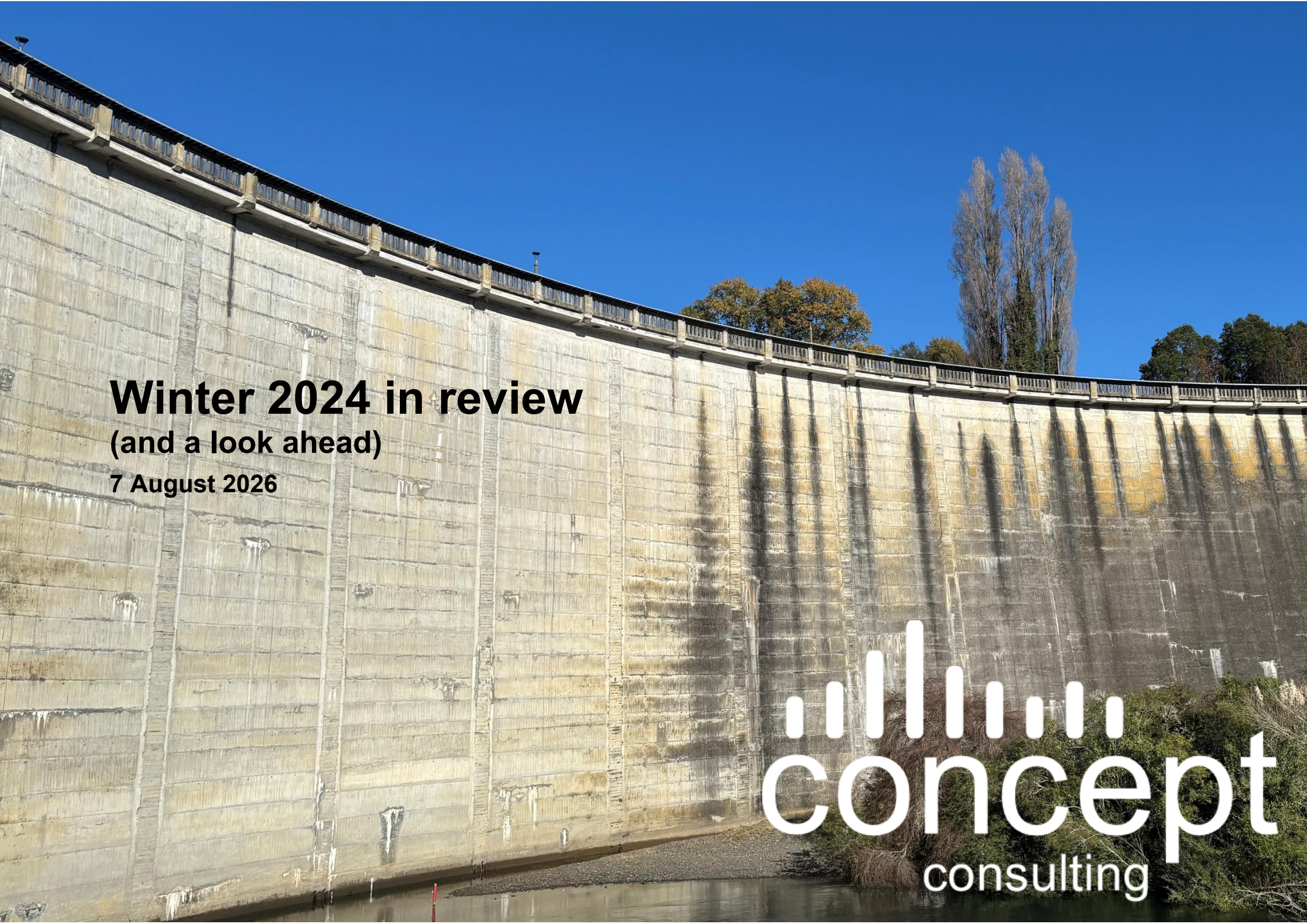

Winter 2024 in review

(and a look ahead)

7 August 2026

concept consulting

About Concept Consulting Group

We have been providing useful, high-quality advice and analysis for 25 years. Our roots are in the electricity sector and our practice has grown from there. We have developed deep expertise across the wider energy sector, and in environmental and resource economics. We have also translated our skills to assignments in telecommunications and water infrastructure.

Our directors have held senior executive roles in the energy sector, and our team has a breadth of policy, regulatory, economic analysis, strategy, modelling, forecasting and reporting expertise. Our clients include large users, suppliers, regulators and governments. Our practical experience and range of skills mean we can tackle difficult problems and provide advice you can use.

Since September 2024, we have offered off-the-shelf electricity price forecasts that build on our deep knowledge of the New Zealand energy sector, and the modelling tools and datasets we have developed through our extensive consulting work for government, regulators, investors and market participants.

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Contributors

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1 Winter 2024 in review

Purpose of this report

We are publishing this report to stimulate discussion and to demonstrate and verify the capabilities of our modelling toolset. Any feedback on either topic is welcomed.

This report produces some preliminary findings, but is not an exhaustive investigation. We raise some potential areas for additional analysis, and are open to working with interested parties further.

This report makes up part of our Q2 2026 quarterly price forecast report. For any questions on Concept's modelling capabilities, contact David Weaver or Simon Coates.

What happened in 2024?

Winter 2024 saw weekly electricity spot prices peak at ~800 $/MWh.[1] It contributed to sustained high hedge prices, which put pressure on some electricity consumers, and led to increased political scrutiny for the sector.

On the other hand, New Zealand is currently in a generation build boom, and the high prices from 2024 will have contributed to this.

The reasons for the high prices are complex, and many commentators have attempted to oversimplify the situation to support their favourite argument. Some contributing factors include:

- Low gas supply for power generation
- Lower *than expected* gas supply (which isn't the same as the above)
- Demand uncertainty about New Zealand's Aluminium Smelter (NZAS) at Tiwai Point leading to underinvestment in renewables by existing parties
- Low inflows into hydro generation catchments
- Low start-of-year storage in hydro generation catchments
- Low coal stockpile at the Huntly power station

The Electricity Authority (EA) released a review of winter 2024,[2] which covered some of the bullet points above, and also looked closely at hydro operator behaviour. To summarise a 50+ page paper in a couple of sentences, it found that most of the issues above contributed and that generator offer behaviour during the crunch period was largely consistent with underlying market fundamentals.

Two notable points from the list above that weren't covered in the EA review are the "underinvestment" hypothesis and distinguishing between "low gas supply" and "lower than expected gas supply". This is because the review was more operationally focussed – it was very much about what happened in the "heat of the moment", and longer-term investment appeared to be outside its focus.

Some ongoing calls for market reform are undoubtedly amplified by memories of 2024, and indeed, many of the proposed initiatives would have helped in 2024. Such initiatives include:

- Allowing easier access to contingent storage at Lake Pukaki in the South Island for hydropower generation
- An LNG (Liquefied Natural Gas) import terminal
- Increased underground gas storage
- Increased diesel storage and generation capability at Marsden Point, or conversion of existing gas peakers to dual fuel
- Improved trading of Methanex (New Zealand's largest gas user and producer of methanol) gas entitlements to higher-value electricity generation during dry periods
- Investment in an increased coal stockpile at Huntly power station and re-furbishing the Rankine generating units at Huntly

What does this report do?

This report begins by diagnosing what happened in 2024. We use our model to recreate system conditions at the start of the year and see how the model predicts the year would play out. Any differences highlight areas to investigate more closely. This part of the report is similar to the EA's review. When compared to their analysis, one difference is that we look at

[1] Unless otherwise stated, we use North Island prices in this report.

[2] https://www.ea.govt.nz/documents/7159/Review_of_winter_2024_jnOSQfc.pdf

operator behaviour across the whole year, rather than just the few months of winter. Therefore, we come up with slightly different conclusions.

Our next step is to consider how different market initiatives might have made 2024 play out differently. We implement some possible initiatives in our model and see what effect that would have had on prices.

However, this is of limited use, since the world of the future is very different from the world of the past. To this end, we also test how some of the initiatives might affect things in 2028. We are not entirely forthcoming in this section (we don't show modelled 2028 prices), since providing forecasts is a key part of our business. However, we show price *changes* and changes to thermal utilisation, and these are illustrative of how 2028 is very different from 2024.

The Appendix shows the model verification process where we compare our modelled 2024 results to actual 2024 results.

What does this report conclude?

Firstly, our **review of the model** concludes that it predicts historical outcomes well. This is a key building block to undertaking this analysis and drawing conclusions from our counterfactual modelling.

Our key findings for **what happened in 2024** are:

1. 2024 was not a particularly "dry year" for hydro power generation. Worse inflow sequences would have driven even worse outcomes.
2. We could have gone into winter with storage lakes slightly higher, and this would likely have led to less extreme market outcomes in August. Note that:
    a. We're well aware that making this statement with the benefit of hindsight is easy – and this isn't a critique of operator behaviour at the time.
    b. Inaccurate market expectations for thermal fuel supply (coal and gas) likely contributed to this.

Our review of how different **changes to the market** would have affected outcomes can be summarised in these two charts.

Figure 1 - Modelled price changes for 2024[3]

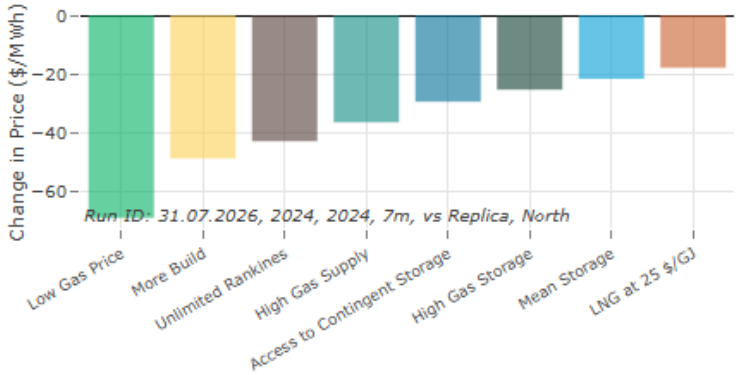
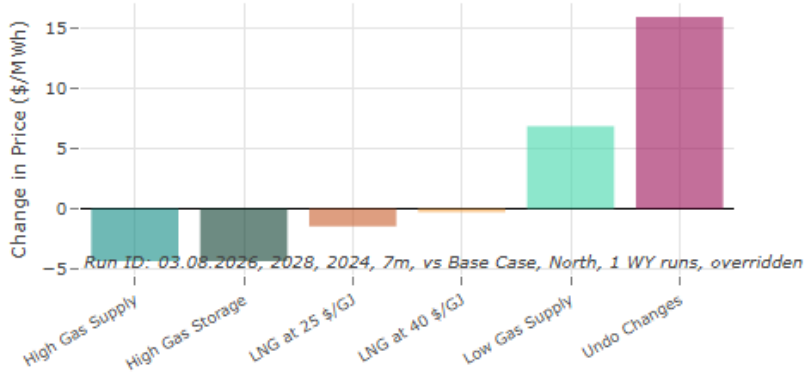


Figure 2 - Modelled price changes for 2028[4]



[3] Results are shown for the first ~7 months of 2024, with actual 2024 weather, up to the period when sustained prices exceeded 800 $/MWh (and the subsequent collapse). Details of each scenario are provided in the body of the report.

[4] Comparable period and weather shown for 2028 as for the preceding 2024 chart.

These two charts show price impacts of various changes to the market, both looking backwards and looking forwards, and they are clearly showing two different worlds.

In 2024 the system was short of energy, so any of the modelled initiatives would have helped, most notably more gas supply, more renewable generation and/or more availability from Rankine units.

In 2028, any initiative's effect on the market is much lower. While we do not show our forecast prices (as this is part of our forecasting service), our modelled prices are broadly consistent with the current Otahuhu forward electricity price of 120-130 $/MWh. Prices at this level reflect a system roughly in balance – unlike 2024.

Indeed, three of the "initiatives" from 2024 will have been put into practice by 2028 and are included in our 2028 base case modelling:

- 2024's "contingent storage" scenario (lower minimum lake levels on the Waitaki) has been put into practice with recent changes to the allowed operation of the Waitaki scheme.
- 2024's "unlimited Rankines" scenario (additional availability of Huntly Rankine unit) has been put into practice with Genesis's renewed commitment to three Rankine units as a result of a successful HFO procurement process.[5]
- Net commissioned and committed build between 2024 and 2028 has exceeded the build in the "more generation" scenario.

With that context, it is unsurprising that the three remaining initiatives considered (changes to gas supply, changes to gas storage and LNG import), will have much less impact in 2028 than they would have in 2024.

DOA spiral?

We modelled LNG price as 25 $/GJ. This is consistent both with other modelling on the issue and also the international price of LNG plus a small margin. However, this price may underestimate the price that would correctly account for the cost of LNG infrastructure.

It is potentially the case that not *all* of the cost of an LNG import terminal should be recovered from LNG sales, particularly if it is providing a security of supply service for the market.

However, it would also not be correct to not recover *some* of the costs of the terminal through LNG sales, and to this end, we also looked at a scenario with LNG priced at 40 $/GJ. This scenario has both much lower impact on prices as well as much lower LNG use.

Additionally, with a lower volume of LNG, less revenue would be recovered from LNG sales, which might suggest that a price higher than 40 $/GJ would be needed. Of course, an even higher price would lead to less volume and potentially less revenue to recover the terminal costs. This is the "death spiral" effect in action, but for something that isn't yet alive.

2024 is not 2028

The report's main conclusion is that forward-looking decisions should only be made through a forward-looking lens. What was the best option for 2024 is unlikely to be the best option for 2028.

[5] The "undo changes" scenario shows a system with the "contingent storage" and "unlimited Rankine" changes reversed. It shows that prices would be ~16 $/MWh higher without both of those changes to the system.

1.1 What happened in 2024?

2024 wasn't a particularly dry hydrological year for power generation. Rather, the system likely found itself low on energy in the middle of winter due to inaccurate information leading up to the start of the year – both the availability of gas, and the likelihood of the Tiwai smelter exiting at the end of 2024.

1.1.1 Not a dry *year*

A common narrative for the high prices in 2024 was that it was a "dry year", but this is not entirely accurate.

Figure 3 - Modelled 2024 national hydro storage trajectories

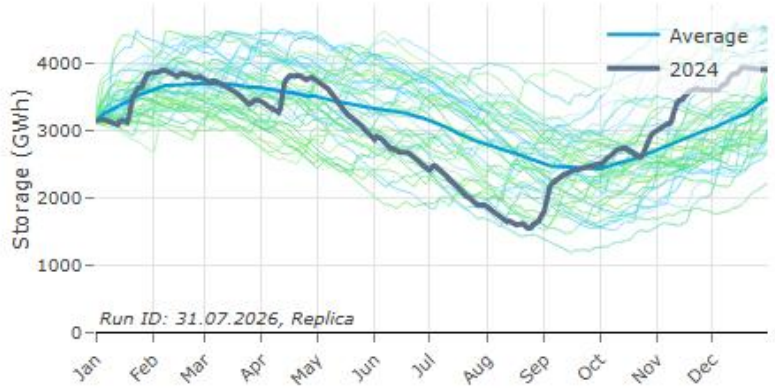


Figure 3 shows our modelled storage for 2024 with a range of historical weather (including inflows, wind and solar generation). While storage with 2024 weather was certainly low in August, it is not the worst possible year. Bearing in mind that actual outcomes can be worse than any historical sequence, it would be inaccurate to say that 2024 was exceptionally dry.

However, New Zealand doesn't have a dry *year* problem, but rather a dry "few months" problem[6] and the three months from May to July in 2024 did have very low inflows. Nevertheless, these months were "only" the 3rd to 5th driest such sequence on record,[7] and so they could have been much worse.

Figure 4 - Historical national hydro storage

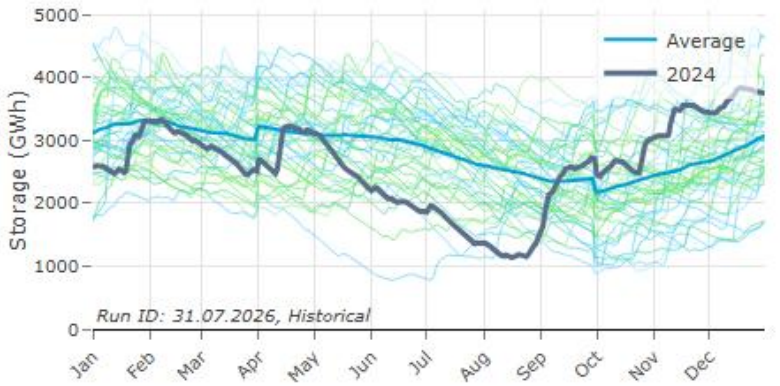
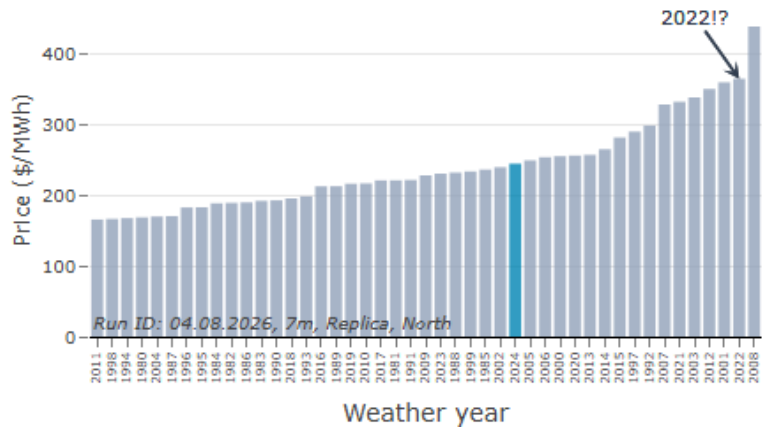


Figure 4 shows *actual* historical storage compared to other years, and, unlike inflows, 2024 hit a record low. Record low storage without record low inflows shows the dire situation that New Zealand was in.

[6] This is a key point we discuss later when considering the practicalities of LNG import.

[7] Depending on whether potentially unreliable early 1930s data is included.

Figure 5 - Modelled mean prices for first 7 months of 2024, across all weather years



The finding that 2024 was dry, but not that dry, is also supported by modelled prices across the different weather years – i.e., re-running 2024 with different historical inflow sequences as well as the inflows that actually occurred in 2024. Figure 5 shows mean prices for the first seven months of 2024. This is the period before the inflows arrived, and spot prices collapsed.[8]

While 2024 was a worse than average year in terms of weather, it was nowhere near the worst possible year on record.

An alternative interpretation of the weather in 2024 is not that we were unlucky, but rather the exact opposite. We reached record low storage without exceptionally dry weather.

Had we had the weather of 2008 or 2001, outcomes could have been much worse.

[8] Note that this approach (stopping the analysis just before a large inflow event in the year) would make any year look relatively "more dry" than stopping at a random point.

2022?!

Even the weather from 2022, just two years earlier than 2024, would have resulted in much higher prices. Fully reviewing 2022 outcomes would be a large undertaking, but 2024 was different primarily because:

- The first three quarters of 2022 had 16 PJ more gas production. Were this all converted to electricity through a combined cycle gas turbine (CCGT) this would provide ~2,000 GWh of energy. Of course, not all this gas would have been available for electricity generation, because demand from other sectors was higher. For example, 6 PJ more gas was used for chemical production (primarily Methanex); nevertheless, significantly more gas was available for electricity generation. This was reflected in spot gas prices for the first three quarters of 2022 being ~30% lower than the equivalent period for 2024.
- National storage (gas and hydro) was about 460 GWh higher at the start of 2022. We look at this issue more below.
- Demand for the first 7 months of the year was ~600 GWh higher in 2024 than previous years.

1.1.2 Short-term energy management leading into winter

The EA's report concludes that generator behaviour during the crunch time of winter 2024 was consistent with market fundamentals and a prudent operator. We don't disagree with this conclusion, but we did not directly address that question.

Instead, our review looked at market behaviour further back, and we come to an alternative conclusion. We find that, with the benefit of hindsight, the optimal market outcome would have been to hold storage higher leading into winter. However, achieving this "perfect hindsight" outcome was unrealistic to expect of parties at the time, because they were hindered by imperfect market information.

At least four areas contribute to our conclusion about imperfect market information:

1. Gas supply

New Zealand's declining gas supply is a well-documented phenomenon that we will not rehash here. However, equally important is the lower *than expected* gas supply, as this will lead to operators holding lake levels lower than is prudent. If the assumption is that gas will be available to provide energy in the future, then there is less need to store energy (i.e. water) now.

It's likely that market participants thought gas supply would be materially higher in winter 2024, or that it would be less difficult to divert gas from other users. The projections from the gas producers at the start of 2024 indicated production for 2024 that was 16% higher than they actually produced, and the producers' 2023 projections for 2024 (released in mid-2023) were 42% higher than actually transpired.

2. Demand growth

Demand for the first seven months of 2024 was ~600 GWh higher than previous years. While some demand growth could have been expected, forecasting exactly how much is difficult, and it is partly weather dependent. Higher than expected demand for the first half of the year would lead to lower storage.

3. Coal stockpile

Low coal reserves were clearly a factor in market outcomes in the middle of August. Genesis came within two weeks of running out of coal for the Huntly power station and this was one of the key triggers for the extreme prices seen.

However, it's unclear to what extent the finite coal stockpile factored into market decisions at the start of the year. It's possible that this was not properly flagged as a supply risk when assessing the value of water due to market expectations about gas supply.

4. Renewable generation build

Contact Energy's Tauhara geothermal plant was originally intended to be commissioned early Q1 2024, but it slipped to much later in the year.[9] This is a large amount of missing energy. For every month that Tauhara was not operational, more than 100 GWh of energy had to be sourced from elsewhere. So, a three-month delay results in 300 GWh less energy available to the system.

In addition to Tauhara, Meridian Energy's Harapaki wind farm was expected to be commissioned in June, but slipped to later in the year.[10] A month of Harapaki generation is about 50 GWh.

These four effects led to a reduction of the supply/demand balance by many hundreds of GWh compared to what was expected.

Information disclosure vs genuine market uncertainty

Most of the effects listed above are due to genuine uncertainty about how the future would eventuate. However, to the extent that it was possible, wider disclosure of market conditions could have led to better outcomes.

Modelling results

Our model held hydro storage about ~200 GWh higher going into winter, and this led to less extreme outcomes in the middle of winter.

However, our model used real gas supply, demand and generation build, so it is not fair to compare it to reality. A better interpretation of our modelled result is that if parties had better information about the future system they would have held lake levels higher going into winter.

We could redo our modelling with the assumed future gas supply changing during the year. This would be a moderately sized change to the model, and we have not done this. It would certainly lower water values (leading to lower storage and perhaps matching reality closer), but it's not clear to what extent.

How far back?

We started our modelling at the start of 2024, but storage at this point was already below average, suggesting that storage could have been held higher earlier. It's possible that the lower storage was the result of a tight supply/demand balance, but, perhaps counterintuitively, this should not be

[9] Tauhara began meaningful production in late May, but had typical commissioning outages and teething problems.

[10] It's difficult to give an exact date because wind farms are brought online in a staged fashion. Individual or batches of wind turbines are energised as they are completed.

the case. While it is costly to fill up the lakes over summer when supply/demand is tight, it is much more costly not to do so.

Extended Huntly unit 5 outage in 2023

Huntly unit 5 (Genesis's CCGT unit, also known as "e3p") suffered a major equipment failure in mid-2023, and was not returned to service until January 2024.

With Huntly unit 5's outage, TCC (Contact's CCGT unit) was called upon more often, and less efficient OCGTs were also used more. This will have led to lower storage leading into 2024.

We have not explicitly modelled this effect, but some simple calculations suggest that 100-200 GWh of energy was "wasted" by burning gas in less efficient units. This explains some of the lower starting storage in 2024, but probably not all.

1.1.3 Longer-term supply demand balance

The underlying reason for high prices in 2024, which can sometimes be overlooked, is that generation build had not kept up with need.

Although demand growth had been minimal over the past 15 years, the increasing cost of thermal generation meant that there had been meaningful growth in the need for non-thermal generation.

Our modelling indicates a mean price across all weather years of ~200 $/MWh for 2024, well above the long-term cost of new entry.

There were many contributing factors to this problem, which we briefly cover below. Fully unpicking each of these factors is a significant undertaking, and not the focus of this report.

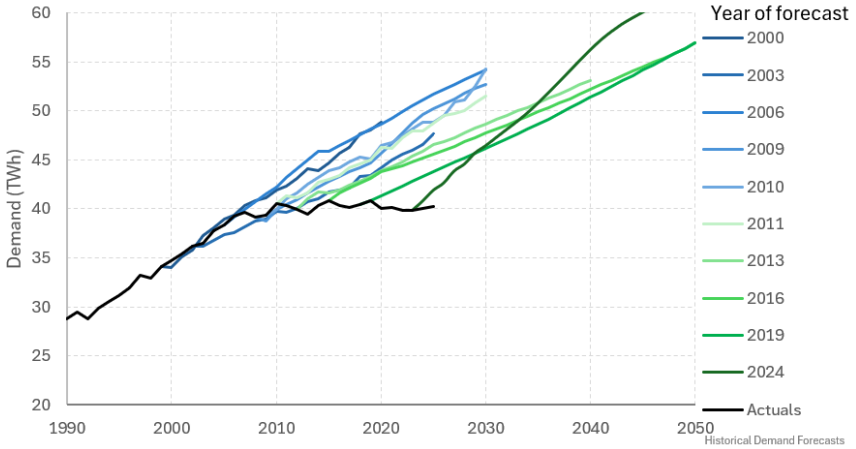
Gas supply uncertainty

We already discussed gas supply uncertainty in the short-term section above. However, gas supply disruptions extend back to 2019 when output from Pohokura was first reduced. 2025 was the first year since then when gas supply was not materially lower than projected at the start of the year by the gas producers.

This continual significant over-projection of gas supply (and consequent under-forecasting of gas prices) made it difficult to invest in renewable energy to fill the gap left by missing gas generation.

Demand uncertainty

Figure 6 - Official demand forecasts



Forecasting demand growth accurately has been challenging since 2008 and official demand forecasts from MBIE have continually been overly optimistic.

Investing in generation in this environment is challenging. Although actual demand turning out lower than forecast demand should lead to **over**-investment in generation, rather than under-investment. Perhaps, after almost two decades of over-forecasting, parties are wary of investing on the basis of expected demand growth, and instead have waited for actual demand growth.

Additional uncertainty around Tiwai exit

Rio Tinto was threatening to shut down the Tiwai Point aluminium smelter for years prior to signing a 20-year contract in May 2024, and uncertainty

around its future was a key factor in market decisions in the years prior. For example, Transpower's base case assumption for its 2021 security of supply assessment (SOSA) was that Tiwai would exit, and for its 2022 to 2024 SOSAs it had Tiwai exit as one of the key sensitivities.

Had Tiwai exited, this would have caused a major oversupply of generation and a consequent collapse of electricity prices.

Any potential generation project would have to weigh in the chance of this happening on its expected revenues, so it's not surprising that there was suppressed investment while this uncertainty existed.

Lack of institutional momentum

The 2010s saw minimal new generation build due to sluggish demand growth and flat gas prices.

This led to downsizing of generation development teams at major large generator-retailers ("gentailers") and lapsing of resource consents to build new generation.

Redeveloping institutional knowledge and updating consents is a time-consuming process and potentially contributed to a sluggish response to the need for new investment.

Market power

Many market commentators speculate that the lack of investment is due to the gentailers exercising market power to keep wholesale prices high.

We do not offer an opinion on this topic, except to note that in our opinion the slow build rate could be fully explained by the previous factors.

1.2 Market initiatives – 2024

In response to 2024, many initiatives have been proposed to help with the "dry year" problem. This section implements some of those solutions for 2024 and assesses what the outcome would have been. The primary metric we have presented here is price, although many other market outcomes are modelled, such as calls on Tiwai response, thermal utilisation and demand response.

The scenarios we considered are:

- Easier access to contingent storage at Pukaki,
- Entering the year with mean storage,
- Additional gas supply – two scenarios are tested here,
- More gas storage,
- LNG import,
- Higher renewable build,
- Unlimited availability for the three Rankine units.[11]

Note, this is not an exhaustive list of possible initiatives. For example, we haven't assessed the effect of:

- additional diesel storage and diesel generation capability at Marsden Point,
- dual-fuelling some of the Taranaki-based peakers with associated diesel storage and delivery,
- additional long-duration industrial demand response capability,
- improved ability to trade Methanex gas entitlements to power generation during a dry year,

The purpose of the selected scenarios is to understand the general nature and scale of altered market outcomes had the scenario being considered been in place for 2024. Note that what is best for 2024 may not be best for 2028 (and beyond).

1.2.1 Scenario analysis

Our modelled scenarios include many proposed initiatives that would improve dry year outcomes.

Up to this point we have focused on what happened in 2024. From this section on, results are presented on one of two bases, and we label which applies in each case. "2024 weather" means a single run using the weather that actually occurred in 2024 – inflows, wind, solar and temperature-driven demand. "All weather years" means outcomes across the 45 historical weather sequences our model runs, usually summarised by the mean. The two answer different questions – what happened in 2024, and what to expect on average – and forward and hedge prices should be compared to the second. We will initially look at 2024 with 2024 weather scenarios.

When reviewing these results, it's important to remember that 2024 was a very different system from what we have in 2026, and what we will have in the future. Many initiatives that are planned would have been very useful *in 2024*, but that doesn't mean they will be as useful in 2026 and beyond.

Easier access to contingent storage

In the easier access to contingent storage scenarios we remove the concept of "contingent storage" for Tekapo and Pukaki and treat all available storage identically. This allows ~770 GWh more storage in these lakes. Contingent storage can be used without a penalty (and is in 6 weather years). For reference, the reduction in demand from Tiwai in winter 2024 saved an estimated 330 GWh of energy.[12]

[11] Only two Rankine units were available for the first six months of 2024, and coal supply was a constraint in winter.

[12] https://www.ea.govt.nz/documents/7159/Review_of_winter_2024_jnOSQfc.pdf

Entering the year with mean storage

We also look at a hypothetical scenario in which we started 2024 with mean 1st January 1980-2024 hydro storage in all modelled lakes. This results in about 550 GWh more storage than the base case.[13]

We didn't do the same for gas storage, as there is much less historical record, although the starting storage of 5 PJ was slightly less than the 5.3 and 5.9 PJ from 2022 and 2023 respectively.

Additional gas supply

We look at two additional gas supply scenarios. In the first ("More gas"), we allow 30 TJ/day extra gas supply for the electricity system. This is roughly enough to run a CCGT at 50% capacity, and for the first 8 months of 2024 supplied 6.5 additional PJ (roughly equivalent to ~900 GWh if run through a CCGT). This brings gas supply up to about the level of 2020.

In the second ("Low Gas Price"), we also drop the base gas price to 10 $/GJ. This is consistent with market expectations a few years ahead of 2024, when generation investment decisions were being made for 2024.

More underground gas storage

We also modelled a scenario with additional underground gas storage – 15 PJ maximum storage rather than 7 PJ, with 130 TJ/day deliverability rather than 65 TJ/day. We assumed that an additional 7 PJ of gas would be stored at the start of the year.[14]

Similarly to the mean storage / easier access to contingent storage scenarios, the more storage / more gas supply scenarios are related. Note that although 7 PJ of additional gas is available, the larger gas storage is not run down as low, so only ~4 PJ of additional gas is actually used in this scenario.

LNG

This is a somewhat unrealistic scenario in which we allow unlimited gas supply at 25 $/GJ to simulate supply from LNG. This is "somewhat unrealistic" because in practice gas supplied by LNG import would not be unlimited and available-on-demand due to practical delivery constraints. It would also not necessarily be 25 $/GJ, but instead could be higher or lower depending on the international LNG price, New Zealand's ability to access LNG at the international price on short notice, and how import terminal costs are ultimately paid for.

Higher renewable build

This scenario is meant to simulate a system in which there was more certainty about demand growth in the early 2020s, and better knowledge about the coming decline in gas production, which would have supported more investment in generation. Speculating on exactly which projects might have been built in this counterfactual is imprecise, but we assume that these projects would have been available for 2024:

- Kaiwera Downs 2. This wind project reached FID the week after the announcement of the long-term Tiwai supply contract. For this scenario, we assume that had Tiwai exit not been a risk, Kaiwera Downs 1 (completed in 2023) would have also included Kaiwera Downs 2.
- Te Huka 3 and TOPP2. These small-medium geothermal projects were completed in late 2024-2025. It's possible that they would have been brought to market sooner in a world with more certainty around Tiwai remaining, and better knowledge of decreasing gas production.

This amounts to an extra ~1350 GWh/yr of generation, or ~27% of Tiwai demand.

[13] The Electricity Authority also found lower than mean start-of-year storage but calculated a lower value. It's likely they used a different period for calculating the mean. Ultimately, the mean isn't actually the correct comparison, which is what it "should" have been based on H2 2023 inflows and system state. A more stressed, higher renewable system should have higher lake levels on average. Nevertheless, the mean is a reasonable comparison point.

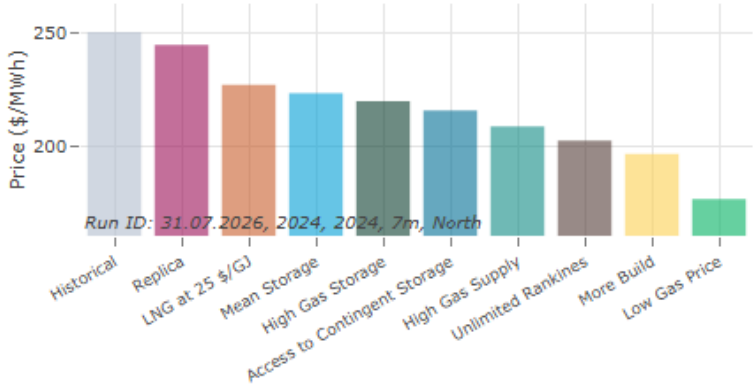
[14] As an aside, were the larger storage to be empty, it would actually *raise* prices slightly. The "gas value" at 5 PJ out of 15 PJ is slightly higher than at 5 PJ out of 7 PJ, because there would be negligible chance to overflow.

Unrestricted three Rankine units

In this scenario, all three Rankine units can operate at maximum output, and we ignore any coal fuel constraints. While this is unrealistic (as some maintenance outages would be required) it is a useful “best case” scenario for Rankine availability.

1.2.2 2024 price results

Figure 7 - Modelled annual prices (2024-with-2024-weather hindcast)



As can be seen, our ”Replica” (the base case scenario without any of the additional options) price is very close to the actual ‘Historical’ price. This provides confidence that the model is a reasonable reflection of how New Zealand’s electricity system operates.[15]

Figure 8 - Reduction in price for all scenarios (2024-with-2024-weather hindcast)

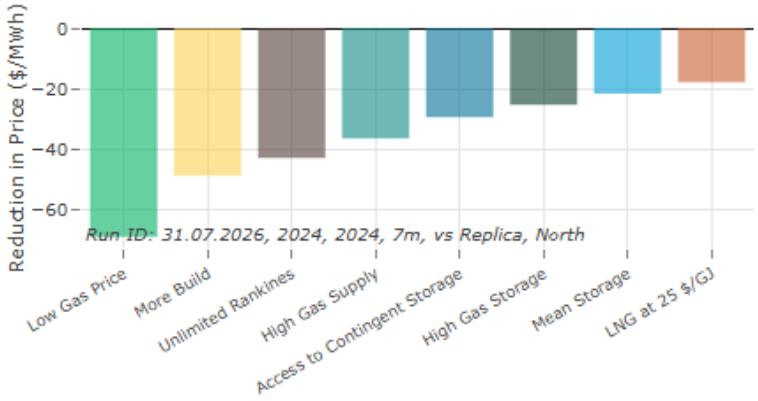


Figure 7 shows outcomes across the different scenarios for the first 7 months of 2024. Figure 8 just shows the *reduction* in price for each of the scenarios relative to our “Replica” scenario.

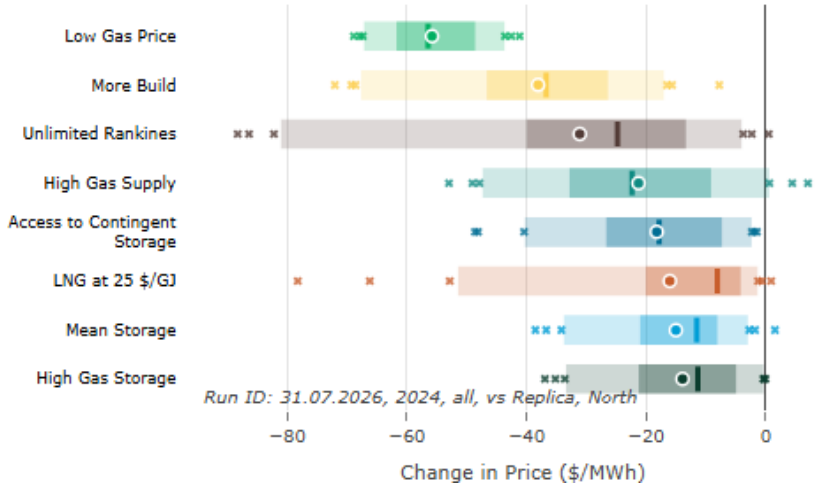
The largest impact scenario is the “plentiful gas” scenario. 30 TJ/day of supply at half the base case price drops price below 180 $/MWh. The “more generation” scenario is the next most impactful. A moderate amount of new generation would have made a very large reduction in prices in 2024.

In 2024, the LNG scenario is one of the least impactful options, but had the weather been much worse it would have had much higher relative benefits.

The next graph shows this effect – while the previous two graphs show results from only the “2024-with-2024-weather” analysis, it shows outcomes across all weather years and the results are more nuanced.

[15] The Appendix below provides more analysis on this topic.

Figure 9 - Price outcomes across all weather years



The distribution of outcomes across all weather years is shown here. The dot shows the mean outcome, while the vertical line in the central box shows the median outcome. The darker shading shows the 25th-75th percentiles, while the lighter shading is the 5th-95th.

Price formation for electricity forward prices

Forward electricity prices account for a wide range of potential weather outcomes. A forward electricity price of 125 $/MWh (roughly the current 2028 Otahuhu price) does not mean that the market thinks that the price will be 125 $/MWh. Rather, it indicates that across all the different possible weather conditions (e.g. hydro inflows, solar insolation, temperature driven demand) the expected mean price outcome will be about 125 $/MWh. The middle dot in Figure 9 shows our expected mean price impact across "weather years", so it should show roughly the impact on hedge prices.

There is some speculation that forward prices also include a "risk premium", meaning that they are priced above the expected spot price. Concept has found no evidence that this is the case, although we discuss this point further below.

'Low Gas Price' has by far the largest impact of the scenarios, followed by 'More generation'. These scenarios reduce prices significantly in all weather years, because they always provide more energy. On the other hand, some of the other options have minimal effect some years.

LNG is the prime example of this. It has a low average (mean) benefit across the range of possible weather, but a very large maximum benefit in the worst years. It is only useful during dry years, but the unlimited nature of LNG (as modelled) is heavily called upon when it is really needed. A similar pattern can be seen with the Unlimited Rankines scenario although not to the same extent.

Note that this analysis uses a 25 $/GJ price for LNG, which won't meaningfully contribute to recovering LNG import capital costs. Similarly, the "Unlimited Rankines" scenario doesn't explicitly account for any capital costs associated with maintaining three Rankine units.

Coal vs gas

Both the Unlimited Rankine and LNG scenarios provide an "expensive, on-demand" energy supply source. With our inputs for 2024, the cost of running a Rankine unit on coal is slightly lower than the cost of running a CCGT on LNG (and much cheaper than running an OCGT). This is the main reason for the much higher average benefits from the Rankine option.

The relative prices of the electricity from these two fuels in the future will change and this could affect the relative merit of either option. It's hard to predict exactly which option will be cheaper, but carbon price, international fossil fuel prices and capital investment requirements will affect the most economic outcome.

1.2.3 Additional comments on 2024 results

LNG

The LNG scenario has lower prices for the modelled 2024 year. This is despite the fact that very little LNG is actually used by the model.

Throughput vs energy supply

LNG can be used in the model for two different purposes.

- Firstly, it can provide throughput on a day to allow gas-fired generation to operate for longer over the peaks. Effectively it is providing “capacity” support for the system. This sort of service could also be provided by increased throughput from underground gas storage at lower cost.
- A very different use for LNG is to provide energy to the system. When used for this purpose, significant quantities of LNG are burned to provide ongoing energy to the system due to low hydro and local gas storage. No like-for-like alternative exists for this service.

In 2024, our modelling suggests that LNG would have only provided throughput support, and only on a handful of days.

Figure 10 - Gas storage with LNG

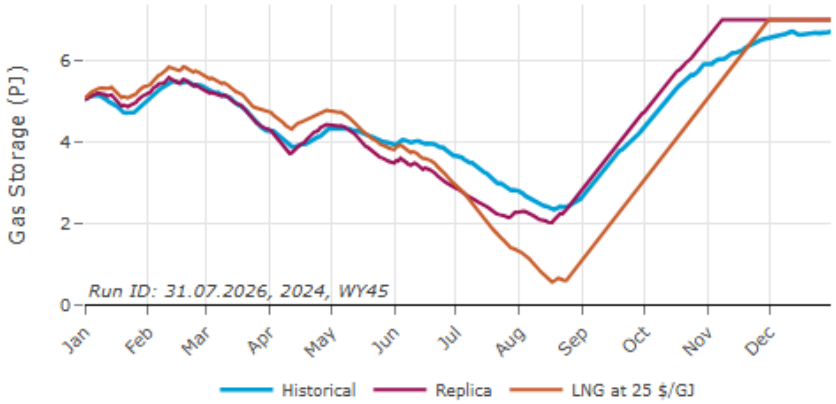
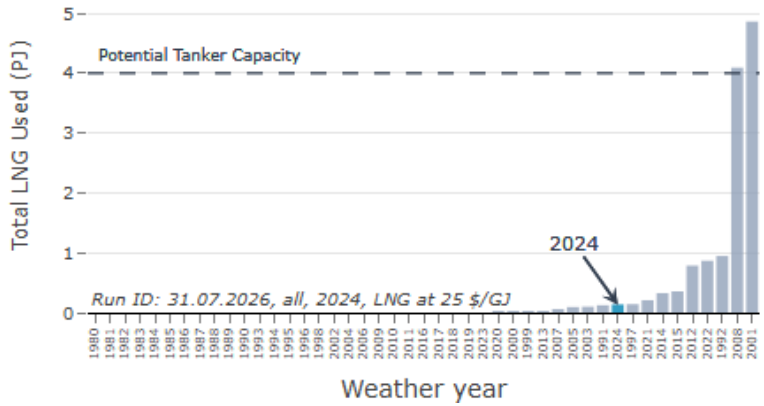


Figure 10 shows underground gas storage for our modelled ‘base case’, what actually happened (‘Historical’), and the LNG scenario. In our modelled LNG scenario, local gas supply didn’t run out, meaning that LNG was never called upon for energy supply.

[16] A very simplified example: if there’s a 50% chance of needing to run coal in the future for energy and a 50% chance of spilling, then the water value should be 50% the cost of coal generation.

Figure 11 - LNG used across weather years



Annual LNG usage across all modelled weather years is shown in Figure 11. 2024 was one of the handful of years in which a small amount of LNG was used to provide throughput. Given the binary nature of LNG supply (either we call upon a tanker or we don’t), these small quantities of modelled LNG use seem unrealistic.

On the other hand, in 2008 and 2001 LNG was used to provide energy, and accordingly the quantity of LNG used was much higher – comparable to the size of a small tanker.

Value of LNG as an insurance product

The graphs above suggest that only a very small amount of LNG would have been called upon in 2024. However, the modelled price is appreciably lower despite this.

This is because even when not used, LNG can lower prices since it is available to be used *if needed*.

Water values are set by the cost of the probability weighted alternative resource.[16] The LNG modelling has the option to call upon extra gas if

needed, which will reduce water values, allowing market participants to use water more freely.

By this mechanism, having the *option* of expensive, unlimited gas, even if it is not actually called upon, lowers wholesale prices. We refer to this as the “insurance effect”.

Unrestricted three Rankine units (“Unlimited Rankines”)

In our base case, we replicated the outage profile of the Rankine units and implemented a constraint on the amount of coal that could be used at any one time.

The Unlimited Rankines scenario ignores these realities and assumes 100% uptime for all three units. This is unrealistic, but serves as a useful bookend for possible outcomes.

This scenario has a very large reduction in price. It benefits both from the insurance effect described above for LNG, as well as actually providing additional generation. Modelled costs for running a Rankine unit on coal are lower than using LNG for generation.

Figure 12 - Coal generation[17]

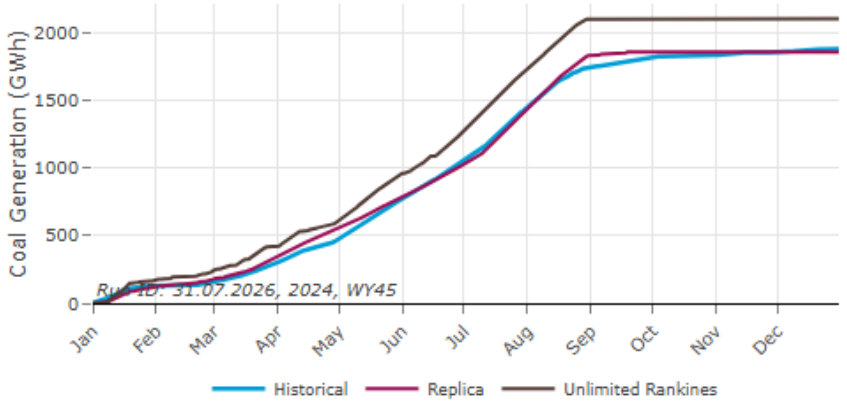


Figure 12 shows coal-fired generation through 2024. Our modelled replica case usage has been tuned to match historical behaviour.

Our Unlimited Rankine scenario produces ~330 GWh more generation over the year.

Easier access to contingent storage

Our easier access to contingent storage scenario shows a large reduction in price. It’s important to distinguish between the benefits in the first year that contingent storage is available and a long-term benefit.

Benefits in the first year (what is shown in sections of this report that use 2024 weather and 2024 starting storage) are high, because genuinely additional energy has been added to the system.

However, once the system is in a steady state, and contingent storage has been used in previous years, the price benefits are much lower. This is because additional storage does not provide net energy in the long run – if Lake Pukaki is drawn down it must be filled up again. Nevertheless, more storage capacity allows for less spill and waiting for longer before calling

[17] We have assumed that all Rankine output is coal fueled. The vast majority of Rankine operation was coal fueled in the first 7-8 months of 2024, but not 100%, so this is a slight simplification.

upon thermal generation, and these are real benefits, which leads to the price drop.

More renewable build

This scenario posits that generation investment was delayed in the late 2010s and early 2020s, which led to systemic undersupply. That statement is relatively uncontroversial, but more controversial are the reasons for it.

In Concept's view, uncertainty surrounding the exit of the Tiwai smelter and overoptimistic gas supply projections were mostly to blame, although we acknowledge that there is uncertainty around the scale of effect this had on generation investment decisions.

Proving the reason for underinvestment is difficult, and has been the subject of much debate.

While we are reasonably confident that investment was delayed, it's hard to know how much faster investment would have been in the counterfactual. In this scenario we assumed that ~150 MW of wind would be brought forward by 3 years, and ~100 MW of geothermal by two years, but that was by assumption rather than through any rigorous reasoning. As set out above, the extra generation would account for ~27% of Tiwai annual consumption.

Bringing this amount of investment forwards doesn't get our 2024 scenario back to balanced – it would still have been an undersupplied system, just less so than it was. As such, it is possible that had the market had perfect foresight of Tiwai's decision and actual gas deliverability, the level of build leading up to 2024 would have been greater than in this more-renewable-build scenario.

1.3 2028 modelling

The previous section was a relatively in-depth analysis of 2024 outcomes. While that is interesting, it has limited relevance to what we should do today to prepare for the future.

In this section, we provide some limited material from our 2028 modelling. We don't provide prices as they are part of our full price forecast report – but we note that our 2028 prices are currently broadly similar to the current ASX forward curve.[18] Instead, we show *changes* to prices for 2028 that might originate in some of our scenarios, analogous to Figure 8 and Figure 9 above.

We also show 2024 and 2028 thermal utilisation. We are in a rapid "de-thermalisation" period, and the differences are stark.

1.3.1 The system in 2028 is very different from the system in 2024

Some of our scenarios from 2024 weren't modelled in 2028, because they are already implemented in the base case. These are:

- Easier access to contingent storage. Meridian has recently received approval to use Pukaki contingent storage more freely. We assume that Pukaki contingent storage is now treated exactly the same as other Pukaki storage. We also assume that Tekapo storage can be used freely.
- Unlimited Rankines. Genesis's HFO provisions provide much more certainty on the operation of Rankine units and the coal stockpile. We now include three Rankine units in our base case.[19]
- More generation. 1,100 GWh of wind, 2,500 GWh of solar and 1,800 GWh of geothermal will have been built by the end of 2028. In effect, our base case now includes and exceeds the "more generation" case from 2024.

1.3.2 How would prices change with different market initiatives?

This section shows modelled price **changes** for the 2028 system.

We present results on both bases: "2024 weather", which uses the same weather and starting storage as 2024, and "all weather years".

The scenarios presented here are slightly different from the 2024 section above. As mentioned above, some of the scenarios from the 2024 modelling have already been implemented, so are incorporated in our 2028 base case.

We've also added in:

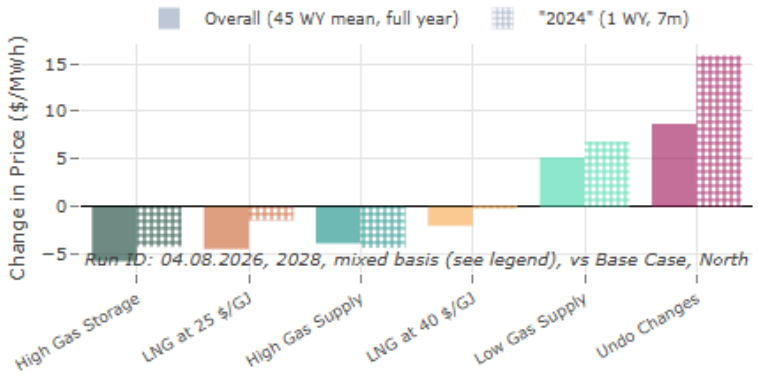
- a less gas scenario (with 20% less gas available for thermal generation) to complement the more gas scenario (20% more gas),
- an "undo changes" scenario, which reverses the changes to Waitaki storage access and Huntly thermal availability so that they remain as they were in 2024, and
- an LNG @ 40 $/GJ scenario that shows outcomes with a higher LNG price.

Figure 13 shows price changes on both bases – 2024 weather, and all weather years ("Overall").

[18] When the 2028 forward price was 50% higher earlier in the year they were not.

[19] Total output is limited by river heating limits in summer and forced outages.

Figure 13 - Change in modelled price for 2028



2028 with 2024 weather

These results show how modelled 2028 prices change for the first seven months of the year if we have a year with 2024 weather and starting storage. In this respect, it's comparable to the 2024-with-2024-weather analysis above.

The results are insightful:

- If we run the system with restricted Rankine availability and Waitaki contingent storage access, prices are >15 $/MWh higher. These two implemented changes have significantly improved the outlook for energy supply in 2028.
- LNG @ 25 $/GJ reduces prices slightly in this scenario, but when compared to the equivalent impact in 2024 (18 $/MWh) it is clear that these are two very different situations.
- LNG @ 40 $/GJ has even less impact. At this assumed price it is similar to diverting gas from other users.[20]
- A 20% increase or decrease in gas supply affects prices a reasonable amount. Note that the impact is asymmetrical – a decrease in supply leads to a larger increase in price than vice versa.
- We also considered a scenario with more gas stored at the start of the year (12 PJ), and this leads to a moderate reduction in price.

2028 across all weather years

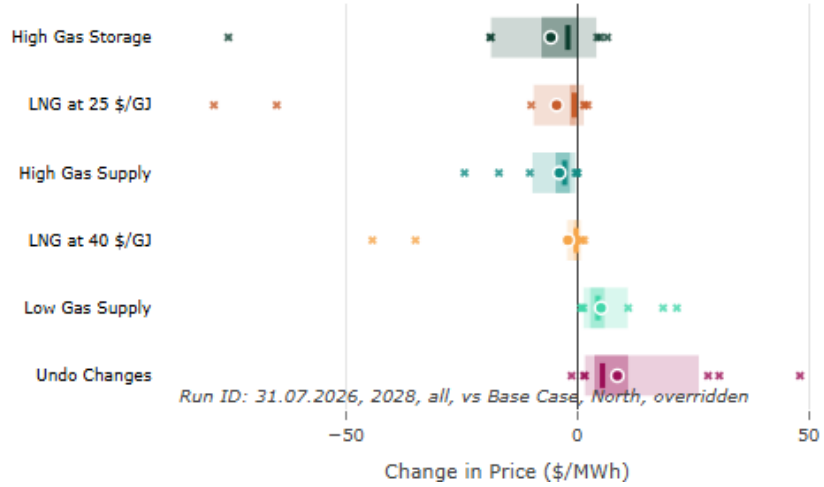
These results are broadly similar to the 2024 weather results, but have some interesting differences. The all weather year results are the best indicator of the effect on forward prices because they show the mean expected outcome, and not just the outcome for one weather year.

The "undo changes" result drops significantly, because of the contingent storage effect discussed above. More contingent storage is very useful in the first year (as modelled with 2024 weather), but is much less so over the long term (as modelled across all weather years).

Figure 14 shows the distribution of outcomes for 2028 across all weather years, using a box and whisker plot. The mean price changes in the box and whisker graph correspond to the mean "Overall" price changes in Figure 13.

[20] We assume Methanex will have exited by 2028, so diversion from Methanex will not be available. We still assume that some gas could be diverted from other gas users to electricity generation, although in much lower quantities.

Figure 14 - 2028 distribution of outcomes across all weather years



The most interesting feature here is the outlier results. LNG @ 25 $/GJ's mean reduction in prices is modest and similar to "more gas storage" and "more gas supply". However, the way the mean outcome arises is very different. LNG has very little effect in most years, but in two years (using 2001 and 2008 inflows), it drastically reduces prices.

It's not often called upon, but when it is, it is very useful and this has a meaningful effect on mean expected outcomes.

LNG @ 40 $/GJ has the same type of distribution, but even more extreme. It would still provide a meaningful benefit in extreme dry years, while doing basically nothing in other years.

More gas storage is similar, but only reduces prices in one outlier year (2001 inflows). Its effect on prices using 2008 inflows is much lower, because 2005, 2006 and 2007 were all drier than average and we use a chronological sequence of historical inflows across weather years. Gas storage had been successively drawn down each winter and was unable to fill back up in time for 2008. This highlights the difference between LNG, which does genuinely add energy to the system, and underground gas storage, which does not.

1.3.3 LNG findings

Risk premium revisited

One possible additional benefit of the LNG scenario is that it reduces prices during the highest price years. This would lower any "risk premium" that exists in forward prices.

Concept has seen no evidence that such a premium exists, but it is difficult to properly assess this effect. "Post-hoc" analysis comparing forward prices to actual prices is of limited use due to the effect of weather on actual prices. If it is "wet", then it looks like there was a large risk premium and vice versa.

We note that opinions on risk premium may have changed following the ~33% reduction in forward prices – but it's possible that the drop in prices is partly because of a real reduction in risk premium.

There has been speculation that the announcement of an LNG import facility has contributed to this falling forward curve. However, prices for 2027 (well before it would be possible to construct such a terminal) have experienced similar drops, which suggests this is not the case.

Cost impact

Our modelling assumed a price of 25 $/GJ for LNG. This level is consistent with international LNG prices plus a small margin, but significantly under-represents the price impact were LNG terminal costs to be recovered from LNG sales.

Using our modelled LNG consumption in 2028, a modest $75m/yr capital cost recovery would add, at least, an eyewatering 250 $/GJ on LNG price.

However, we have clearly observed the "insurance effect" of LNG import in our modelling, whereby simply having the option of LNG as a backup results in lower prices. This suggests that it may be appropriate to recover some proportion of capital costs from a centrally administered mechanism.

Developing a cost recovery mechanism that accounts for this insurance effect is difficult, but recovering none of the capital recovery costs from

LNG sales directly seems inappropriate and would lead to worse economic outcomes in the long term from the distorted price signals.

Our 40 $/GJ LNG scenario is intended to be a price at which a small but non-negligible amount of costs are recovered from LNG sales. At 40 $/GJ, much less LNG is used (and it has a much lower effect on electricity prices). Accordingly, with this lower amount of LNG used, a 40 $/GJ price may be too low, but an even higher LNG price would lead to even less utilisation.

This is an example of the well-known “death spiral” effect, except here it is applied to something that is not yet alive. “DOA spiral” may be a more accurate term.

Reality of insurance effect in practice

The “insurance effect” is logical and intuitive, but it relies on LNG being available when desired. Our modelling lets parties run lakes lower because they have the option to access 25 $/GJ gas on demand.

In practice, there will be long lead times on delivering LNG shipments. Concept is not an expert on this issue, but we understand ~four weeks is a reasonable timeline for fastest practicable delivery.

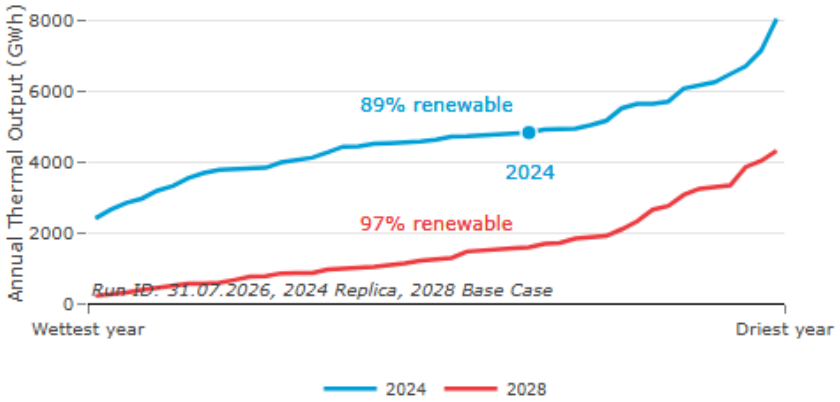
Four weeks is a very long time during a dry winter. We observed above that New Zealand doesn’t have a “dry year” problem, but rather a dry “couple of months” problem. Storage was above average in May 2024 and critically low by July 2024.

The assumption that parties would be more willing to run lakes lower only holds if by doing so they are confident of LNG arriving promptly if needed. This could be unrealistic, given the timelines involved.

1.3.4 Thermal generation

To further illustrate the changing nature of New Zealand’s electricity system, we show our modelled thermal output for the 2024 hindcast and 2028 across all weather years.

Figure 15 - Thermal generation



Thermal generation is forecast to drop by 67%. Thermal usage during the wettest years drops to less than 1,000 GWh. In these years, thermal is used for meeting demand peaks, not to provide energy. This is quite different from 2024 when, even in the wettest years, we still needed thermal generation to “top up the lakes”.

However, we still call upon significant quantities of thermal generation in the driest years in 2028. Our driest weather year in 2028 results in similar modelled thermal output as “2024 with 2024 weather” (shown by the blue dot).

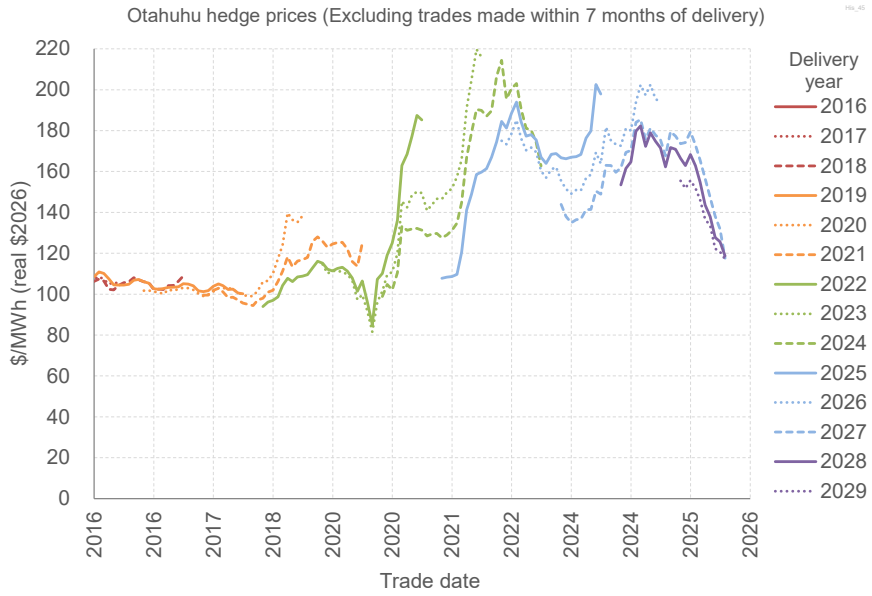
There is no such thing as baseload thermal in 2028, but the system still needs thermal to provide peak capacity and energy during dry periods.

1.4 ASX trends

Finally, we close by observing that our assertion that the underlying undersupply situation is abating is supported by movements on the ASX.

Figure 16 shows the trend of 2027, 2028 and 2029 calendar strip prices since the start of 2026. Prices for these three future years have fallen by ~34%, ~29%, and ~25%, respectively.

Figure 16 - Otahuhu hedge prices (excluding trades made within 7 months of delivery)



In Concept's view, this is the natural result of investment in new renewables "catching up". We have forecast a "balanced" system by 2030 for at least 18 months, and it appears the market is coming around to the same view, with the latest ASX prices for 2027 to 2029 being close to the LRMC of new renewables – i.e., the LCOE of wind or solar, factored by their respective firming costs to deliver a baseload profile.

Indeed, the extent to which renewable build is outpacing demand growth means there is a non-zero chance that the system may move into a situation of *oversupply*.

Appendix - Hindcasting using ORC

The remainder of this report dedicates a lot of time to reviewing how Concept's hindcast modelling compares to historical outcomes. Less technical readers may wish to end here, but it is important context for the analysis above.

This report was prepared using our model "ORC". ORC predicts how New Zealand's electricity system will develop over time and forecasts the prices that will eventuate in the market. For a given modelled future year, ORC is run across 45 possible 'weather years' using fully-coincident historical hydro inflows, wind flows, sunshine, and demand levels.

We reran 2024 using our ORC model. Such an exercise is insightful for verifying and reviewing the performance of ORC. If it can reasonably accurately replicate historical behaviour, then this suggests that it is providing useful information for the future. Everything in this section is a single run on 2024 weather – comparing to actual 2024 outcomes requires it. The all-weather-year results appear only in the scenario sections above.

When undertaking this hindcast, we set gas and hydro storage to their historical levels at the start of 2024. Other than this, we used as many endogenous calculations as possible. The purpose of this exercise is not to replicate 2024 through specifying all possible inputs, but rather to set the model up at the start of the year and let it run.

To this end, we didn't exogenously specify when the Tiwai demand response option was exercised by Meridian, nor did we exogenously specify when gas was diverted from Methanex. The latter decision means that our results for the last few months of the year are very different, but the first 7-8 months still provide a good period to compare.

This approach also allows us to rerun different scenarios (see later section), and see, for example, when (or if) the model indicates that we should have called upon demand curtailment at Tiwai. Exogenously specifying too many inputs would not allow us to properly simulate different scenarios.

Our one exception to this approach is thermal power plant outages. These can be critical to outcomes, and are relatively insensitive to whichever scenario we are looking at.

To assess performance of the model, we present many different graphs showing the outcomes in reality and in our model.

1.4.1 Daily prices

Figure 17 - 2024 daily North Island price

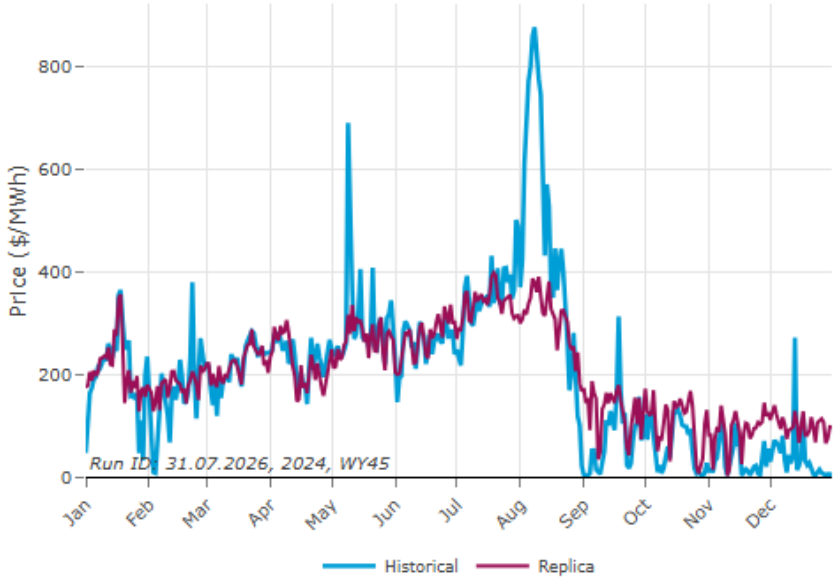


Figure 17 shows historical and modelled daily mean prices. From 1st January to 1st August, the modelled and historical mean prices were 240 and 249 $/MWh respectively. So, the level is similar until the start of August, although there are some notable exceptions.

Early year price drops

There are many days in the first three months of the year in which the modelled daily price is higher. The modelled price consistently stays above 100 $/MWh, while the actual price dropped below this often. It appears that our model had higher internal water values for this period than were implemented in practice.

May daily price spikes

Historical prices on some days in May were much higher. This is due to capacity related price spikes, which we didn't see in the model. We expect this is primarily due to reduced plant availability and plant commitment issues. We turn off our stochastic outages and implement some real sustained outages in the model, but not all. An improvement to our hindcasting would be to more precisely and comprehensively replicate historical outages. It's also possible that the scheduling process within the model isn't sufficiently disruptive to match the real-world challenges of scheduling plant.

End of winter price spike

A large source of difference is during August when historical prices rose to >800 $/MWh. Prices at this time were mostly set by offers on the Waitaki system. In early August, Meridian called upon the full demand response option from Tiwai and at the same time raised its marginal offers on the Waitaki to ~800 $/MWh.

Our modelling kept water levels higher going into winter, so levels were not so low at the start of August, and so our water value was not as high and we did not call upon the full Tiwai demand response.

End of winter price drop

As real prices spiked in August, our modelled prices dropped slightly. This is partly because our model has ~150 GWh more stored hydro at this time. However, partly it's because our water values suggest that by mid-August we are almost through the worst of winter, and inflows are just around the corner. Clearly the market in 2024 disagreed.

Gas glut period

As discussed above, our modelling doesn't include a long-term gas diversion contract from Methanex. Our modelling *does* include the option to divert gas from other users at a price of 40 $/GJ, but crucially, this is on a pay-as-you-go basis. There's no commitment to continue taking gas day after day if this option is called upon.

Because of this, although our modelling did divert some gas in the middle of winter in some scenarios, it didn't continue to after large inflow events in August. This leads to very large differences in outcomes for the end of the year.

Note however, that even without accounting for this additional contracted gas, our price collapses at roughly the same time, even if not quite to the same extent.

1.4.2 Price duration curve

Figure 18 - Price duration curve comparison for first seven months

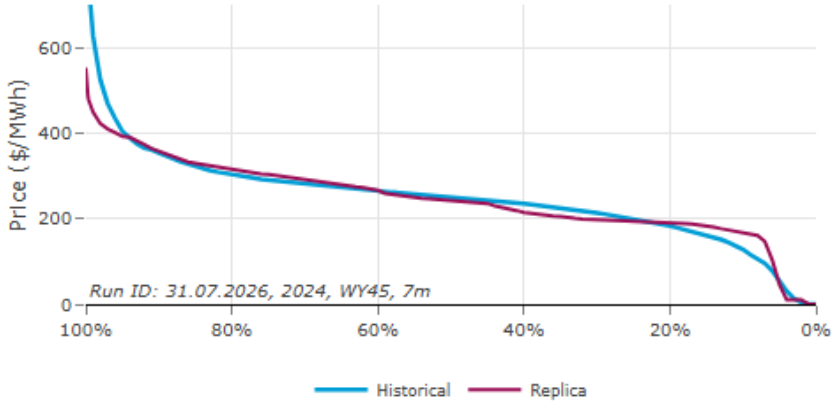


Figure 18 shows hourly price duration curves for modelled and historical prices. We only show the period up to August before historical prices jumped to 800 $/MWh.

The curves match reasonably closely, except for the top percentiles. We've covered why that difference occurs above when talking about the daily price spikes in May. Note that the very top of the curve (not shown) reaches >3,000 $/MWh for historical prices, while the modelled price doesn't exceed 700 $/MWh.

1.4.3 Monthly within-day price shapes

Our final way of looking at prices is the daily shape of prices, within each month.

Figure 19 - Within day price shape for March[21]

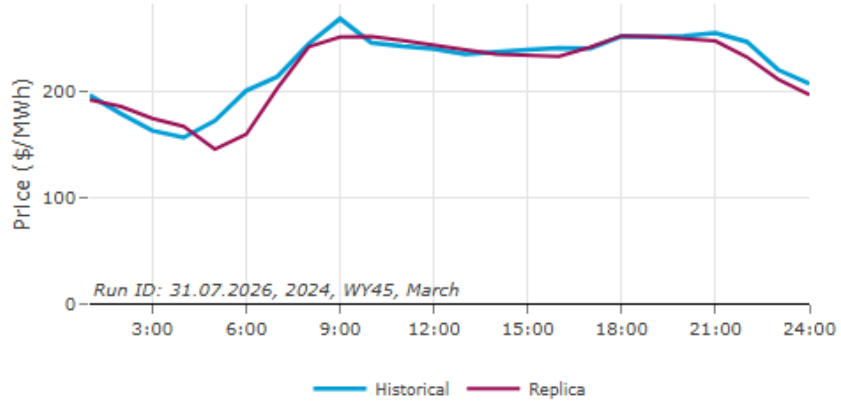


Figure 19 shows within-day shape for March. Modelled prices are similar during the day, but are lower overnight. There is a similar trend for most early months in the year.

Figure 20 - Within day price shape for June

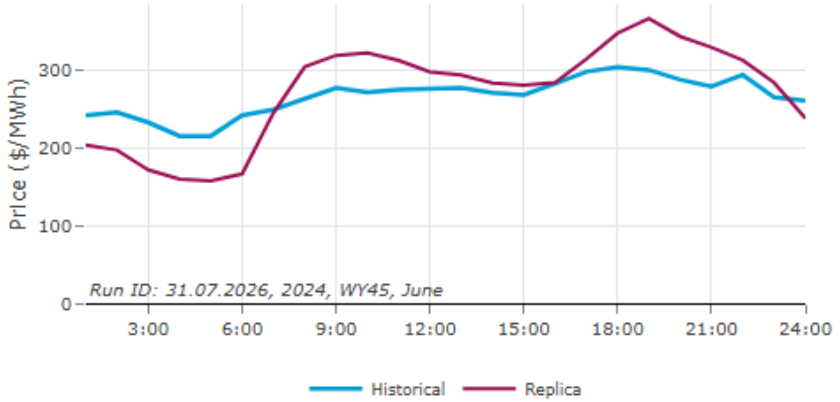


Figure 20 shows the same data for June, and the difference is more pronounced. Our modelled prices still have the clear diurnal shape, but historical prices have become even flatter, with minimal overnight drop.

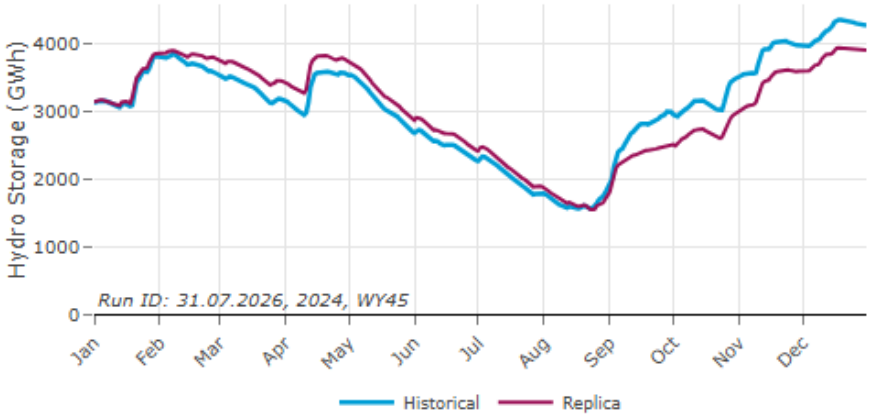
To a greater or lesser extent, our modelling almost always has higher "within day spread". An exception to this rule is when historical prices spiked above 1,000 $/MWh. This doesn't occur in our modelling, so a few very high-priced periods can make the within day spread larger on the days they occur.

1.4.4 National energy storage

We ran our model with the historical starting storage, both for hydro and gas. The two types of storage are shown below.

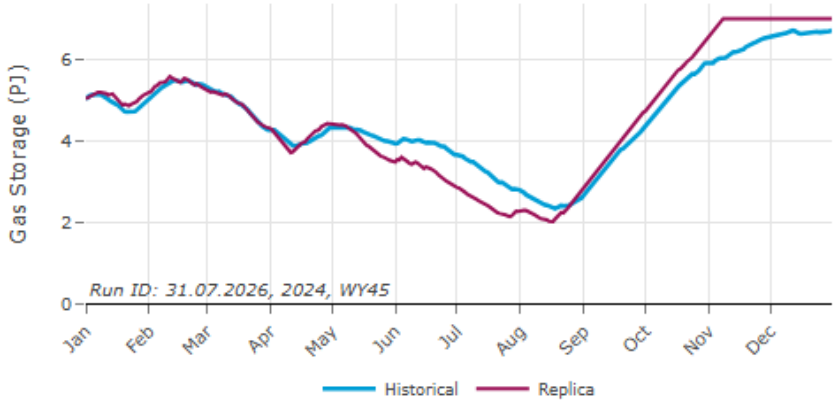
[21] We filtered days to only look at those that had mean daily prices within 20%. This is because the purpose of this section is to look at within day shape, rather than to compare the level of prices. A 20% filter is sufficiently relaxed to not excessively filter days.

Figure 21 - National hydro storage



Our modelled hydro storage tracks historical reasonably closely, but we appear to have higher water values in the first few months of the year. This means we have slightly higher storage going into winter (about 200 GWh higher in May), and so can call upon more hydro generation over the dry period from May to July.

Figure 22 - National gas storage



Our modelled gas storage tracks historical very closely until May, at which point it drops below.

This is partly because we assume a flat gas supply profile across the year, but in reality, it increased a little bit in winter.

Our standard gas supply assumption is for a flat profile over the year. Gas supply increases slightly over winter as production is optimised, but there's more demand from other users also. Our assumption with our modelling is that these more-or-less net out so that the within year profile is flat. This wasn't quite the case for 2024, but it was reasonably close.

Note both how our modelled gas storage refills at roughly the same trajectory as it did in reality, and also at about the same time of year. Even without a diversion from Methanex, there was ample gas, so both storage levels were determined by injection rate, rather than any shortage of supply. The timing of inflows and the signing of the agreement to divert gas from Methanex to other users was rather unfortunate.

Manapouri

Modelling Manapouri is difficult. It doesn't just have a maximum lake level but instead has more complex consenting rules that (to oversimplify) require the operator to try to get back below a target maximum lake level after a large inflow event.

We implement this by setting water value to $0 at the nominal full level but not actually enforcing a hard limit on storage until quite a bit higher.

This is relevant for the 2024 modelling as Manapouri spilled early in the year both in reality, and in our modelling.

Tekapo

When modelling Tekapo in 2024, we assume that the 220 GWh of seasonal contingent storage was not feasibly available (i.e. it was priced very high, similar to Pukaki's contingent storage). This is consistent with Genesis's description of a "shadow constraint",[22] and is consistent with Lake Tekapo never falling below 220 GWh while Genesis controlled its operation.

Note that this behaviour is likely to change as the restrictions around Tekapo contingent storage are relaxed, and we assume all of Tekapo is available for use in our future modelling.

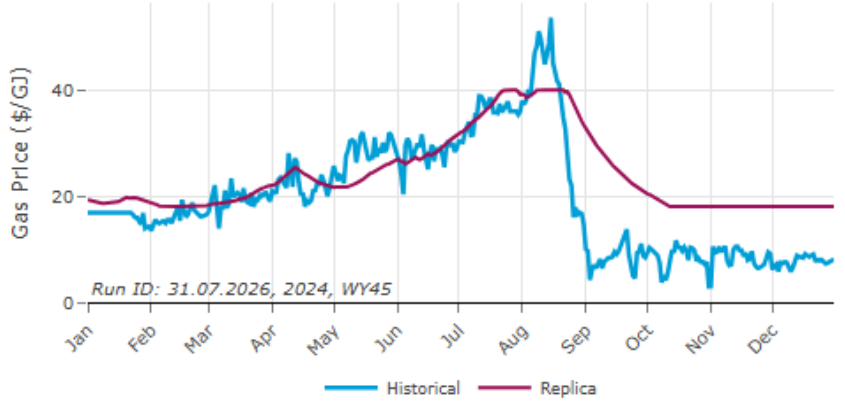
Coal supply

One key feature of our modelling is that we normally assume that coal supply is unlimited. In practice, this is not the case, and this was particularly important in 2024. Coal storage at Huntly dropped below 200 GWh in August 2024, only sufficient to power all three Rankine units for 10 days at most.[23,24] Ignoring coal supply issues would be an oversimplification.

Unfortunately, our model isn't set up to implement a "coal value curve". In lieu of a proper implementation, we restricted the amount of coal that one Rankine unit was able to burn at the start of the year, such that a similar amount of the coal stockpile was consumed. Full capacity from the Rankine unit is still available by supplementing with gas.

1.4.5 Gas price

Figure 23 - Gas price



As explained above, we set up the model and "let it run". One of the parameters that we could have used historical values for, but chose not to, is gas price. While it's tempting to use historical gas prices (and this produces improved outcomes), it would restrict analysis of alternate scenarios and not allow us to verify the gas pricing within the model.

Our modelled gas price tracks historical price very closely, until the start of August, at which point the historical gas price collapses. This is explained by the contracted gas diversion that we didn't model.

Note that we implement an exogenous diversion price of 40 $/GJ, meant to represent the cost of purchasing contracted supply from other users. The model doesn't actually call upon this gas diversion, although it's a very close thing.

[22] Genesis Energy, "Genesis Energy's submission on SOSFIP Review," letter to Transpower New Zealand, 4 November 2025, https://static.transpower.co.nz/public/bulk-upload/documents/Genesis%20Submission%20-%20SOSFIP%20Review%202025.pdf.

[23] As stated in the EA's winter 2024 review.

[24] And this is a best-case scenario, since coal at the bottom of the stockpile is lower quality.

1.4.6 Huntly gas allocation

One exogenous input we did specify was to limit the total gas that could be used at the Huntly station each day, in line with the observed average daily usage. Had we not done this, the model would have sourced much more generation from Huntly Unit 5 than actually occurred.

The model prefers to run Unit 5 because it has the highest modelled efficiency and, to the best of our knowledge, that matches reality.

However, Unit 5 was not always utilised to its full capacity while other gas units were operating. This is probably because of contracted gas supply agreements. Although in a frictionless world it would make sense to sell gas to Genesis and then buy the electricity, some generators may have simply burned the gas themselves.

1.4.7 Model verification conclusions

This analysis has highlighted some areas of similarity between our modelling and what actually occurred, but also some important differences.

Peak pricing outcomes

Our model doesn't predict daily average prices in excess of 700 $/MWh, but 2024 frequently had hourly prices above this level, up to 3,800 $/MWh. The reason for the higher prices is probably because of station outages and/or inaccurate commitment decisions. There was sufficient capacity in the system, but it was not available at the time leading to the supply shortage.

When running the model in "hindcasting" mode, we turn off stochastic outages, and instead implement long-term outages from Transpower outage data. This will miss some short-term outages, and may explain some of the differences. When we forecast future years with stochastic outages, supply constrained periods do occur when thermal units are unexpectedly unavailable.

Ultimately though, looking backwards provides limited information on how peak pricing will develop in the future. 600 MW of additional commissioned and committed batteries will be developed by 2028 and EV charging demand and counterbalancing demand responsiveness will continue to grow. This will rapidly change the peak pricing dynamic, and so historic outcomes are of limited use.

Within day shape

The model predicted higher within day price spread. This may be driven by assumptions about hydro minimum generation levels. The model predicts prices would drop more overnight, so we may be holding minimum hydro generation levels too high.

When modelling hydro flexibility, the tendency is to "over-optimise" outcomes and simulate excessively large swings in hydro generation. To avoid this outcome we intentionally moderate the amount that hydro varies from period-to-period, but perhaps we have overdone this.

Hydro storage levels

Modelled hydro storage tracks historical storage closely until mid-February, at which point the model keeps lake levels slightly higher. The model heads into winter with lake levels ~200 GWh higher.

However, when evaluating what this tells us about our modelling approach, it doesn't necessarily mean our model is *excessively* conservative when looking ahead. This is because:

- The model sets water values knowing how much gas would be available ahead of time. The model doesn't have perfect foresight by design, but this is one area where it is clairvoyant. We know that participant expectations of gas supply for 2024 were higher than what eventuated, so this might explain most of the difference, and would suggest that hydro operators were being appropriately conservative.
- Additionally, outcomes in 2024 might make future behaviour more conservative when it comes to valuing water – at least for a few years until memory of 2024 recedes. Given that our model is primarily a forward-looking tool, potentially incorporating higher risk aversion than was displayed in 2024 seems reasonable.[25]

[25] Any feedback on this issue would be appreciated.

One improvement to this hindcasting exercise would be to run the water value model with an inaccurate expectation of gas supply that evolves over the year. This would lead to lower storage going into winter and may lead to mid-winter outcomes that more closely mimic what occurred.

Gas supply module

The modelled gas price tracked real prices very closely until August which suggests that our approach of tying gas prices to gas storage levels is sound.

Gas storage tracks historical levels very closely at the start of the year but drops slightly lower during winter. Given the simplifications we make with gas supply, this is a positive result for verifying operation of the gas storage module.

Coal stockpile implementation

Our standard model doesn't track coal storage or implement a rising coal price as storage level reduces. We think this is a reasonable simplification for future modelling. Genesis's implementation of a "security stockpile" to support their HFOs[26] should provide more supply security and significantly reduce the risk of running out of coal.

[26] "Huntly Firming Options" are structured electricity swaptions giving other generators virtual access to Genesis Energy's Rankine units at Huntly Power Station, called on during dry winters/low hydro inflows to firm supply and ease wholesale price spikes.