unit 5, 403MW) and one open cycle gas turbine (Huntly unit 6, 50MW), which can also be diesel-fuelled.

5.62. Genesis has a 46% stake in the Kupe joint venture.

5.63. Genesis has a coal stockpile which it can use to power the three Rankine units instead of gas. Most of the coal in this stockpile is sourced from Indonesia and imported into New Zealand. This coal has been important for security of supply when other fuels are in short supply, as seen this year.

5.64. Genesis also has a small amount of diesel storage, which it can use to fuel Huntly 6. Diesel has a much higher cost compared to gas and coal.

Net gas supply

5.65. Gas consumption at Huntly Power Station is a representation of the amount of gas used for generation. Between July and mid-August consumption at Huntly was between 40 and 50TJ/day. This increased to around 60TJ/day as Methanex turned down its production to sell gas to Genesis and Contact.

5.66. For context, running Huntly 5 (E3P) at full capacity would use around 70TJ/day. This is Genesis's largest and most efficient electricity generator at Huntly. Except for a brief period in late August, the amount of gas Genesis received during this period has not been enough gas run both Huntly 5 at full capacity and supply its customer base with gas.

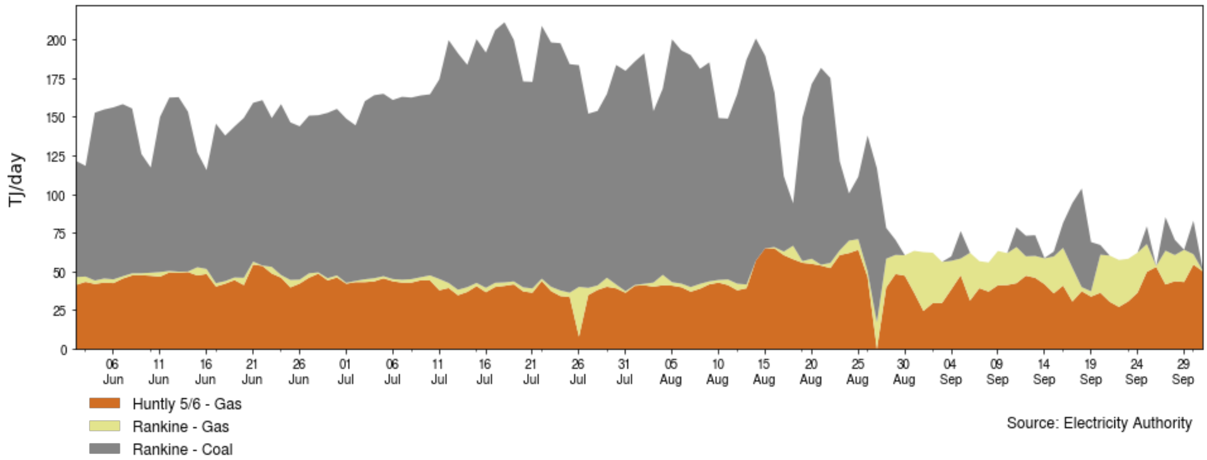
Generation from gas and coal

5.67. Figure 36 shows an estimate of the amount of gas and coal used at Huntly power station. In July and early August, the Rankines were predominantly running on coal, due to the short supply of gas. This continued until late August when increased gas supply from the Methanex contract meant it was more economical to run the Rankines on gas. Diesel usage at Huntly 6 is not shown due to scale.

5.68. Gas usage in Huntly 5 also increased from 13 August after Methanex shutdown. Kupe outages on 27 August and from 17-20 September temporarily reduced gas usage at Huntly.

[8] https://www.methanex.com/news/release/methanex-corporation-to-temporarily-idle-new-zealand-operations-to-assist-in-improving-energy-balances/

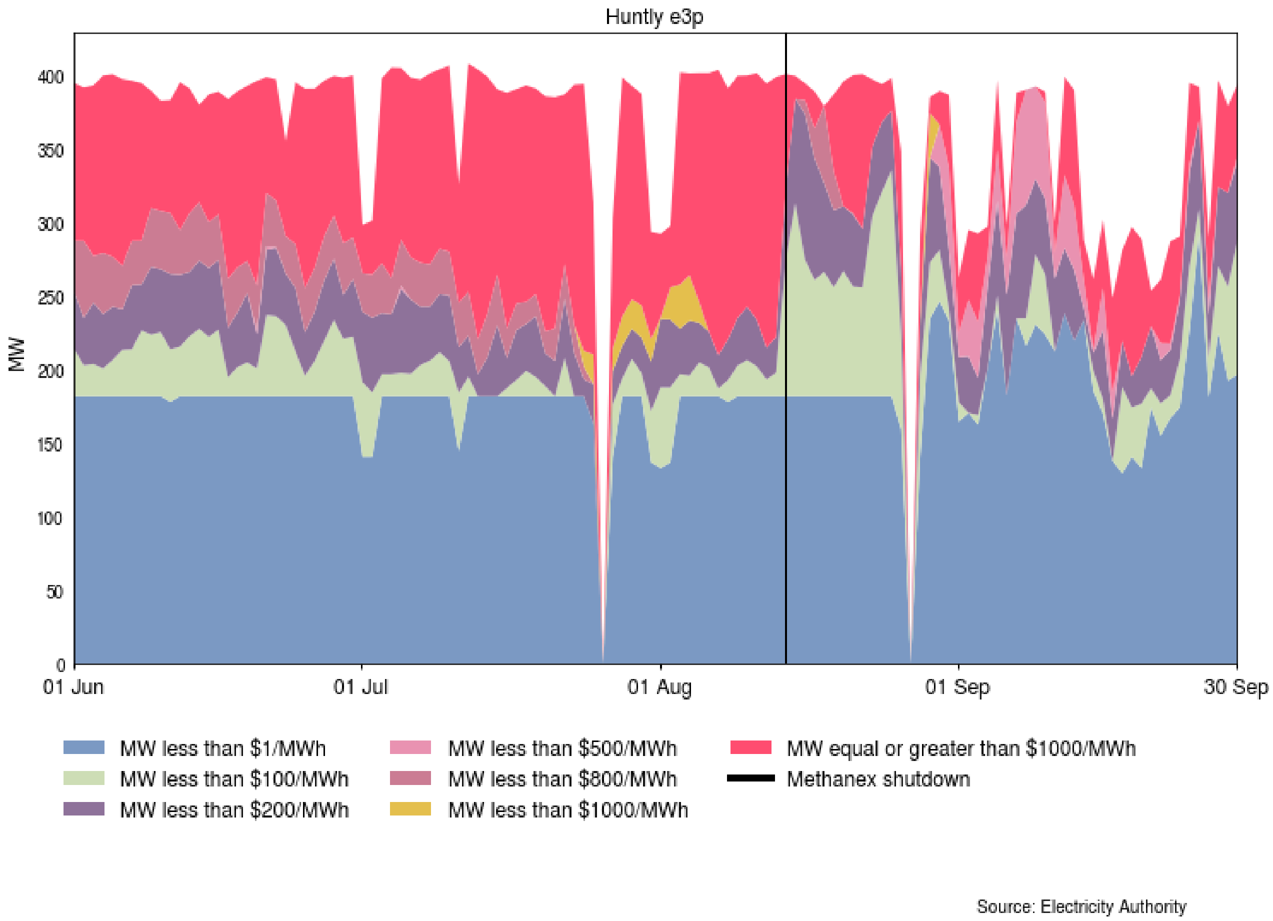
Figure 36: Huntly generation from gas and coal estimates



Huntly 5 (E3P) offer behaviour

5.69. Figure 37 shows average daily offer tranches at Huntly 5 since the start of June. Huntly 5's capacity is 403MW, so total offers around 400MW indicate that the full capacity was offered for most of the day, while it dropped to 300MW at time due to not running at night when demand was lower. The two occasions offers dropped to 0MW were when Huntly 5 was on outage.

Figure 37: Offer tranches at Huntly 5 since June 2024



5.70. For most of July to September, around 182MW of generation was offered at or below $1/MWh. This ensured that at least the minimum required generation was dispatched to keep Huntly 5 running as baseload over the winter months. There was also a proportion of generation offered above $1/MWh and below $200/MWh, particularly during the peak periods when Huntly 5's generation output would be increased to help meet demand.

5.71. Very little generation was offered between $200/MWh and $500/MWh, which was around the range of the spot gas price, or the marginal cost if Genesis needed to buy additional gas on the spot market, at least up until late August. Note that had Genesis tried to purchase a large quantity of gas on the spot market for gas, it could have substantially increased the spot price for gas due to low supply. This was already occurring in early August when the increase in spot traded gas volumes increased the spot gas price by over $10/GJ.

5.72. Genesis then had two tranches which were sitting above the price of most hydro generation. Some of this generation was offered between $500 and $800/MWh through June and July, and then in early August when hydro offers increased this was priced between $800 and $1,000/MWh. Tranche 5 was offered above $1,000/MWh. The amount of capacity offered in these tranches was highest overnight, when demand is low, ensuring more gas could be used during peak times.

5.73. Genesis has stated that capacity offered at these highest prices [above $800/MWh] was due to a shortage of gas, which prevented it from running Huntly 5 at, or close to, its full capacity for significant periods of time. Capacity at these high prices was unlikely to be dispatched as they were priced above hydro generation offers, however, it offered capacity to the market in case it was needed for a short period.

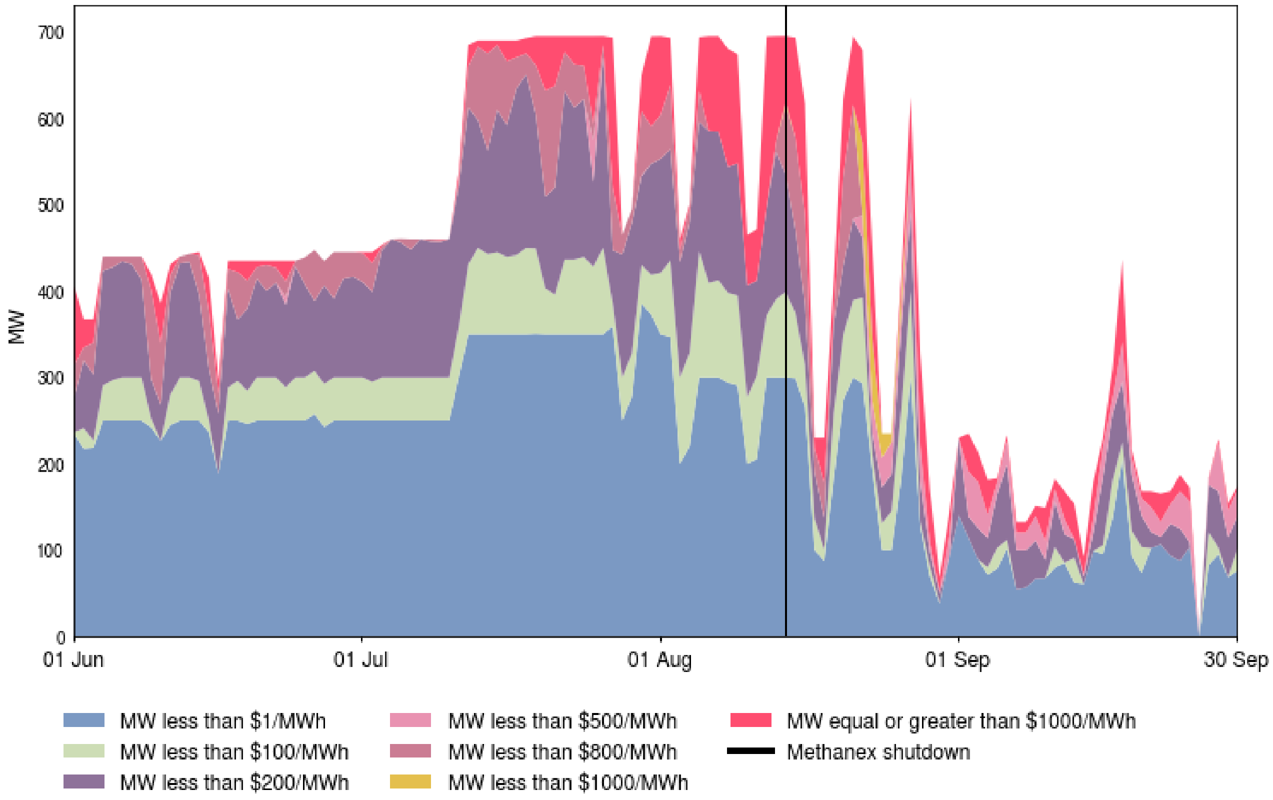
5.74. In early August there were times when generation from Meridian's highest tranche was dispatched. Had Genesis not increased tranche 4 prices this generation would have been dispatched instead. However, this would have required Genesis to either buy additional gas (if available), which would have increased the gas spot price, or reduce generation offered at tranche 3 or below, at another time. It is likely this would have resulted in Meridian's highest tranche still being dispatched at some point, and generally similar average prices over this tight period.

5.75. We are therefore of the view that Genesis' offers at Huntly 5 were rational given the tight fuel supply and that the high prices were due to market conditions and not an exercise of market power. After the deal with Methanex, Genesis immediately changed the offers at Huntly 5 to reflect the increased supply of fuel.

Rankine offers

5.76. Figure 38 shows the offer tranches for the Rankines. There are three Rankine units that are currently operational, though staffing capacity means that usually only two can be run concurrently. The Rankines can be run on either coal or gas or a combination of both, depending on fuel availability and costs.

Figure 38: Offer tranches at Huntly Rankine units 1, 2 and 4



Source: Electricity Authority

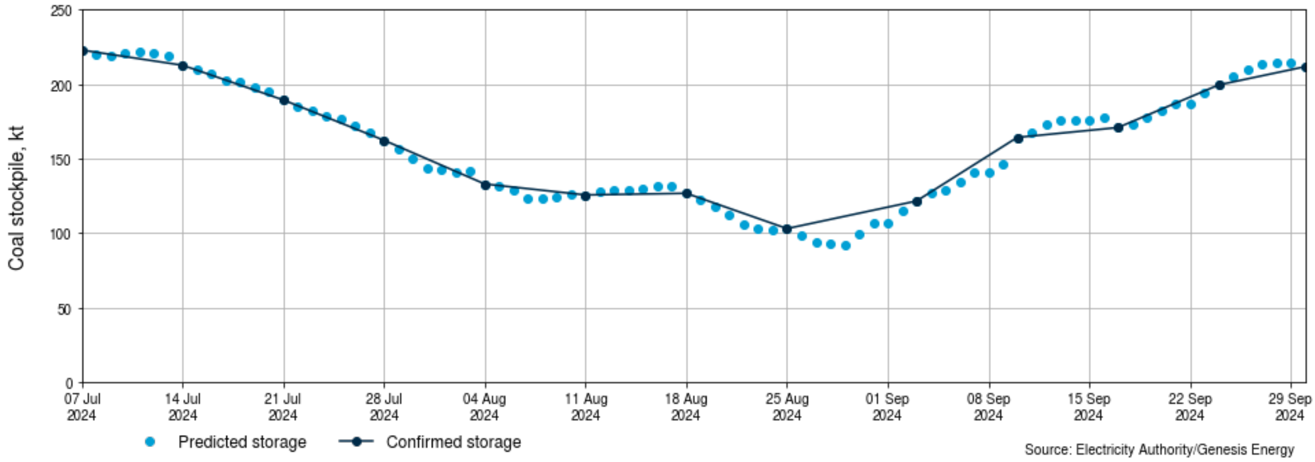
5.77. For most of June, two Rankines were offered into the market, and conditions sometimes reduced this to one Rankine (such as over a windy weekend). However, from mid-July all three Rankines were offered into the market, reducing to two when high wind and/or lower demand reduced supply needed in the market.

5.78. The Rankine generation weighted offers consider all Rankines offered into the market at any given time, and ignores the ones not offered. The weighted offer price was lower in early July when two Rankines were offered into the market. From mid-July this increased to three Rankine units. Most of the Rankine capacity was offered below $200/MWh, however, when all three were offered into the market a higher proportion of the capacity was offered at a price above $500/MWh. As a result, the weighted offer price increased during the period all three Rankine units were running.

5.79. Rankines were predominantly running on coal until early September and then partially fuelled on coal and gas as market conditions fluctuated (Figure 36). When compared to the spot gas price it was cheaper to run the Rankines on coal until early September, after which it appeared to be cheaper to run on gas.

5.80. Figure 39 shows the coal stockpile at Huntly, as reported by Genesis weekly. The light blue markers indicate our predicted coal stockpile between weekly updates from Genesis. This considers coal deliveries received and Rankine generation to predict coal usage. The coal stockpile rapidly declined over July when all three Rankine units were running. The lowest reported weekly value of the coal stockpile was 103kt on 25 August. This is enough coal to run one Rankine at full capacity for a month, or three Rankines at full capacity for around 10 days. Therefore, for prudent management of the coal stockpile, Genesis needed to offer some of the capacity at a price higher than the SRMC of coal, or else risk running out of coal[9].

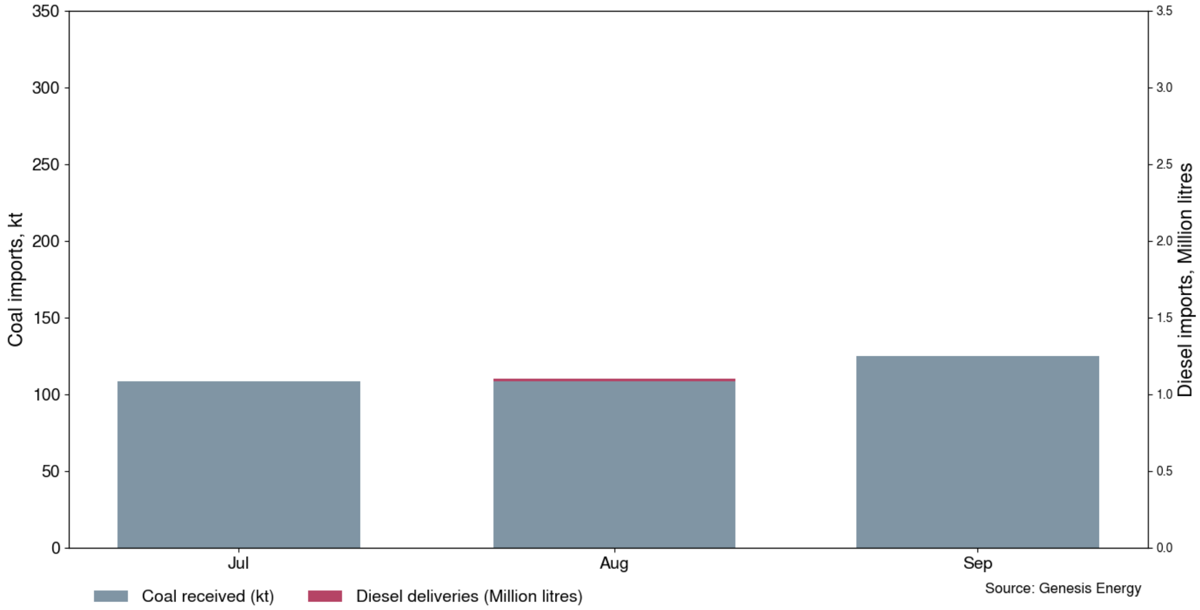
Figure 39: Coal stockpile at Huntly



5.81. Genesis was receiving fuel deliveries during this time, with monthly totals shown in Figure 40. Coal deliveries were around 110kt per month in July and August and increased to 125kt in September. The coal deliveries in July and August were necessary for all three Rankine units to generate concurrently.

5.82. Less Rankine generation, improved gas availability and continued coal deliveries throughout September saw the stockpile increase to ~212kt on 30 September. This is enough coal to run one Rankine at full capacity for at least 50 days. Remaining planned coal deliveries out to 19 December total ~227kt.

Figure 40: Genesis monthly coal and diesel deliveries[10]



[9] The bottom of the coal stockpile is also likely to be lower quality of coal, and therefore less efficient to run, and better to be left as 'pad' coal.

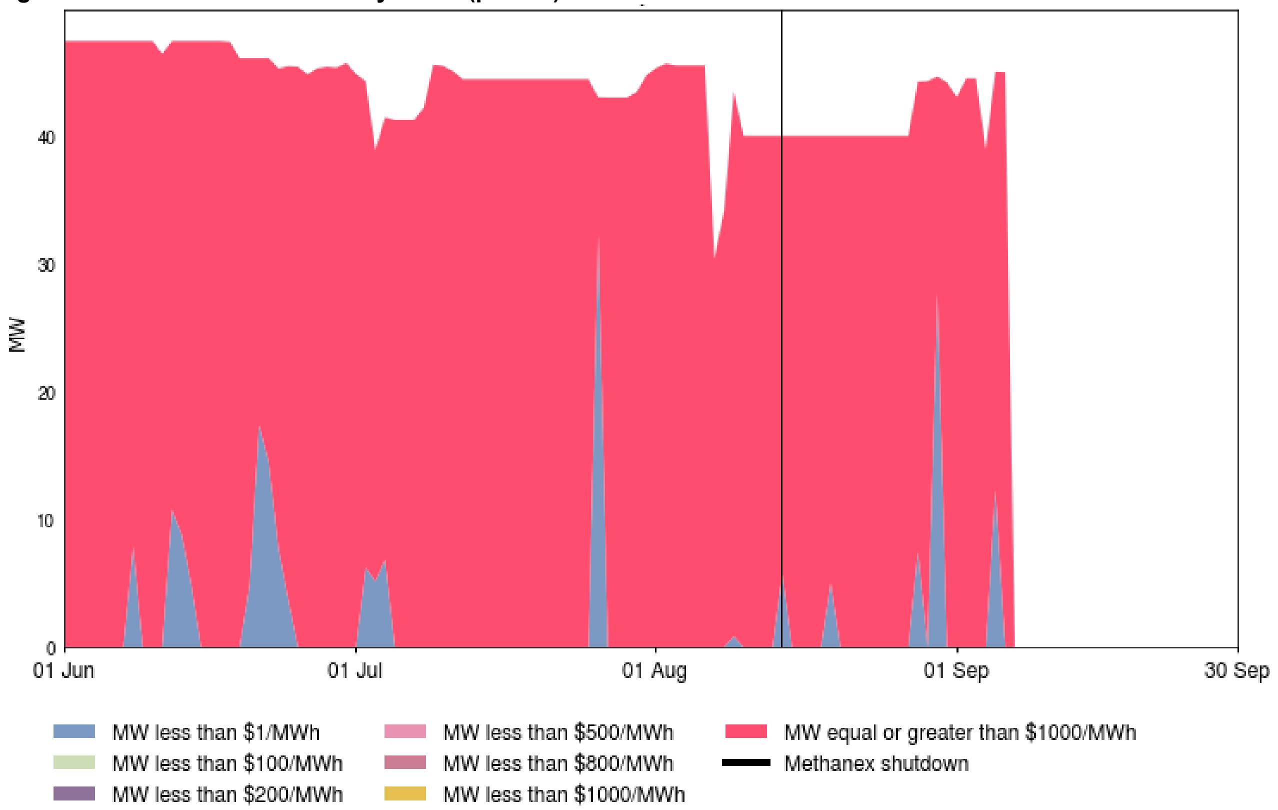
[10] This graph depicts diesel using approximation of 1,000kl to 1,000 tonne to show relative size to coal deliveries. Actual conversion from kl to tonnes is dependent on several factors such as temperature of diesel.

Huntly unit 6

5.83. Huntly unit 6 is a ~50MW peaking unit that can run on gas or diesel. About 12.6 TJ/day would be needed to run Huntly 6 continuously. However, it usually only runs for short periods of time when additional capacity is needed. Huntly 6 was also on outage from 7 September to 3 October.

5.84. Most Huntly 6 offers over this period were above $1,000/MWh, often priced at $5,000/MWh. Given that Genesis had limited gas (and limited diesel storage as discussed further below) and Huntly 6 is less efficient than Huntly 5, it was economically rational to run available gas through Huntly Unit 5 instead of Huntly 6. But Huntly 6 capacity was available if needed for short periods of time.

Figure 41: Offer tranches at Huntly unit 6 (peaker)



Source: Electricity Authority

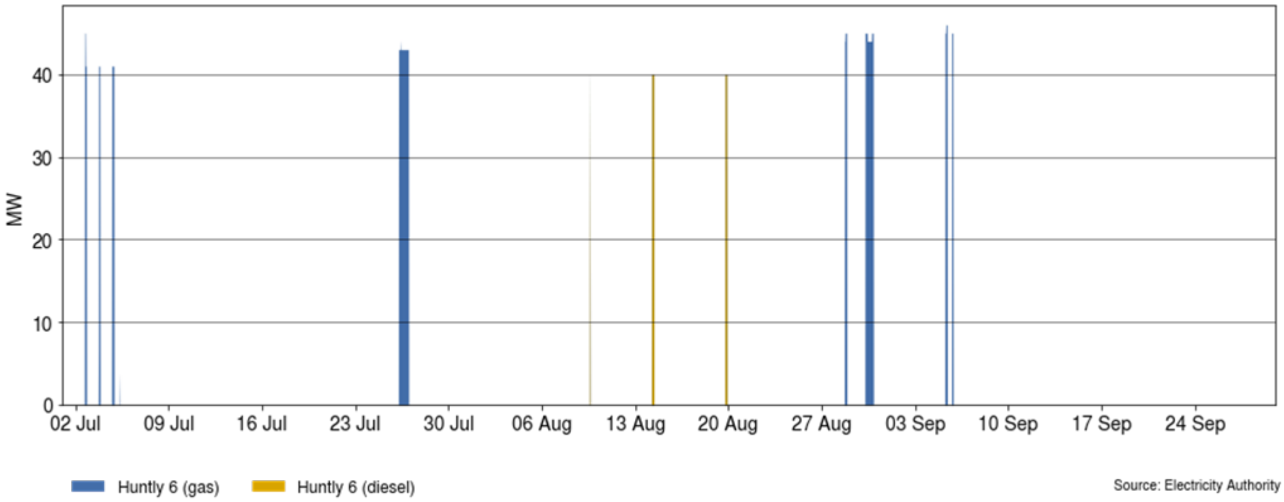
5.85. Figure 42 shows every time Huntly 6 ran from July to September and whether it was fuelled by gas or diesel. It shows that Huntly 6 ran on gas in early July, and then on 26 July, at which time Huntly 5 was on outage. However, during most of August, the few times Huntly 6 was generating it ran on diesel, namely on the 9, 14 and 19 August. During the times Huntly 6 ran on diesel at least 2 Rankines and Huntly 5 were also generating.

5.86. Genesis has only a small amount of diesel kept in storage for generation. At the start of August, they had about 0.31million litres of diesel, which would last less than a day if Huntly

6 generated continuously on diesel. This means that diesel was not a viable alternative to gas for more than short periods of peaking.

5.87. Genesis had a small amount of diesel delivered in late August, which was equivalent to the amount of diesel they used for generation. These deliveries are shown in red in Figure 40.

Figure 42: Huntly 6 generation and fuel type, July to September 2024



Contact

5.88. Contact operates the Taranaki Combined Cycle (TCC) gas turbine (360MW), two open cycle gas turbines (Stratford 1 and 2, 100MW each) and the Whirinaki diesel generator (155MW).

Contact's gas prices and offer prices

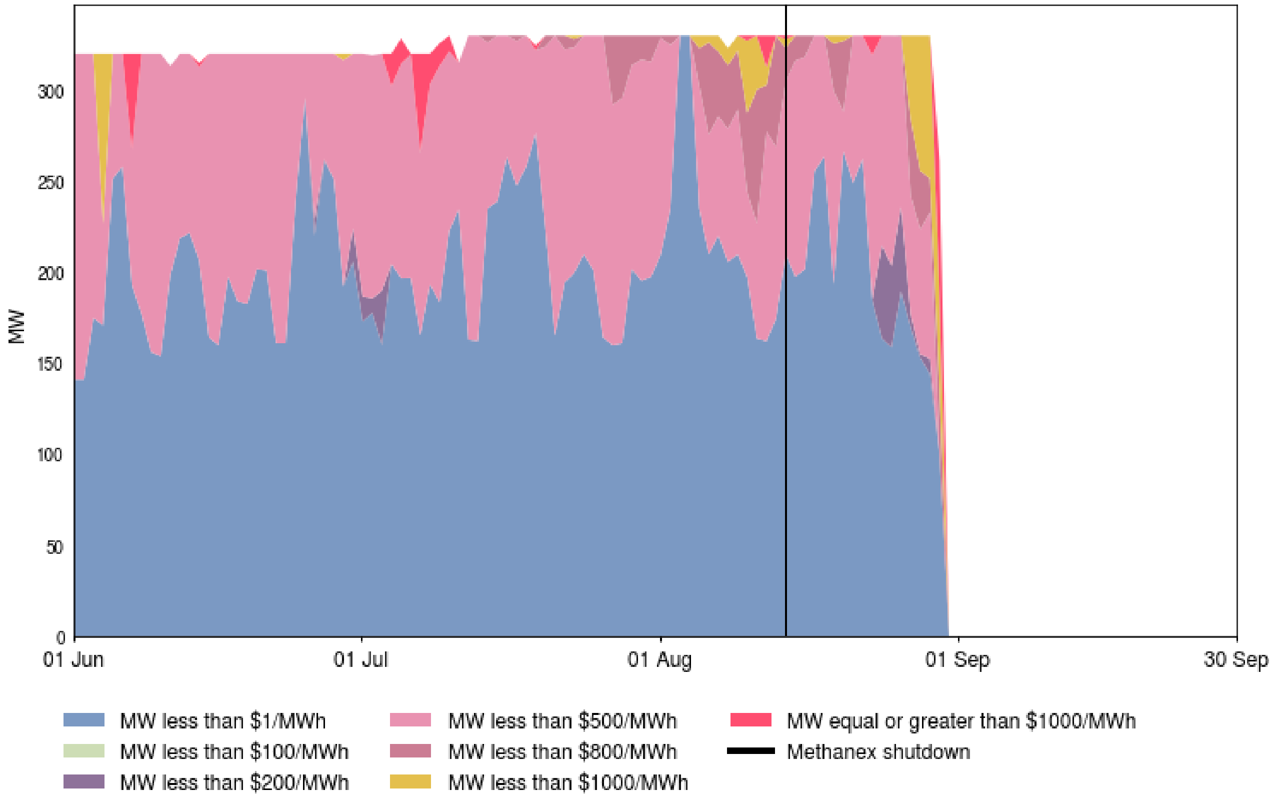
5.89. Stratford peaker 2 has been on long term outage since August 2023, so Stratford offers only represent Stratford 1. These offers are examined below.

5.90. Figure 43 shows the offer tranches at Taranaki combined cycle. During July and August TCC offered more than half its generation at less than $1/MWh, as TCC runs as baseload this would have ensured minimum capacity was dispatched. The majority of the rest of its capacity was offered between $200-$500/MWh. Most of this was offered close to the spot price of gas, at least during the peak periods when TCC's full capacity was needed.

5.91. In early August, more generation was offered at higher prices, particularly overnight and outside peak times. This would ensure there was enough gas to run during the peak periods. However, Contact offered TCC's full capacity at below $1/MWh during periods when generation outages, low wind generation and high demand would have increased its market power, such as on the 3 and 4 August, when one of the Rankines was on outage and prices were reaching over $800/MWh.

5.92. TCC stopped generating at the end of August, by which point high hydro generation and falling demand meant prices had fallen below TCC's SRMC and it was no longer economical to run.

Figure 43: Offer tranches at Stratford's Taranaki combined cycle

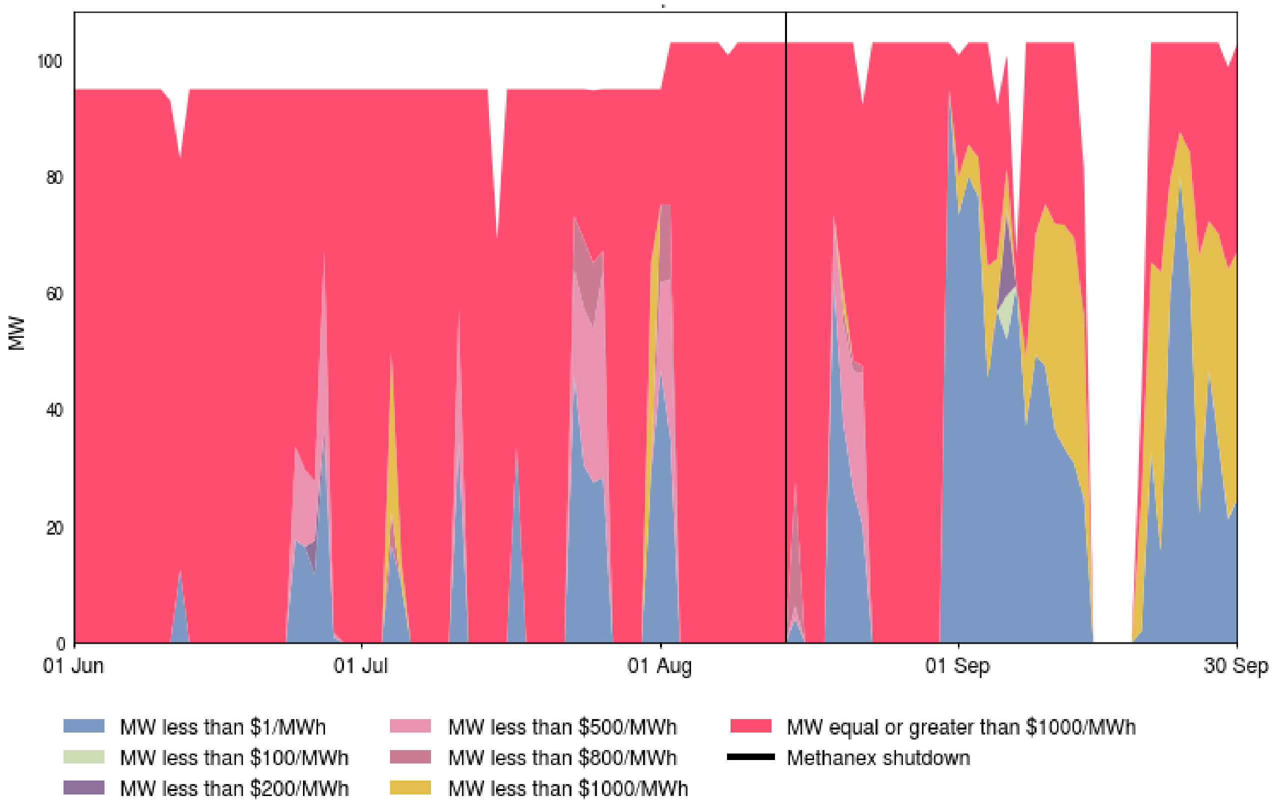


Source: Electricity Authority

5.93. The Stratford peakers would each require about 21.4 TJ/day of gas to run continuously. However, the second of the two peakers (unit 2) was on long term outage this winter.

5.94. Figure 44 shows the offer tranches for Stratford unit 1. Most Stratford unit 1 offers over this period were above $1,000/MWh. However, given that Contact had limited gas, and the peaking unit is less efficient than TCC, it was economically rational for Contact run available gas through TCC instead. But Stratford peaker capacity was available if needed for short periods of time. After TCC shut down on 1 September, Contact offered the Stratford peaker at below $1/MWh for at least part of the day, each day, except when it was on outage from 4-5 September and 14-20 September.

Figure 44: Offer tranches at Stratford's peaker



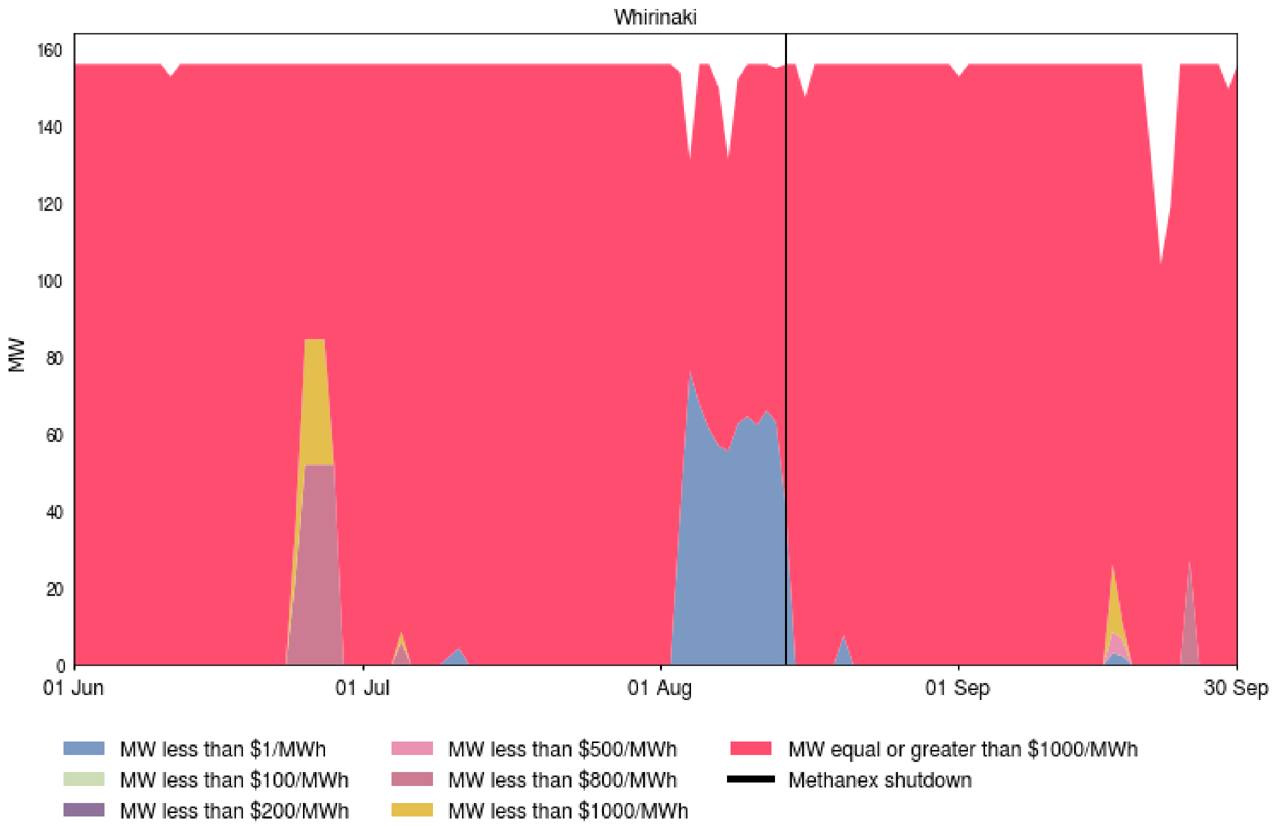
Source: Electricity Authority

5.95. Contact also owns the Whirinaki diesel peaker, however, this unit rarely runs due to the high cost of diesel. The estimated SRMC for Whirinaki was $510-$570/MWh from July to September.

5.96. Most of the time Whirinaki is offered at prices over $1,000/MWh as it is unlikely that prices will be high enough to make it economical to run even if the price reaches Whirinaki's SRMC for a short period. There were times when Contact reduced the offer prices closer to Whirinaki's SRMC.

5.97. Between 3 August and 15 August, Contact offered about half of Whirinaki's capacity at below $1/MWh.

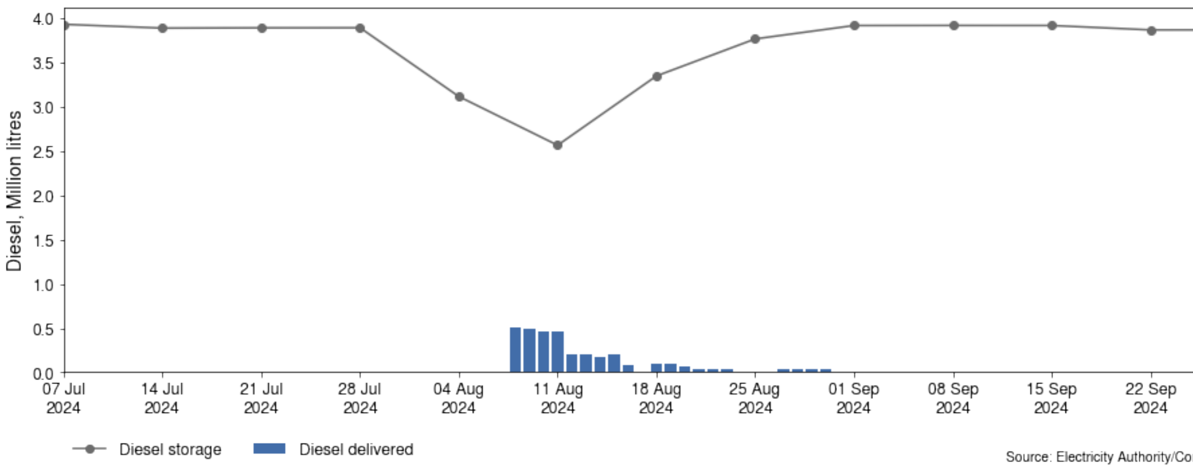
Figure 45: Offer tranches at Whirinaki's diesel peaker



Source: Electricity Authority

5.98. Figure 46 shows Contact's diesel storage and deliveries from July to September. Its diesel storage started July at 3.94 million litres and remained steady until the start of August when Whirinaki capacity was offered at below $1/MWh. Contact then received deliveries of diesel from 8-30 August totalling 3.71 million litres. At the end of September Contact held 3.87 million litres of diesel.

Figure 46: Contact diesel storage and deliveries.



Source: Electricity Authority/Co

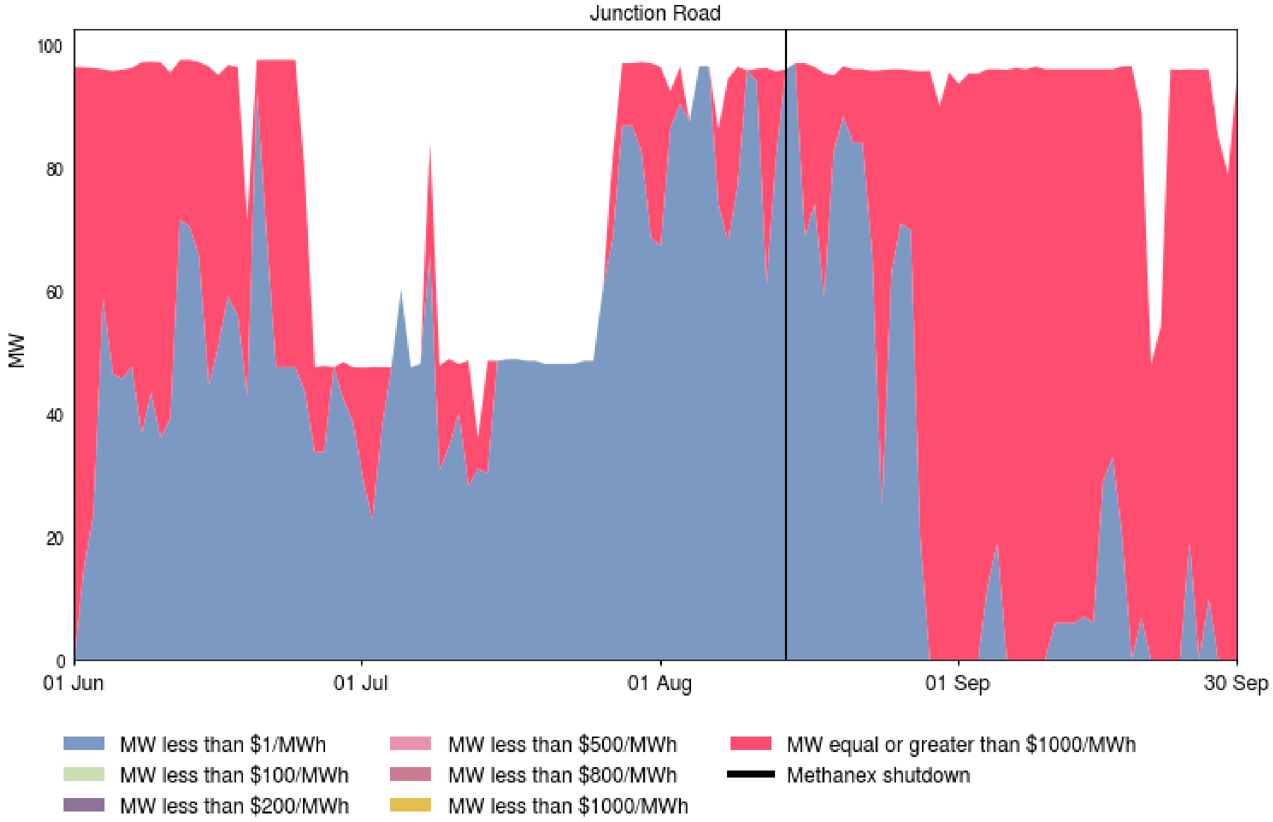
Nova

5.99. Nova Energy Limited (Nova) and Todd Energy (Todd) are both part of Todd Corporation. Nova buys gas from Todd, for its retail customers (including industry and residential customers), for generation and Nova sometimes on-sells gas to other generators. The transfer price that Nova buys gas from Todd is negotiated at around June the previous year. Nova also has a contract with Flexgas to store gas at Ahuroa.

5.100. Nova operates the McKee and Junction Road open cycle gas turbines (100MW each). Both peakers have two units that can generate a maximum of 50MW.

5.101. Figure 47 shows that in June and July Junction Road usually offered one of its two 50MW units into the market during the day, though it often turned off at night. Junction Road's second unit was on outage for most of the period between 25 June and 5 July 2024.

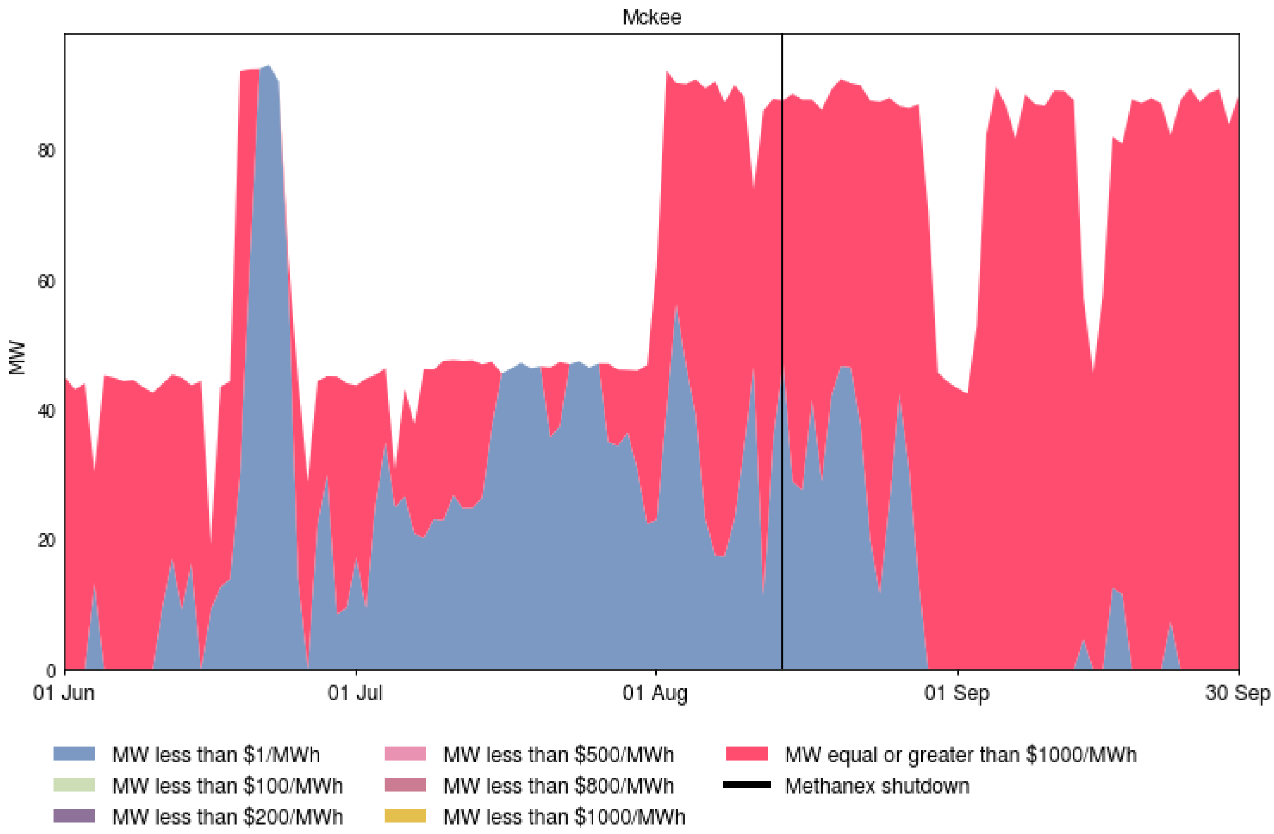
Figure 47: Daily average offer tranches at Junction Road



Source: Electricity Authority

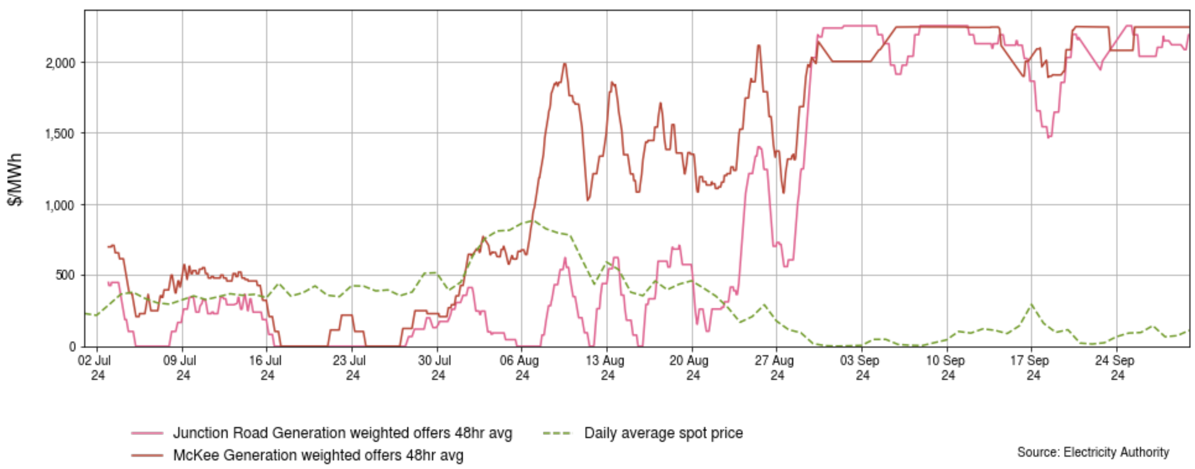
5.102. Similarly, unit 1 at McKee was on outage until 18 June, and unit 2 was on outage from 24 June until 1 August, and between 29 August and 3 September. There were also some other small outages between June and October for all the units. These outages are reflected in total capacity offered, as shown in Figure 48.

Figure 48: Daily average offer tranches at McKee



Source: Electricity Authority

Figure : Junction Road and McKee offers compared to the daily average spot price



Source: Electricity Authority

6. Generators were not making larger margins from higher prices

6.1. On 9 August gentailers were requested to supply energy margin data on a weekly basis, dating back to 1 July 2024. This was in response to reports that gentailers were making 'excessive profits' when spot prices were high. This section presents the findings from this data between 1 July and 29 September 2024.

6.2. The energy margin is the difference between total revenue from generating electricity after total costs from generating electricity. This is not generators' profits as some costs such as staffing and maintenance are not included. However, if energy margins were particularly high for a short period, it could indicate that profits were particularly high at this time.

6.3. To calculate energy margins, we requested several components of revenue and costs. They include:

(a) Generation revenue - this is the revenue that gentailers receive from the wholesale market for generation at the spot price.

(b) Ancillary market revenue refers to revenue from the ancillary market (for providing reserves and other security products) minus any costs paid into the ancillary market (such as paying for reserves when a generation unit is the risk setter)

(c) Other revenue refers to all fixed price electricity contract revenue (energy component only) from physical and financial contracts, inclusive of mass market, commercial, industrial, CfDs, ASX and premiums.

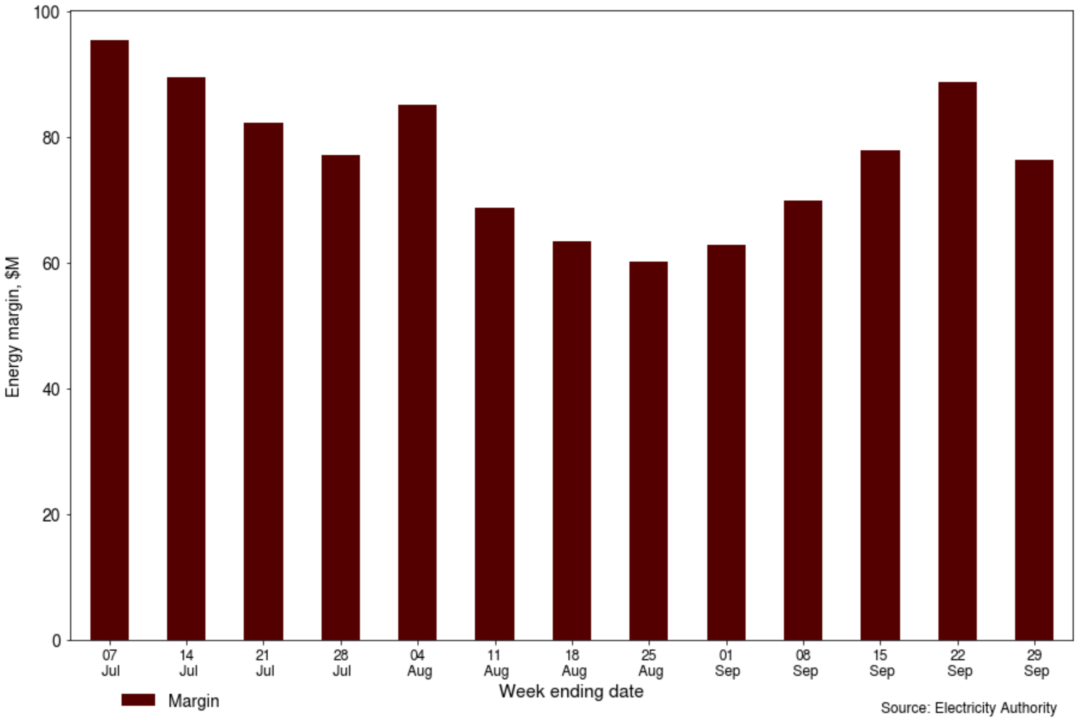
(d) Spot electricity costs refer to floating costs and revenues from physical and financial contracts associated with the wholesale spot price, inclusive of mass market, commercial, industrial, CfDs, and ASX

(e) Direct generation costs are the direct costs for generating, such as fuel and emission costs. The opportunity cost of water is not included. Operating expense (such as staffing costs, maintenance and repair costs) and levies are not included

6.4. Total energy margin across all gentailers (Figure 49) has varied from $60 million to $90 million per week, with an average energy margin of $77 million. Overall margins decreased between the week ending 7 July and 18 August then rose again until the week ending 22 September. The exception to this was 4 August when margins were higher than the surrounding weeks, and 29 September when margins fell. The higher energy margin on the week 4 August appears to be due to revenue from fixed price contracts, which was $107 million, compared to the average of $98 million. This is most likely due to high demand during this week, which increased revenue from retail customers. High energy margins in early July were also likely related to high demand.

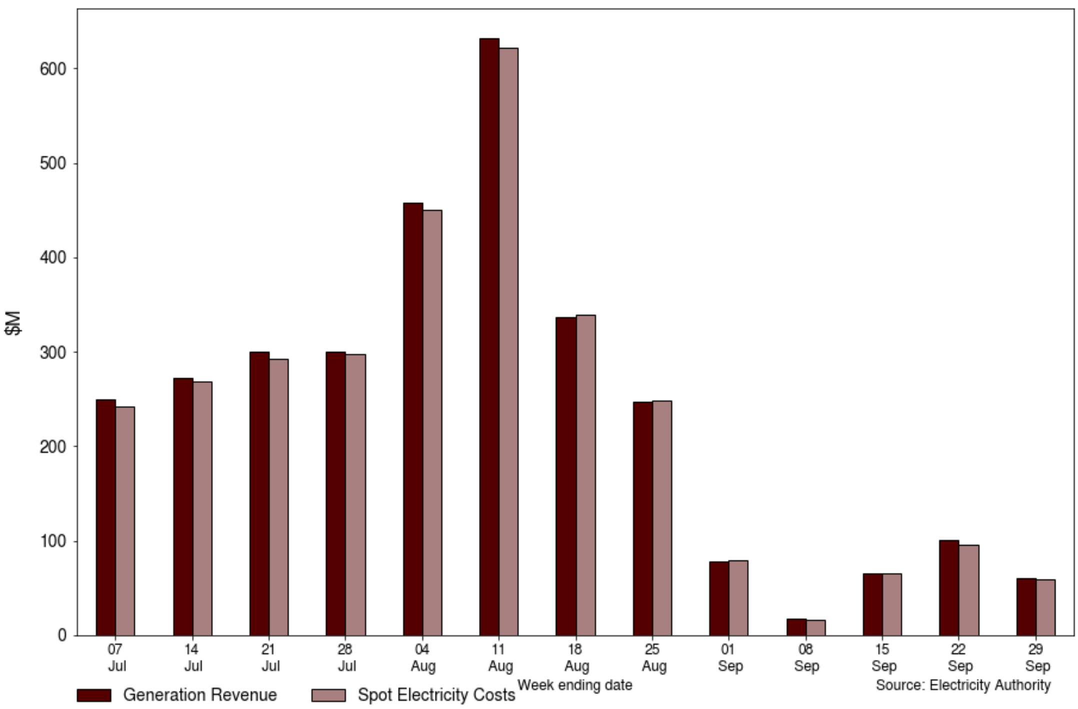
6.5. The weeks where the total energy margin was the lowest were also the weeks when direct generation costs (fuel) was the highest. In early August high gas prices of thermal generation results in direct generation costs between $36-$39 million per week. In contrast, in September when there was a higher amount of renewable generation, direct generation costs were around $13 million per week.

Figure 49: Total energy margin across all gentailers



6.6. Both generation revenue and spot electricity costs are directly related to the wholesale electricity spot prices. Both were highest in the week ending 11 August, which was the week with the highest spot prices, with generation revenue at $632 million and spot electricity costs at $622 million. Both dropped much lower in September as prices dropped.

Figure 50: Total generation revenue and spot electricity costs across all gentailers

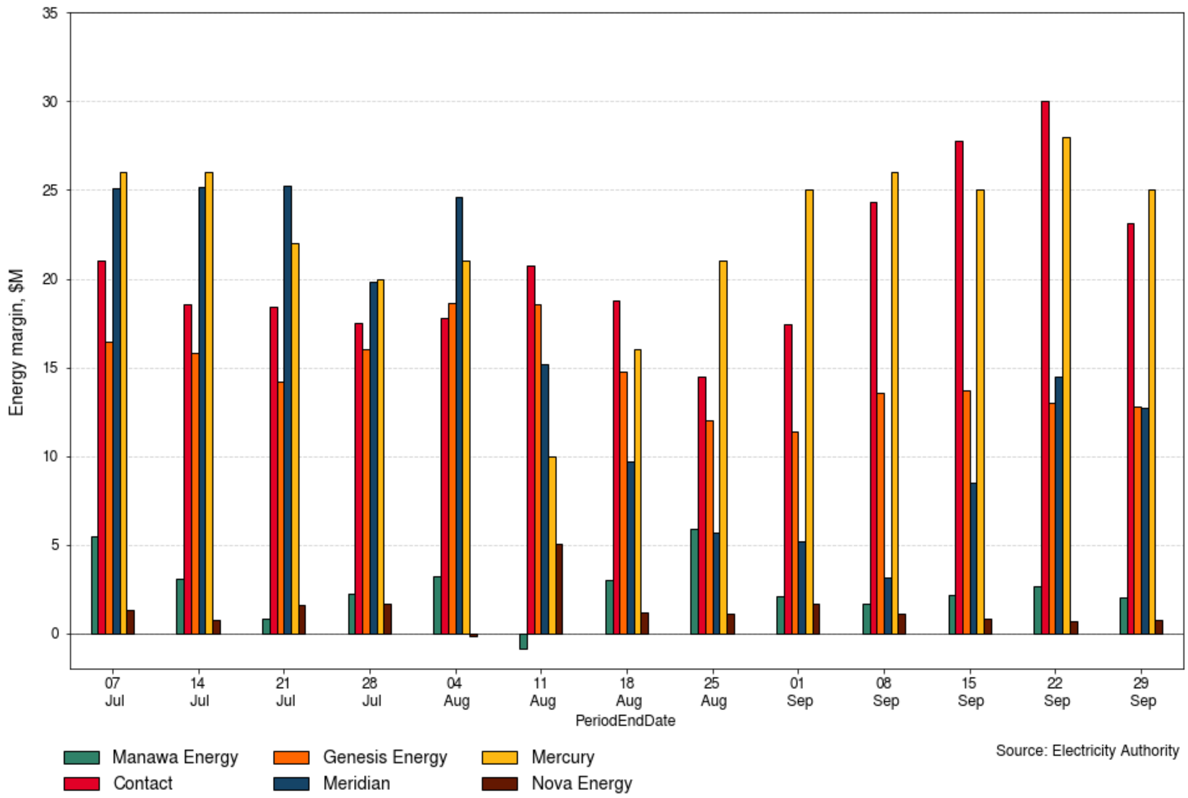


6.7. While high prices did greatly increase generation revenue, this did not translate through to higher energy margins. In Figure 50we see that in the week ending 11 August and the week ending 9 September the energy margin was similar, but generation revenue was vastly different between the two weeks, due to very different conditions in the market. However, as gentailers were also the main buyers at these high prices, the net impact of high prices was small. However, this does not mean that individual generators did not benefit from high prices in the market.

6.8. Each gentailer's energy margin tended to be higher in the weeks in which that generator's output was highest. For example, Genesis' revenue was highest in the weeks it had all three Rankines and Huntly 5 generating, while Contact and Mercury benefited from high inflows in September.

6.9. Nova, having the smallest generation capacity, has the lowest margins most weeks. Nova's energy margin was highest at $5 million in the week ending August 11, due to the high dispatch of the available peaker units. Nova has stated that its energy margins overstate the profitability of its business as they buy gas at a transfer price from Todd, but that Todd has taken a hit in profitability because of lower gas volumes and relatively fixed production costs.

Figure 51: Energy margin by week for all gentailers



6.10. However, there were other factors that may have influenced the energy margins. Meridian's energy margin was highest in July and lowest early September, despite increased generation. This was due to Meridian's direct and indirect funding of demand response arrangements.

7. Competition in the retail market temporarily declined

7.1. Overall, the high prices in the wholesale market only directly impacted retailers and industrial customers who bought load directly from the wholesale market. While prices did not flow through to the retail customers, some retailers either stopped promoting retail offerings to attract new customers or increased the price for new customers, in order to minimise their exposure to the high wholesale prices.

Figure 52: Domestic electricity prices by component not adjusted for inflation (base Q3 2024 CPI)

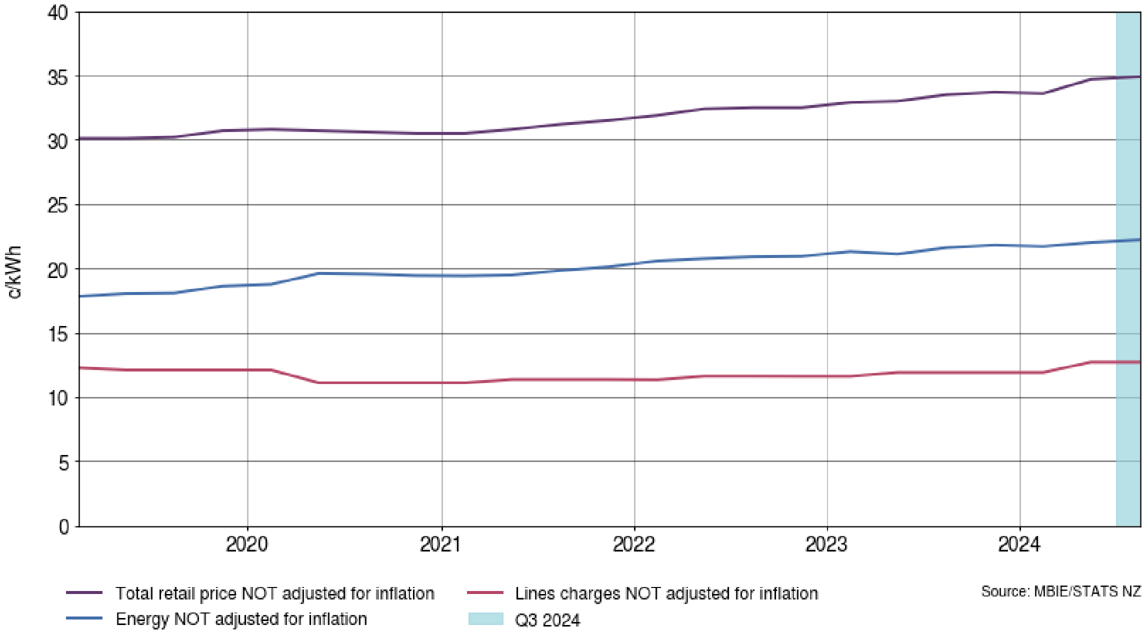
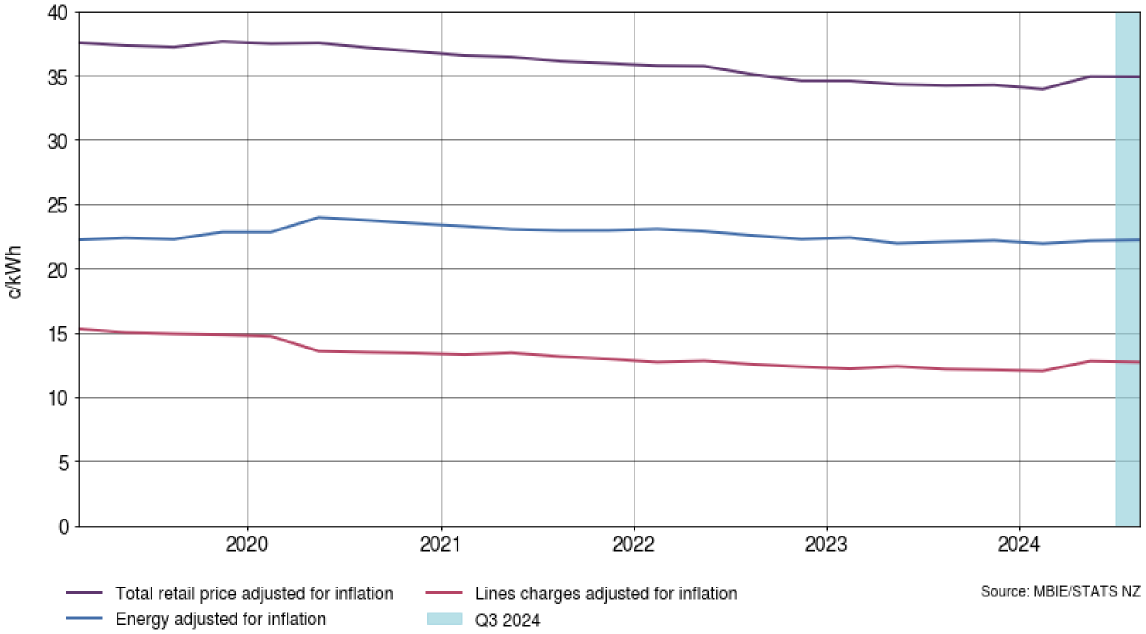


Figure 53: Domestic electricity prices by component adjusted for inflation (base Q3 2024 CPI)



7.2. Figure 52 shows domestic electricity prices (QSDEP) since 2019, the top chart being the nominal price and the bottom chart showing the real price. There was a small increase in the nominal price during Q3 2024, but this was less than the increase in Q2 2024 (which was driven by increased line charges). This increase in Q3 was in line with the CPI, so in real terms there was no change in prices.

7.3. In response to the high wholesale and gas prices seen over winter, many retailers appear to have attempted to limit the number of new customers signing up to their services in July and August:

(i) Megatel (Nova subsidiary) stopped listing its services on Powerswitch but were still accepting new customers (apart from high usage businesses).

(ii) Contact Energy adjusted its gas pricing.

(iii) On the 18 July Electric Kiwi announced it had stopped accepting new customers, citing elevated wholesale prices as the reason[11]. Electric Kiwi also ended its PowerShifter and Prepay 300 plans on August 29, with customers on these plans transferred to their Move Master plan.

(iv) Electric Kiwi and Flick Electric requested to have their plans temporarily removed from Powerswitch search results, though we understand that Flick Electric were still taking on customers who approached them directly.

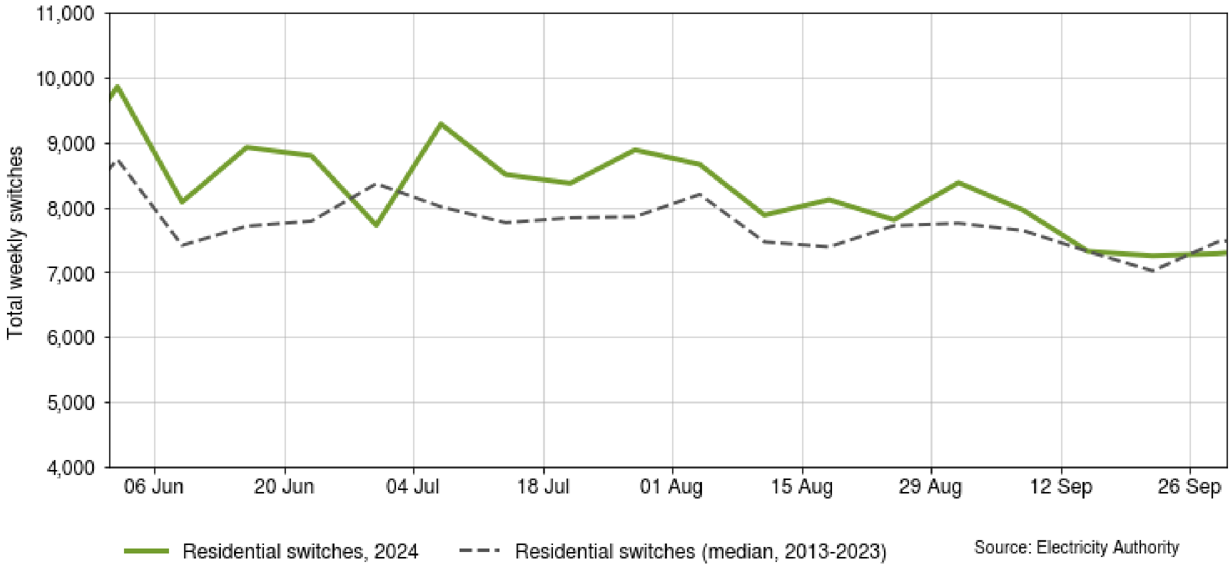
(v) Additionally, two retailers (Comtricity and Raw Energy) closed permanently.

7.4. Retailers without generation usually buy hedges either over the ASX or OTC to reduce their exposure to high retail prices. Retailers will estimate the amount of hedge cover needed based on their current customer base and expected growth.

7.5. Figure 54 shows the number of residential retailer switches each week from 1 June to 30 September 2024, compared to the median of the last 10 years. The weekly number of switches in 2024 was generally close to or higher than the median. This is consistent with the trend of retail switching increasing over time; from 2013 to 2023 the number of residential switches during winter (June to August) increased by an average of 992 each year. The number of switches this winter increased by 3,679 compared to the previous winter.

[11] https://blog.electrickiwi.co.nz/why-is-electric-kiwi-not-taking-new-customers.

Figure 54: Residential switches (excluding half-hourly) from June to September 2024

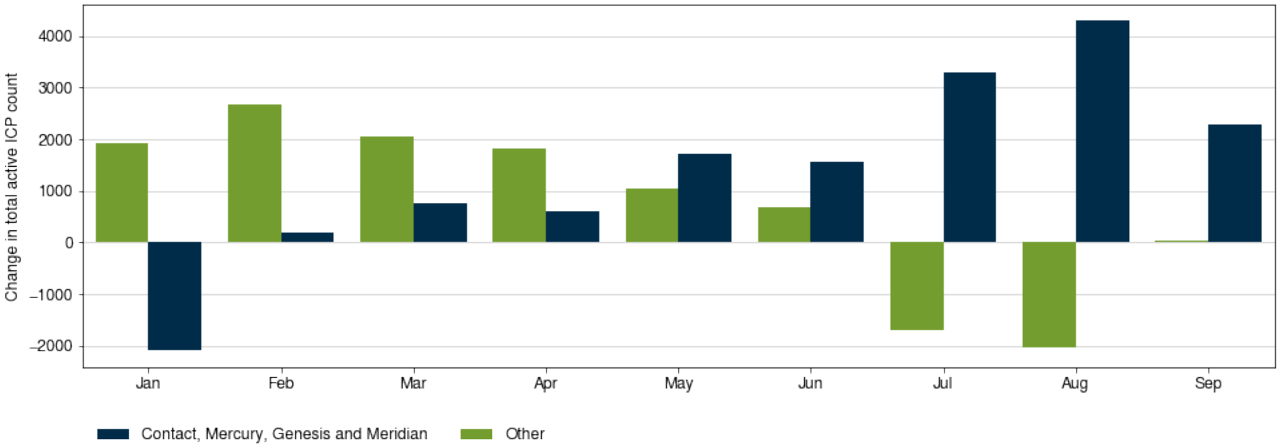


7.6. The overall market share of small and medium-sized retailers does not appear to have been significantly impacted by high wholesale prices. Each month in 2024, ~72% of all active ICPs were customers of the four largest retailers (Genesis, Meridian, Mercury and Contact) with the remaining ~28% being customers of other, smaller, retailers.

7.7. Figure 55shows the monthly change in total active ICPs by type of retailer from January to September 2024. Although overall market share was not significantly impacted, large retailers experienced their highest net gains of the year between July and September 2024. Small and medium sized retailers experienced net losses during July and August, with a net gain of only 47 ICPs in September.

7.8. Overall, this indicates that the actions taken by small retailers to not be listed on switching websites, such as Powerswitch, likely decreased consumer choice this winter, leading to more consumers switching to the larger retailers.

Figure 55: Change in total active ICPs by retailer and month from January to September 2024



8. Future prices reacted to changing supply conditions

8.1. The forward price market saw a lot of fluctuations to near term prices across winter. Figure 56 and Figure 57 show the quarterly forward prices at the start of July, August and September, at both Ōtāhuhu and Benmore respectively.

8.2. At the start of July, the September prices were reasonably high and close to $250/MWh at both Ōtāhuhu and Benmore. There was a small increase in hydro storage at the end of June, however this price was reflective of the overall consistent decrease and lack of inflows affecting the major hydro storage lakes.

8.3. By the beginning of August hydro storage was nearing record lows. This combined with gas availability concerns saw September forward prices reach ~$500/MWh. The knock-on effect of this into the following quarters was also evident with prices up to September 2025 sitting close to or above $300/MWh.

8.4. The Methanex gas deal led to some relief in mid-August, then soon after several fronts passing over the South Island hydro catchments saw the steep increase to hydro storage. The forward market reaction for near term contracts was price drops of around $180/MWh.

8.5. Longer term futures have remained relatively steady with less extreme fluctuations and generally a downward trend. This is likely due to expectations around increased future capacity with the generation investment pipeline.

Figure 56: Quarterly forward prices at Ōtāhuhu

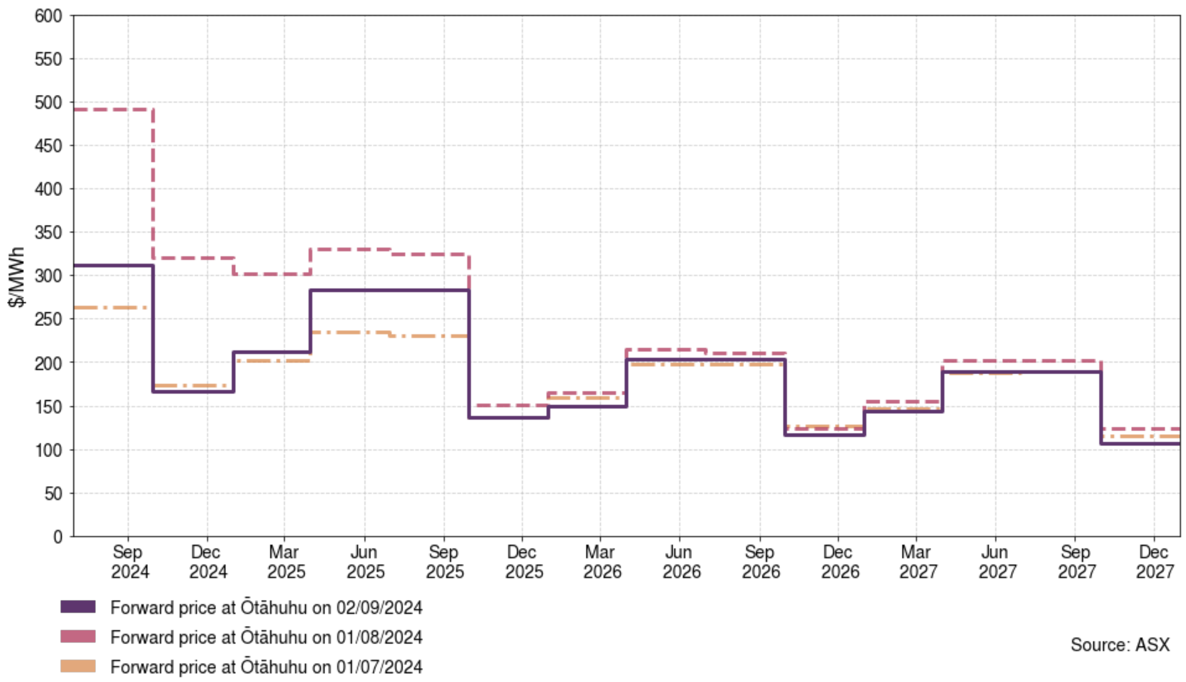
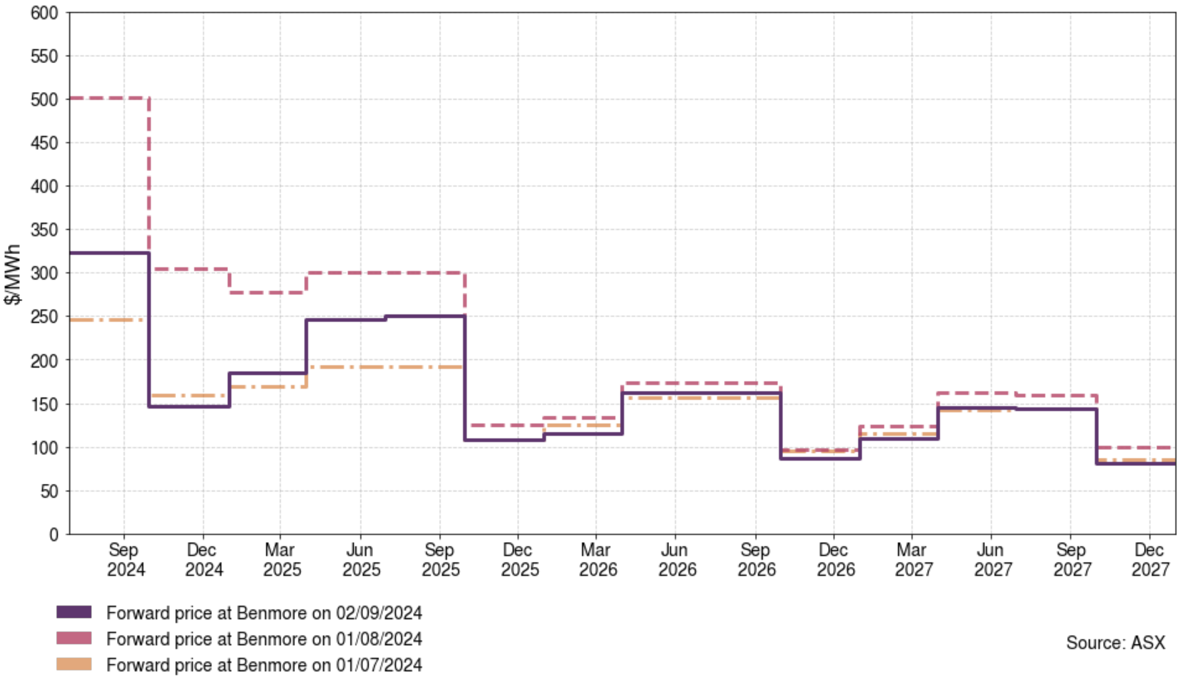


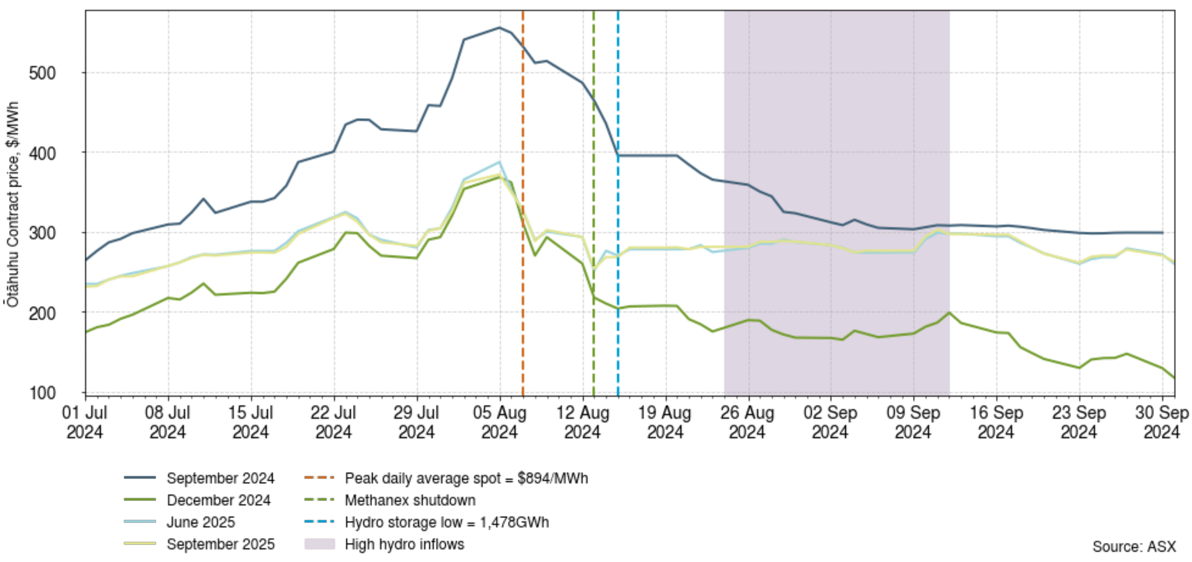
Figure 57: Quarterly forward prices at Benmore



8.6. Figure 58 illustrates the daily settlement figures over time, focussing on September and December 2024 futures and June and September 2025 next year. Key dates have also been highlighted including the Methanex shutdown and significant hydro storage changes.

8.7. There was a gradual increase as we progressed through July, before a steep increase the last week of July into the first week of August. Following the shutdown of Methanex on 13 August there was a notable decrease in the September 2024 and December 2024 prices.

Figure 58: Forward prices over time with key events highlighted



9. There were several impacts on industrial electricity users over winter

9.1. High gas and electricity prices have resulted in reduced output by several large industrial who are large energy users (either gas or electricity). This section describes these impacts including those at Methanex, Tiwai and across the paper and pulp sector.

Industrial and commercial retailer switching was similar to last winter

9.2. Figure 59Figure 60respectively show the number of industrial and commercial retailer switches each week from 1 June-30 September 2024, compared to the median of the last 10 years. Switching rates for both market segments were similar to the historic median. The number of industrial and commercial switches decreased this winter compared to the previous winter, but to a lesser extent than between winter 2022 and 2023.

Figure 59: Industrial switches (excluding half-hourly) from June to September 2024

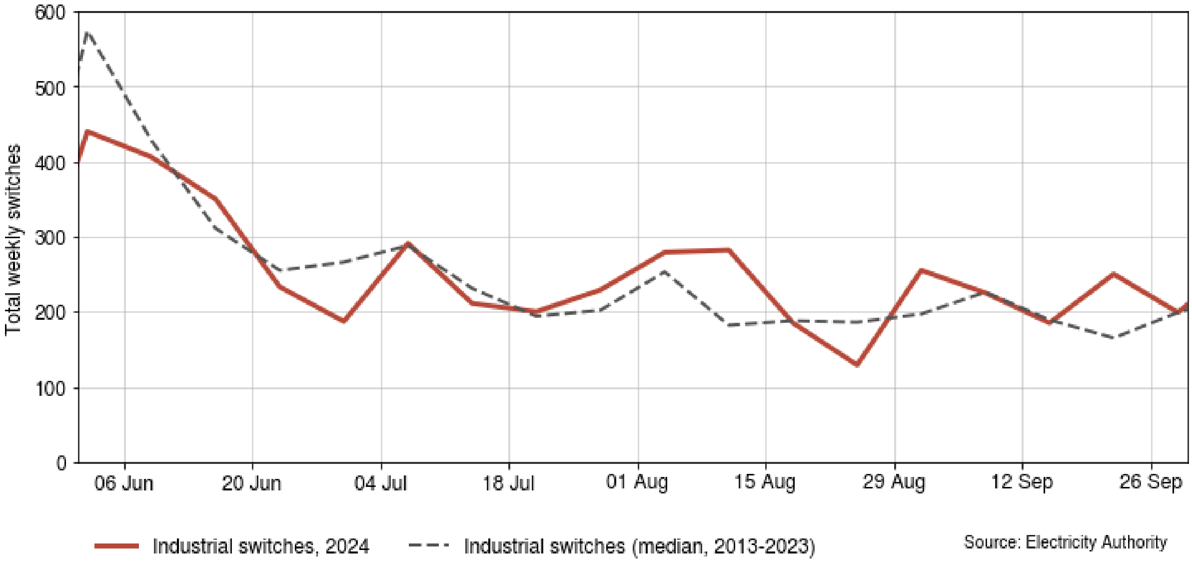
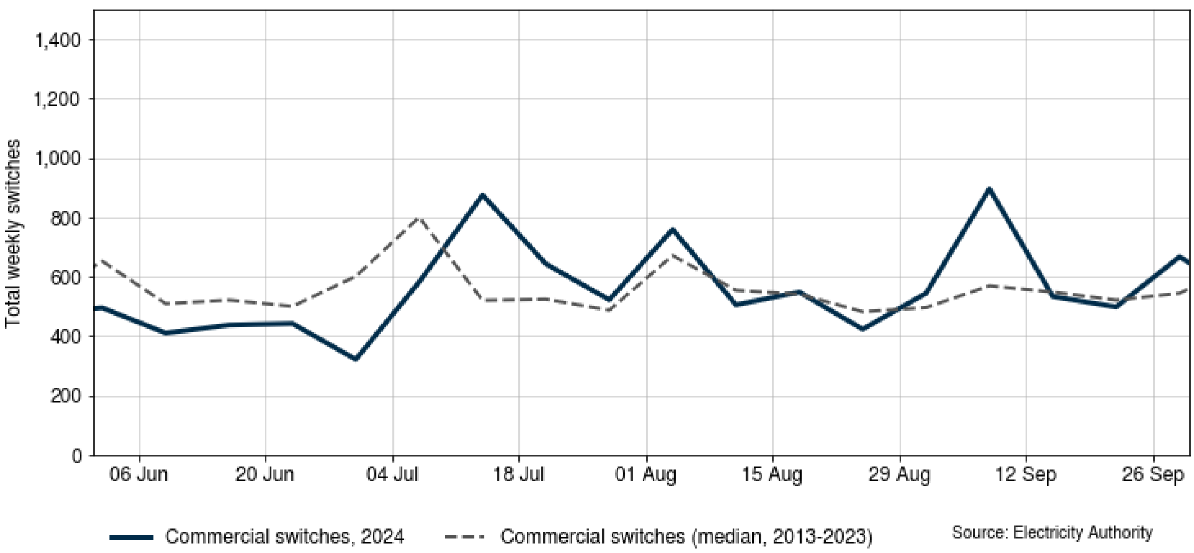


Figure 60: Commercial switches (excluding half-hourly) from June to September 2024



Tiwai aluminium smelter reduced its consumption after Meridian called on its demand response deal

9.3. New Zealand’s largest electricity user, the Tiwai aluminium smelter, also began turning down its electricity demand in June. The Tiwai smelter accounts for more than 10% of New Zealand’s electricity consumption.

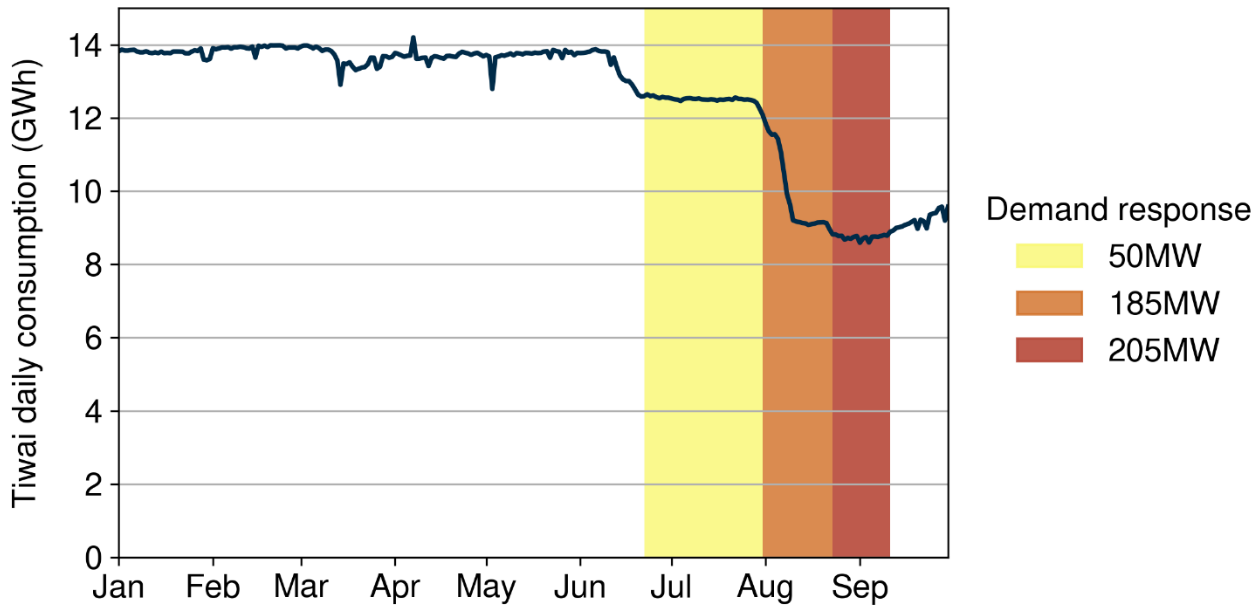
9.4. Tiwai has contracts with three of New Zealand’s largest electricity generators (Meridian, Contact and Mercury). The contracts with Contact and Meridian have a demand response agreement, where Tiwai can be paid to reduce their electricity usage. This enables the smelter to remain economically viable while it has turned down production, and for Contact and Meridian to conserve water in their hydro storage schemes.

9.5. A 50MW demand response call was made by Meridian in June 2024 and, following a ramp-down period, was in full effect from 22 June. In July 2024, a further 185 MW demand response notice was issued by Meridian and, following a further ramp-down period, was in full effect from 19 August. Figure 61 shows the electricity usage at Tiwai point in 2024 with each of their demand response increases.

9.6. From 10 June to 30 September 2024, the Tiwai point demand response saved ~330GWh of electricity, which is equivalent to 7% of New Zealand’s total hydro storage capacity.

9.7. During winter 2025, the 100MW and 185MW demand response options will not be available due to the stand-down periods in the contract. Only the 25MW and 50MW options will be available from 1 July, unless Tiwai voluntarily agrees to provide additional demand response.

Figure 61: Consumption at Tiwai aluminium smelter from January to September 2024



Source: Electricity Authority

Methanex had low production which further reduced after deal with Genesis and Contact

9.8. Methanex has two production lines at Motunui, but production was heavily curtailed over winter 2024 due to an overall tight gas market.

9.9. Methanex agreed to sell its remaining gas supply to Contact and Genesis from 13 August, which saw it mothball its plant until the end of October. Methanex stated they would use the period when the plant was idle to complete maintenance[12].

10. Outlook for winter 2025

10.1. Further information regarding the outlook for winter 2025 can be found on the Authority's insights page and on the system operator's security of supply webpage.

[12] https://www.nzherald.co.nz/business/companies/energy/methanex-sells-contracted-natural-gas-for-more-than-it-can-earn-making-methanol/