Tekapo Power Scheme – electricity sector benefits

Report prepared for Genesis Energy Ltd

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Glossary

CCGT	Combined cycle gas turbine
ETS	Emissions Trading Scheme
MBIE	Ministry of Business, Innovation and Employment
MW	Megawatt
OCGT	Open cycle gas turbine

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Executive summary

Electricity sector overview

Regulation of the electricity generation sector is designed to encourage competition. At its centre there is a regulated auction-based spot market, in which generators make supply offers every 30 minutes. The generators with the lowest offer prices are selected to satisfy demand in each half hour.

Spot prices vary depending on the relative balance of electricity supply and demand at different times of the day and year. Prices also vary by location on the grid, reflecting the local supply/demand balance and the extent of network constraints and power losses which occur when electricity is transported on the grid.

The spot prices generated in the electricity market provide important information about the value of different types of generation, such as whether it has controllable output or not, and where it is located on the grid.

Electricity demand and supply

Electricity is vital in our daily lives. Many of the social and economic benefits we enjoy stem directly from technologies relying on electricity. Looking ahead, electricity is expected to become even more important as New Zealand moves to decarbonise the economy using renewable generation sources.

To meet its decarbonisation objectives, New Zealand will in future need to develop new generation sources at an unprecedented rate. Much of that generation will be from wind and solar power. Although these are very cost competitive, their output is subject to fluctuations due to weather, etc.

While batteries are expected to help in smoothing out much of the very short-term fluctuation in supply from these sources, they are not suitable for addressing variations which occur from week to week or longer. Other sources of flexibility will be needed. One of the most important is expected to be hydro generation that has access to stored water. This type of generation has the twin benefits of being renewable and controllable – both of which will be increasingly important as New Zealand decarbonises its economy.

National and regional benefits of Tekapo Power Scheme

The Tekapo Power Scheme provides significant national benefits to the power system by generating substantial volumes of 100% renewable electricity. In energy terms, the Scheme's average annual output (from both direct and indirect generation[1]) is sufficient to supply approximately 228,000 Canterbury households.

We calculate these benefits by determining the cost of replacing the full extent of services the Tekapo Power Scheme provides with the next best alternative – i.e. the cost of replacing the Tekapo Power Scheme in its entirety. If only a proportion of these services needed to be replaced, for instance due to a partial reduction in the output or flexibility of the Scheme, the costs of replacement would be lower. However, due to the large benefits the scheme provides as a whole, it is likely that the benefits of a proportion of these services would also be significant.

Replacing the Scheme's direct and indirect output with alternative renewable sources would impose additional costs on society of around $170 to $220 million per year (around $2.0 to $2.6 billion in present value terms).[2] Furthermore, it would take time to construct the alternatives, creating a need for increased thermal generation in the meantime. The annual costs for that

[11] As discussed later, we categorise the output of the Tekapo A and B hydro stations as direct generation of the Tekapo Power Scheme. In addition, by virtue of the fact that water flowing through these two stations enters Lake Pukaki, there is an increase in water available for generating power in the Ohau A, B and C hydro stations (owned by Meridian Energy) which would otherwise not arise. We refer to additional generation in the Ohau stations as indirect output from the Tekapo Power Scheme.

[2] All present values are calculated over a 35 year term (the maximum length of a consent under the Resource Management Act) and using an 8% discount rate (as recommended by the Treasury for commercial proposals – see www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/reporting-financial/discount-rates). We note that this discount rate is relatively high – prior to October 2024 the recommended discount rate for

generation would be approximately $250 to $370 million per year. The increased thermal generation would also significantly raise New Zealand's greenhouse gas emissions, by the equivalent of 450,000 to 1.13 million cars per year while it was operating.

The Scheme also provides significant national benefits through its ability to vary the energy output to match system conditions (both directly at the Tekapo A and B stations, and indirectly by making more water available for the Ohau stations to vary their output). This helps to maintain reliable electricity supply to consumers. The cost estimates above are expected to be conservative because they do not account for the economic premium we expect the Tekapo Power Scheme to earn going forward as the need for renewable controllable generation increases with decarbonisation of the economy.

In addition to its contribution to national electricity supply, the Tekapo Power Scheme (specifically the Tekapo A station) provides significant regional benefits by providing power to consumers in the Tekapo Albury region when that area is periodically cut-off from the rest of the grid. Without the Tekapo A station, an alternative electricity source would need to be developed as a local back-up. This would be expected to cost around $17 million in present value terms, otherwise consumers in the local area would likely experience power cuts for 200 to 250 hours per year.

Finally, the Scheme provides a significant national benefit to New Zealand electricity consumers by avoiding electricity price increases that would occur if the Scheme needed to be replaced. Replacing the Scheme's direct and indirect generation would result in more expensive generation (mostly thermal generation and demand response) being required in the short term, equating to price increases of around $60/MWh. In the long term, the development of more expensive renewables would be required (due to an upward-sloping cost-supply curve), equating to price increases of around $7.5/MWh. Using our central projection of total consumer demand, this equates to a present value increase in costs to consumers of approximately $9.2 billion.

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energy projects was 5%, and the Treasury also recommends a lower discount rate of 2% for non-commercial proposals. Using the previously recommended 5% discount rate would, when valuing a constant stream of benefits, increase these present values by roughly 40% over 35 years.

1 Introduction

1.1 Purpose

Genesis Energy Ltd (Genesis) is seeking to obtain the environmental consents needed to allow operation of the Tekapo Power Scheme (the Scheme) after 2025 when existing consents expire.

This report describes the Tekapo Power Scheme from an electricity sector perspective, and in particular the electricity system benefits the scheme is expected to provide if it continues to operate into the future.

1.2 Overview of Tekapo Power Scheme

In summary, the Tekapo Power Scheme comprises two hydro-electric power stations, referred to as "Tekapo A" (capacity 30 MW) and "Tekapo B" (capacity 160 MW). Water for electricity generation is stored in Lake Tekapo by virtue of control gates where the lake discharges into the Tekapo River. Water is diverted through Tekapo A into the Tekapo Canal, then through Tekapo B before discharging into Lake Pukaki.

In addition, the Tekapo River is dammed approximately two kilometres downstream of the control gates by a concrete weir, creating Lake George Scott. Water spilled from Lake Tekapo and impounded in Lake George Scott can be discharged into the Tekapo Canal. Water from Lake Tekapo can also flow over Lake George Scott Weir and continue down the Tekapo River to Lake Benmore.

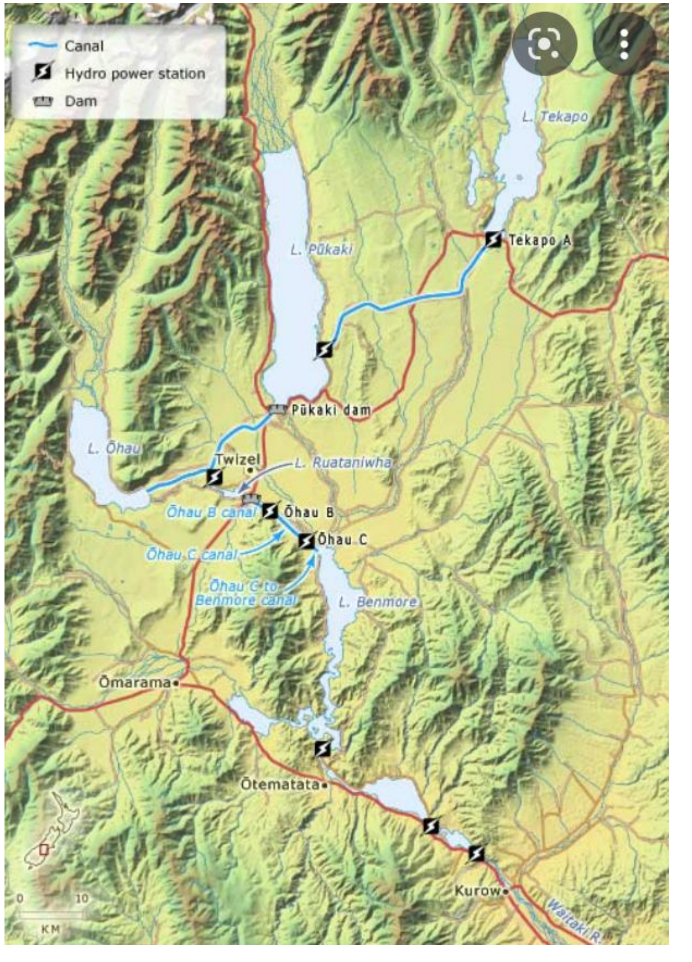
1.2.1 Direct generation output from Tekapo Power Scheme

The normal operating mode for the Tekapo Power Scheme is for water to be released from Lake Tekapo and then flow through both the Tekapo A and Tekapo B power stations before entering Lake Pukaki. This mode of operation maximises the electrical energy that can be *directly* obtained from water flows in the Tekapo A and B stations.

1.2.2 Indirect generation output from Tekapo Power Scheme

However, when considering the impact of the Tekapo Power Scheme on the electricity system, it is critical to recognise that it has significant indirect effects beyond the power generated by the Tekapo A and Tekapo B stations.

Figure 1: Map of the Tekapo Power Scheme and Ohau power stations



Source: Te Ara: The Encyclopedia of New Zealand, Waitaki power stations. https://teara.govt.nz/en/interactive/22468/waitaki-power-stations.

The indirect effects arise because water flowing into Lake Pukaki from Lake Tekapo becomes available for generation at the Ohau A, B and C stations (operated by Meridian Energy) as shown in Figure 1. Water released from Lake Tekapo that flows down the Tekapo River does not become available for generation at the Ohau stations.[3]

Direct and indirect generation output from Tekapo Power Scheme

In this report we use the term "Tekapo Power Scheme" to refer to the Tekapo A and B power stations *and* the Ohau A, B and C stations.

We refer to the electrical output of the Tekapo A and B power stations as **direct generation** from the Tekapo Power Scheme.

We refer to the additional electrical output at the Ohau stations arising from the Tekapo Power Scheme as **indirect generation**.

Information from the Electricity Authority (the generation sector regulator) shows that on average, for every 100 units of energy generated directly by the Tekapo A and Tekapo B stations, there is an associated additional 88 units of energy generated in the Ohau A, B and C stations.

Put another way, when viewed as a combined whole, 53% of the energy output from the Tekapo Power Scheme is generated in the Tekapo A and B stations, and 47% in the Ohau A, B and C stations.

It is very important to consider both the direct and indirect generation when considering the significance of the Tekapo Power Scheme from an electricity system perspective.

1.3 Information sources

Concept has primarily drawn on public information sources in preparing this report. In most cases, these sources are identified by footnotes or specific references. Where information is not referenced to external sources, it is generally based on estimates or data that have been developed directly by Concept.

In some areas, Concept has relied upon information sourced from Genesis. These are:

- Information on the frequency and duration of 'islanding' events when Tekapo A station provides the sole source of supply to customers in the Albury Tekapo area
- Price and generation information at the Tekapo A and B stations used to cross-check other price and generation data

1.4 Structure of report

This report is structured as follows:

- Chapter 2 provides an overview of the electricity sector and the wholesale electricity market
- Chapter 3 describes historical and projected demand for electricity, and the past and projected trends in generation
- Chapter 4 describes the benefits that the Tekapo Power Scheme provides to the electricity system.

[3] The Benmore, Aviemore,and Waitaki power stations also lie further downstream from the Ohau stations. However, the Tekapo Power Scheme does not directly increase the output from these stations because water reaches them irrespective of whether it flows via the Tekapo A and B stations or the Tekapo River.

2 Electricity sector overview

2.1 Summary – electricity sector overview

Regulation of the electricity generation sector is designed to encourage competition. At its centre there is a regulated auction-based spot market, in which generators make supply offers every 30 minutes. The generators with the lowest offer prices are selected to satisfy demand in each half hour.

Spot prices vary depending on the relative balance of electricity supply and demand at different times of the day and year. Prices also vary by location on the grid, reflecting the local supply/demand balance and the extent of network constraints and power losses which occur when electricity is transported on the grid.

The spot prices generated in the electricity market provide important information about the value of different types of generation, such as whether it has controllable output or not, and where it is located on the grid.

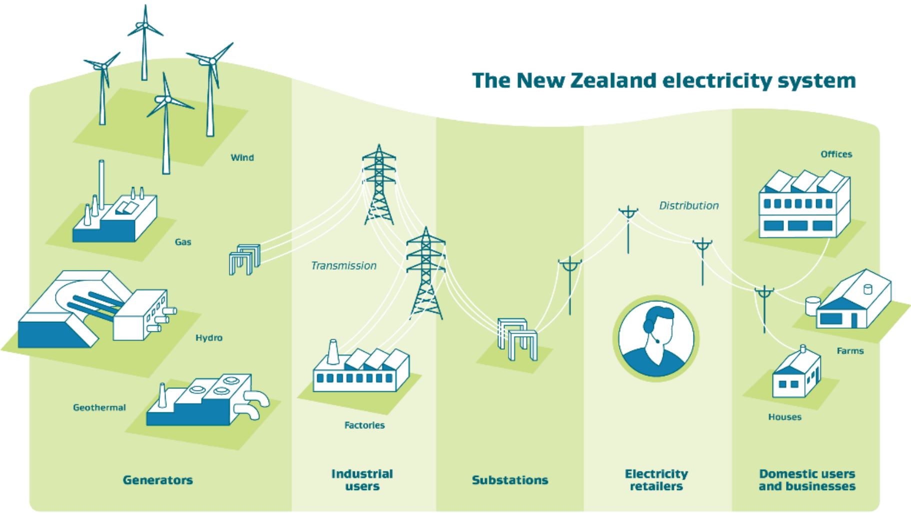
2.2 Electricity industry structure

The electricity supply chain can be divided into four main segments: generation; transmission, distribution, and retail sales. This is shown diagrammatically in Figure 2. The Tekapo Power Scheme is part of the generation segment of the industry.

Competition is possible in the generation and retailing segments and regulation of these sectors has been focussed on facilitating competition.

The transmission and distribution segments are not subject to competition because it is generally uneconomic to replicate electricity networks. These businesses are regulated under Part 4 of the Commerce Act. This provides for price control of their services, except where there is strong alignment of supplier and consumer interest via community ownership of a network.

Figure 2: Overview of electricity industry structure



Source: MBIE, Electricity industry. https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/electricity-market/electricity-industry/.

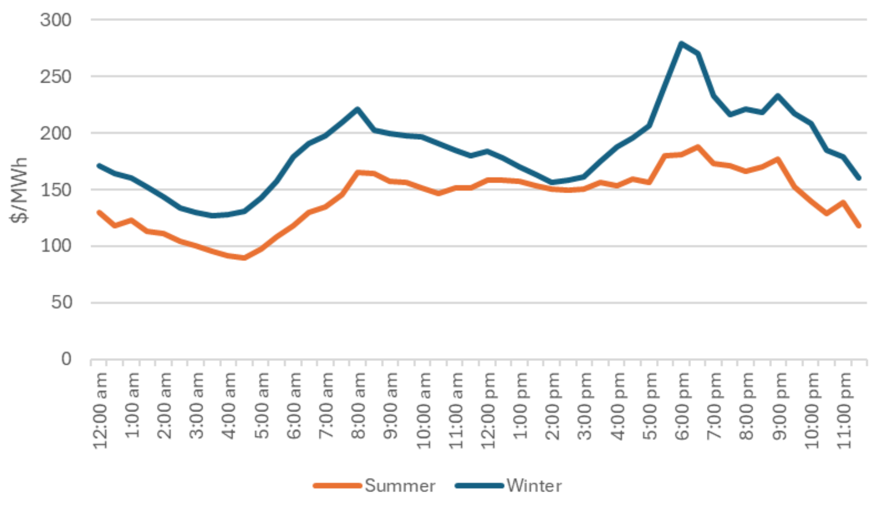
2.3 Wholesale electricity market

The platform that underpins generation sector competition is the electricity spot market. All generators connected to the grid are required to participate in a half-hourly auction process. The cheapest combination of offers that will securely meet demand is used to determine which generation will be selected to run in each half hour.

Supply and demand conditions can vary substantially within a day and across the year. The cost of generating power in peak demand periods is typically much higher than other periods. This leads to predictable variations in spot prices across the year, as shown by Figure 3.

Spot prices will also fluctuate due to unexpected events, such as the early arrival of a cold front which lifts power demand for electric heating, or tighter supply such as a prolonged calm period which reduces wind generation.

Figure 3: Average daily price profile by season (2021)[4]



Source: Concept analysis of Electricity Authority data. https://www.emi.ea.govt.nz/.

2.3.1 Premium for flexible supply

Because spot prices are higher when the supply/demand balance is tight and vice versa, generators[5] that can control their output are able to earn a premium over those that operate at a constant rate or cannot control their output. The presence of this premium is important to maintain reliable supply, because it encourages generators to be available when there is the greatest need for additional supply.

2.3.2 Locational signals

Another feature of the spot market is that prices are determined at many locations across the grid. Prices at each location reflect the local balance of supply and demand, including the effect of physical transmission losses if power needs to be carried over long distances from generation to points of usage.

Price differences also occur if parts of the grid reach their maximum physical operating limits. When such limits arise, spot prices will typically rise downstream of a transmission constraint to indicate to generators or retailers/purchasers located there that they should increase production or reduce consumption respectively to relieve the effects of the constraint.

In some cases, there may be no transmission possible between regions. When this occurs, the isolated region is said to be “islanded” from the rest of New Zealand. Demand in the region must be met entirely from local sources, and spot prices again provide important signals to maintain reliable supply inside the islanded region.

2.4 Contract market

Most electricity customers do not want to deal with the complexity of half hourly price variations in the spot market. Nor do most generators wish to be wholly reliant on the spot market with prices that are uncertain and constantly varying.

Instead, the great majority of electricity generation and consumption volumes are sold on contracts which smooth out short term price volatility. These can be retail supply contracts where generator-retailers organise the transmission and distribution services for the customer as well as supplying wholesale energy, or bilateral ‘hedge’ contracts which smooth spot price volatility, with the customer retaining responsibility for organising transmission and distribution services.

While contracts can provide generators and consumers with insulation from short-term variation in spot prices, this only lasts for the contract duration

[4] We have used 2021 data as more recent years have been particularly ‘wet’ or ‘dry’, resulting in less standard prices.

[5] Or other types of resources that can improve the supply/demand balance, such as batteries or electricity consumers who can reduce their usage – known as demand response providers.

(typically 1-3 years). More generally, when contracts are being negotiated, the price will be affected by the parties' expectations about future spot prices. This is because buyers and sellers each have the alternative of not contracting and relying instead on the spot market. Hence their expectation of future spot prices will affect their willingness to contract at different prices.

2.5 Climate change related policies

While this chapter focusses largely on the electricity sector, it is also important to briefly describe policy relating to greenhouse gas emissions.

New Zealand law sets a target for the country to reduce net emissions of greenhouse gases (except biogenic methane) to zero by 2050. The law also establishes the Climate Change Commission, which has the role of providing independent expert advice and monitoring to help keep successive governments on track to meet the legislated long-term goals.[6]

A key instrument for achieving the net emission target is the Emissions Trading Scheme (ETS). In essence, this scheme requires greenhouse gas emitters to purchase emission units issued by the New Zealand government to offset their domestic greenhouse gas emissions.[7] The volume of units available for purchase is set by the government. Emission units can also be generated by carbon removal activities, such as the permanent planting of forests to act as carbon sinks.

The market clearing price for emission units in New Zealand is discovered by trading among parties, such as those who need to buy units to acquit their emission liabilities and/or those who generate units. The price of an emission unit has increased over the last five years, but the price has been fairly volatile as shown in Figure 4.

Figure 4: New Zealand carbon price

Source: github.com/theecanmole/nzu/blob/master/spotprices.csv.

[6] Climate Change Response Act 2002, section 5B.

[7] Strictly speaking, the obligation to purchase and surrender units may fall on a party other than the final emitter (e.g. gas producers rather than consumers). Nonetheless, in such cases, final emitters are likely to bear the cost of acquiring the emission units when they purchase gas from producers.

3 Electricity demand and supply

3.1 Summary – electricity demand and supply

Electricity is vital in our daily lives. Many of the social and economic benefits we enjoy stem directly from technologies relying on electricity. Looking ahead, electricity is expected to become even more important as New Zealand moves to decarbonise the economy using renewable generation sources.

To meet its decarbonisation objectives, New Zealand will in future need to develop new generation sources at an unprecedented rate. Much of that generation will be from wind and solar power. Although these are very cost competitive, their output is subject to fluctuations due to weather, etc.

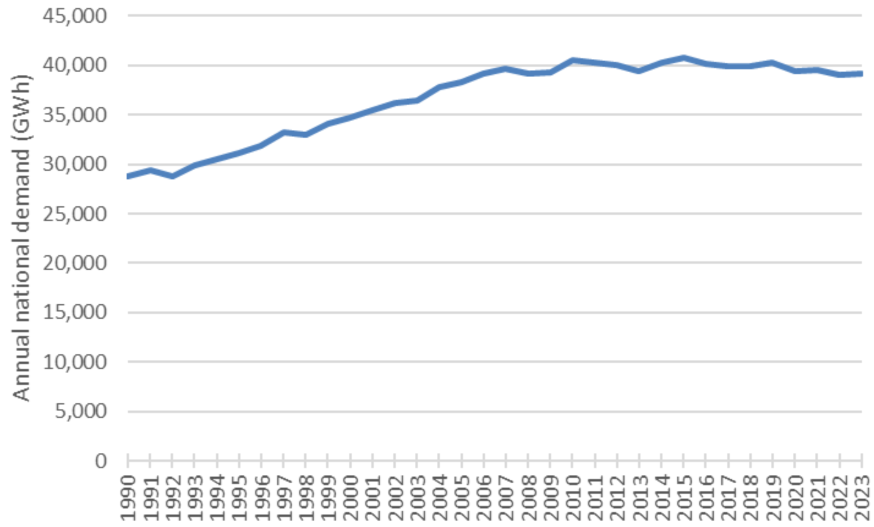
While batteries are expected to help in smoothing out much of the very short-term fluctuation in supply from these sources, they are not suitable for addressing variations which occur from week to week or longer. Other sources of flexibility will be needed. One of the most important is expected to be hydro generation that has access to stored water. This type of generation has the twin benefits of being renewable and controllable – both of which will be increasingly important as New Zealand decarbonises its economy.

3.2 Electricity demand trend - historical

Electricity is used in almost every part of our society and economy. We need it for heating, lighting, entertainment and communications. Often there are simply no alternatives.

As shown in Figure 5, annual electricity demand has been fairly stable at around 40,000 GWh per year over the last 15 years, and was preceded by a period of steady growth between 1990 and 2005.

Figure 5: Historical electricity demand (1990-2023)



Source: Concept analysis of MBIE data. https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/electricity.xlsx.

3.3 Electricity demand trend - projected

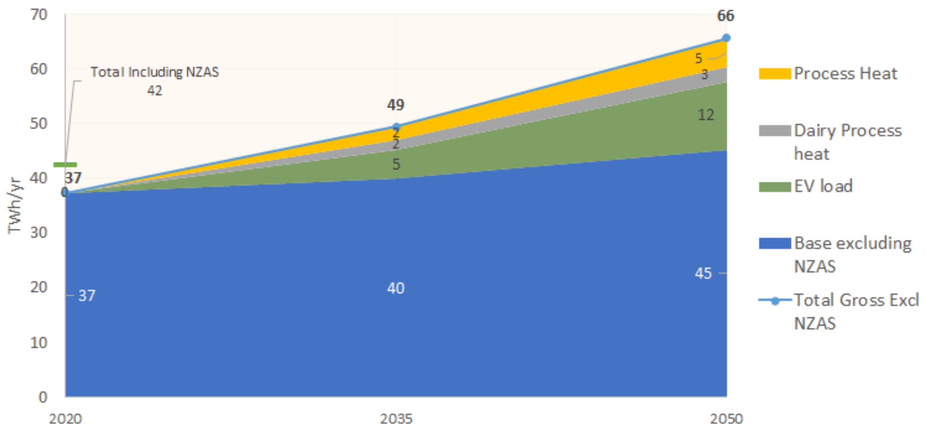
Electricity demand is expected to grow very substantially as New Zealand uses more electricity to decarbonise the economy. For example, electricity is expected to largely displace petrol and diesel as an increasing number of electric vehicles take to the country's roads. Likewise, electricity is expected to replace coal and gas for industrial process heat in many applications.

Figure 6 shows a projection of future electricity demand published in early 2022.[8] Clearly, the very long horizon of the projection (to 2050) means that it has some inherent uncertainty. Having said that, projections from other sources such as MBIE, Transpower and the Climate Change Commission show

[8] This projection was prepared by an industry advisory group appointed by the Electricity Authority and was published in an issues paper which can be found at Price discovery under 100% renewable electricity supply | ea.govt.nz.

a broadly similar picture.[9] In particular, while there are some differences in pace and scale of electrification, they all predict significant increases in demand over time due to electrification of the economy.

Figure 6: Projected future electricity demand projection



Source: Electricity Authority (Market Development Advisory Group), 100% renewable electricity supply – simulation assumptions and results. https://www.ea.govt.nz/documents/1097/06-100-Renewable-Electricity-Supply_-Simulation-Assumptions-and-Results.pdf.

Key points to note from the projection are:

- Demand (excluding for the Tiwai aluminium smelter) is expected to grow by around 32% by 2035, and a further 35% by 2050.
- Most of the increase is expected to come from electric vehicles (EVs) and the increasing use of electricity for process heat in industry, especially food processing.
- Base demand is projected to be relatively stable – this is because population and economic growth are expected to be largely offset by rising efficiency of energy use (for example through greater insulation of homes).

3.4 Supply and demand must be balanced at all times

Electricity is unusual because supply and demand need to be kept in a tight balance at all times. If this is not achieved, it can lead to widespread blackouts. In particular, if insufficient electricity is supplied to meet demand, the electrical frequency will begin to drop below the normal level of 50 Hertz (and vice versa). Power plants are designed to operate within a fairly narrow frequency range and if the grid frequency moves outside this range for too long, the power plant will automatically disconnect from the grid (called a 'trip') to protect itself from damage.

Ultimately, if too many power plants disconnect due to a frequency disturbance there will be 'sympathetic tripping' by other plant and cascade failure. This can lead to widespread blackouts affecting many customers. For example, over 850,000 customers lost power in Australia in 2016 due to an event of this type. Restoring power after such events can take some time as supply and demand need to be brought back in a way that maintains balance throughout.[10] In the Australian event some customers were restored within a few hours while others took days.

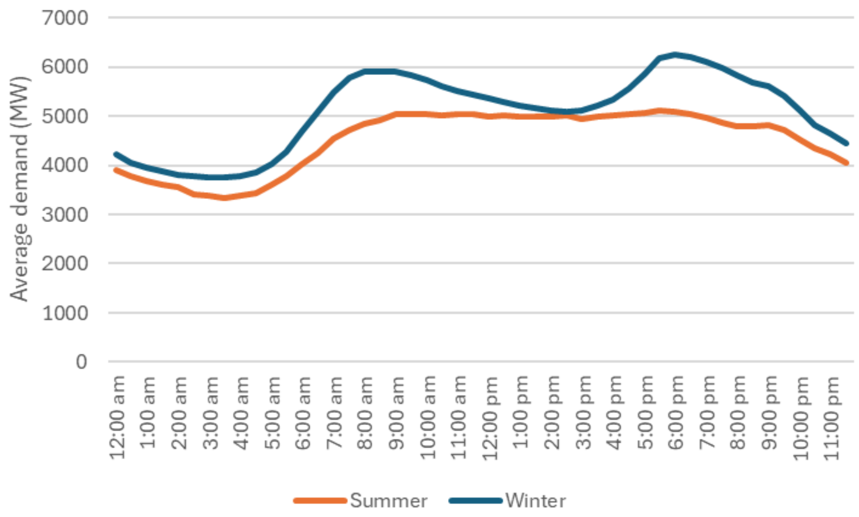
3.5 Varying power demand creates a need for flexible supply

Demand for electricity is not constant through the day or across seasons. Figure 7 shows grid power demand for a typical summer and winter day. The chart shows how demand varies between a minimum level of around 3,300 MW and a peak of 6,200 MW – a variation of almost 90% between trough and

[9] See Electricity Demand and Generation Scenarios: Results summary July 2024, Whakamana i te Mauri Hiko data report figures | Transpower.co.nz and Electricity market modelling datasets 2021 final advice | Climatecommission.govt.nz.
[10] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

peak. Another point to note is the steep increase in demand on winter mornings, with a rise of almost 50% between 5am and 9am.

Figure 7: Average electricity demand for summer and winter days in 2024



Source: Concept analysis of Electricity Authority data. https://www.emi.ea.govt.nz/.

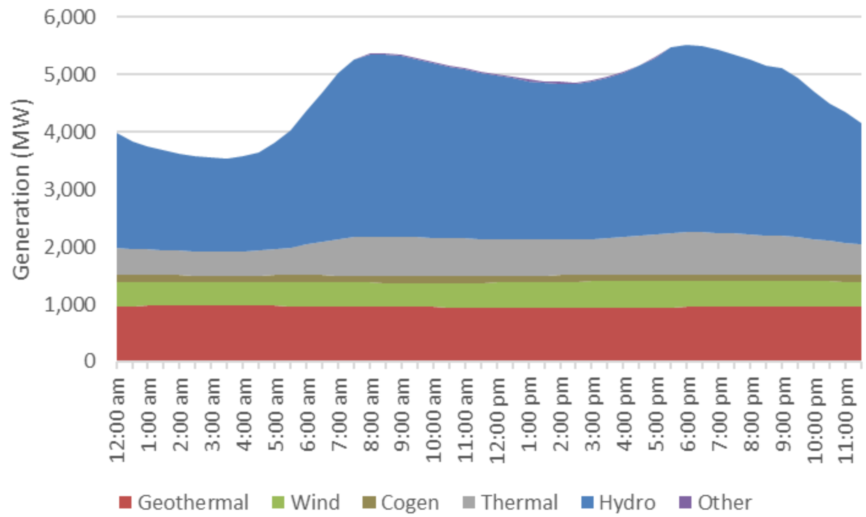
These sorts of change in demand mean that the electricity system needs flexible supply sources that can be ramped up or down quickly to ensure that the grid remains balanced.

3.6 Uncontrollable generation increases need for other flexible supply

Some forms of generation cannot be readily controlled – often being referred to as 'intermittent'. Examples are wind and solar generation, whose power output will vary with prevailing weather and solar conditions. Another intermittent source is 'run-of-river' hydro generation. These are hydro power stations that have little or no access to storage lakes, and hence generate according to natural flows in the river.

By contrast, hydro stations with sizeable storage reservoirs are an important source of flexible supply. In particular, these stations provide much of the short-term flexibility needed to counteract hourly, daily and seasonal variations in demand and intermittent supply. This is illustrated by Figure 8 which shows the variation in hydro generation across a typical winter day.

Figure 8: Average generation by generation type in 2024



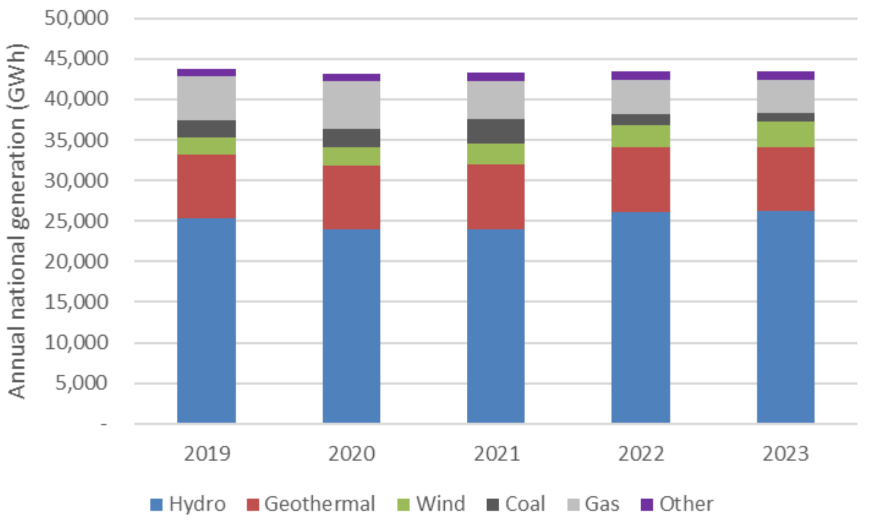
Source: Concept analysis of Electricity Authority data. https://www.emi.ea.govt.nz/.

However, even hydro stations with storage are exposed to supply fluctuations. This is because they are dependent on rainfall and/or snow melt to fill their storage lakes. Accordingly, after prolonged dry periods storage lakes will be lower, limiting the amount of power that the associated hydro stations can generate.

3.7 Electricity supply trend - historical

Electricity has been supplied by a range of generation types as shown in Figure 9. During the five years from 2019-2023[11] hydro was responsible for around 58% of electricity generation in New Zealand. The other significant generation types are geothermal (18%), gas (11%), wind (6%) and coal (4%).

Figure 9: Historical electricity generation



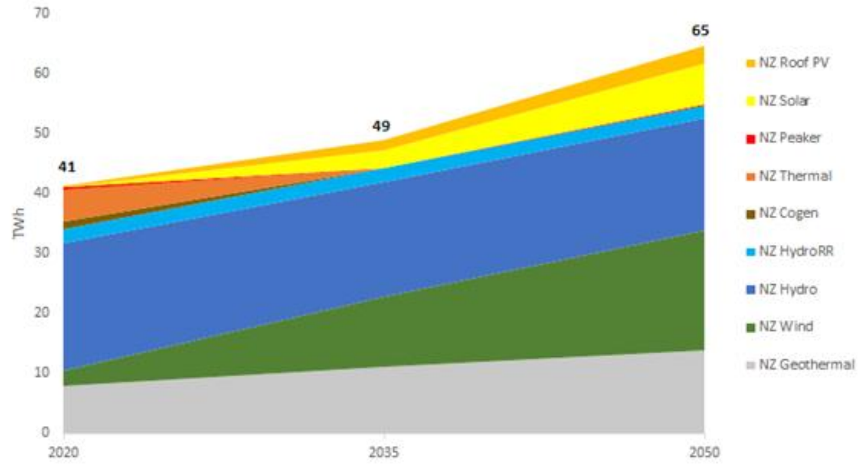
Source: Concept analysis of MBIE data. https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/electricity.xlsx.

3.8 Electricity supply trend - projected

Looking to the future, very large increases in renewable generation will be required to meet New Zealand's decarbonisation goals. Some of the generation will be needed to replace existing thermal generation and directly reduce electricity sector emissions, but an even greater volume will be needed for electric vehicles and electricity for process heat to decarbonise other parts of the economy.

Figure 10 shows a recent projection of the potential sources of future supply generation. As with projected demand, given the long horizon there is some inherent uncertainty about the precise mix of sources. Nonetheless, the projection is mainstream and other sources paint a similar picture for new supply.

Figure 10: Projected future electricity supply



Source: 100% renewable electricity supply – simulation assumptions and results, Electricity Authority, Market Development Advisory Group. https://www.ea.govt.nz/documents/1097/06-100-Renewable-Electricity-Supply_-Simulation-Assumptions-and-Results.pdf.

Key points to note from the projection are:

- Geothermal power is expected to grow over time – reflecting its position as a proven technology with competitive costs. However, its growth is limited by the availability of sites with access to the underlying energy source.

[11] While data was not available for 2024 at the time of writing, 2024 involved low rainfall in winter together with gas shortages, and as such we expect this would bring average hydro and gas generation down and average coal generation up.

- A much larger contribution to new supply is expected to come from wind and solar generation. These have become much more competitive over time with improving technology, and further gains are expected.
- In aggregate, the proportion of electricity generated from intermittent sources (solar and wind) is expected to increase from 7% in 2020 to around 46% by 2050. As discussed in section 4.5, this change has significant implications for the role of flexible hydro generation.

Achieving New Zealand's decarbonisation goals will require the development of generation at a pace that is unprecedented. As shown in the previous chart**Error! Reference source not found.**, it will require the development of a round 1,100 GWh of new generation capability every year until 2050. This pace of development is almost 2.5 times the rate achieved in the last 25 years.

To provide a sense of scale, it is roughly equivalent to adding a new set of Tekapo A and B stations to the electricity system *every 11 months* until 2050.

These projections assume that all existing renewable stations will retain their current generation capabilities after their current resource consents expire – i.e. that their operating capabilities will not be reduced during reconsenting processes. If that doesn't eventuate, the required future-scale up in renewable development would be even greater than this. The required generation projections are also dependent on demand growth assumptions. Of particular note, if a large scale hydrogen production industry or other so-called 'power-to-X' applications were to develop, then even more new generation will be required.

4 National and regional benefits of Tekapo Scheme

4.1 Summary – electricity sector benefits of Tekapo Scheme

The Tekapo Power Scheme generates substantial volumes of 100% renewable electricity. In energy terms, the Scheme's average annual output (both direct and indirect) is sufficient to supply approximately 228,000 Canterbury households.

In considering the economic benefits of the Scheme, we have distinguished between

- the national and regional economic benefits to New Zealand, in terms of the avoided capital, operating, and fuel costs of the stations that would otherwise need to be built and operated if the Scheme needed to be replaced
- the national benefit to New Zealand electricity consumers in terms of avoiding the electricity price increases that would occur if the Scheme needed to be replaced.

We calculate these benefits by determining the cost of replacing the full extent of services the Tekapo Power Scheme provides with the next best alternative – i.e. the cost of replacing the Tekapo Power Scheme in its entirety. If only a proportion of these services needed to be replaced, for instance due to a partial reduction in the output or flexibility of the Scheme, the costs of replacement would be lower. However, due to the large benefits the scheme provides as a whole, it is likely that the benefits of a proportion of these services would also be significant.

Replacing the Scheme's direct and indirect output with alternative renewable sources would impose additional costs on society of around $170 to $220 million per year (around $1.9 to $2.6 billion in present value terms).[12] Furthermore, it would take time to construct the alternatives, creating a need for increased thermal generation in the meantime. The annual costs for that generation would be approximately $250 to $370 million per year. The increased thermal generation would also significantly raise New Zealand's greenhouse gas emissions, by the equivalent of 450,000 to 1.13 million cars *per year* while the additional thermal generation was operating.

An important feature of the Tekapo Power Scheme is that there is significant ability to vary the energy output to match system conditions (both directly at the Tekapo A and B stations, and indirectly by making more water available for the Ohau stations to vary their output). This helps to maintain reliable electricity supply to consumers. The cost estimates above are expected to be conservative because they do not account for the economic premium that we expect the Tekapo Power Scheme to earn going forward as the need for renewable controllable generation increases with decarbonisation of the economy.

In addition to its contribution to national electricity supply, the Tekapo Power Scheme (specifically the Tekapo A station) provides power to consumers in the Tekapo Albury region when that area is periodically cut-off from the rest of the grid. Without the Tekapo A station, an alternative electricity source would need to be developed as local back-up. This would be expected to cost around $17 million in present value terms, otherwise consumers in the local area would likely experience power cuts for 200 to 250 hours per year.

Finally, the Scheme provides a significant national benefit to New Zealand electricity consumers by avoiding electricity price increases that would occur if the Scheme needed to be replaced. Replacing the Scheme's direct and indirect generation would result in more expensive generation (mostly thermal generation and demand response) being required in the short term,

[12] All present values are calculated over a 35 year term (the maximum length of a consent under the Resource Management Act) and using an 8% discount rate (as recommended by the Treasury for commercial proposals – see www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/reporting-financial/discount-rates). We note that this discount rate is relatively high – prior to October 2024 the recommended discount rate for energy projects was 5%, and the Treasury also recommends a lower discount rate of 2% for non-commercial proposals. Using the previously recommended 5% discount rate would, when valuing a constant stream of benefits, increase these present values by roughly 40% over 35 years.

equating to price increases of around $60/MWh. In the long term, the development of more expensive renewables would be required (due to an upward-sloping cost-supply curve), equating to price increases of around $7.5/MWh. Using our central projection of total consumer demand, this equates to a present value increase in costs to consumers of approximately $9.2 billion.

4.2 Tekapo Power Scheme contributions to electricity system

The Tekapo Power Scheme contributes to the electricity system in four key ways:

1. It provides renewable energy to power homes and businesses across New Zealand.
2. It is a source of controllable energy, which helps in balancing the overall electricity system.
3. It supplies local consumers in the Tekapo basin during periods when they are cut off from the rest of the national grid.
4. It lowers electricity prices for consumers.

The next sections discuss each of these contributions in more detail. Specifically:

- Sections 4.4 to 0 estimate the national and regional economic benefits of the Scheme in terms of the avoided capital, operating, and fuel costs of the stations that would otherwise need to be built and operated if the Scheme needed to be replaced.
- Section 4.7 estimates the national benefit to New Zealand electricity consumers in terms of avoiding the electricity price increases that would occur if the Scheme needed to be replaced.

4.3 Tekapo Power Scheme provides renewable energy

The Tekapo Power Scheme generates 100% renewable energy, and on average produces around 1,870 GWh of electricity each year.[13]

To put this into perspective, this is sufficient energy to supply around 228,000 average Canterbury households.[14] By way of comparison, there were 282,039 residential dwellings in the Canterbury region in 2023 according to StatsNZ.

4.4 Economic value of Tekapo Scheme renewable energy

The economic value of the Tekapo Power Scheme's energy supply can be estimated by considering the costs that would be incurred if the Scheme were not available to operate. The greater those costs, the greater the benefits from continued operation of the Scheme and vice versa.

Before discussing the estimates themselves, it is important to emphasise that we have compiled estimates of *economic* effects – i.e. the impacts on New Zealand society as a whole. The commercial effects for the owner of the Scheme will differ from the economic effects for a range of reasons. In particular, a substantial portion of Scheme's electricity-related benefits do not accrue to the owner because they arise from indirect generation. It is also important to recognise that the estimates only incorporate electricity-related effects.

Returning to the estimation of the cost of obtaining substitute energy sources, it is useful to consider two timeframes: the initial period when alternative resources already in existence must provide the substitute energy, and the longer-run when permanent substitutes could be in place (noting it generally takes years to construct new power stations).

[13] Including both direct and indirect output. This is based on average levels between 2000 and 2024, but excluding 2012-14 when output was reduced due to major remedial work on the Tekapo canal.

[14] Canterbury residential users consume more electricity on average than the national average. This comparison focuses on average energy needs for a Canterbury residence over a year and does not account for peak demand requirements on any given day. The annual average figure per residential connection in Canterbury was 8,207 kWh in 2024. See Electricity Authority - EMI (market statistics and tools).

4.4.1 Initial cost impact if supply from Tekapo Scheme not available

The electricity system normally has some unutilised plant that can operate at relatively short notice to provide so-called reserve. This reserve is largely comprised of capacity at thermal power stations. However, this type of plant has high operating costs (one of the reasons it is seldom used) and is therefore not suitable as an ongoing substitute.

If the Tekapo Power Scheme was not available, the most likely initial effect would be increased operation of thermal power stations, running on gas or coal.

Table 1: Initial annual costs to substitute for Tekapo Power Scheme supply

	Gas-fired substitute	Coal-fired substitute
Annual cost to replace lost energy ($m/yr)	252	370
Increase in emissions (tCO2e/yr)	729,147	1,813,520
Emissions equivalent (number of cars)	452,470	1,125,375

Source: Concept analysis of MBIE data from WSP report. https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf.

Table 1 sets out estimates of the costs of obtaining power from these types of generation units. The table assumes that both direct and indirect generation from the Tekapo Power Scheme are not available. The underlying fuel cost estimates are based on Concept's analysis of publicly disclosed gas contract information and forward prices for coal, and forward projections for New Zealand carbon prices.[15]

As shown in Table 1, it would be very costly to replace energy from the Tekapo Power Scheme with electricity generated from thermal power stations. Even the cheapest option (gas-fired) would incur a cost of over $250m per year. Using coal-fired generation instead would increase these costs by almost 50%.

It is important to note that the estimates in Table 1 assume that sufficient spare thermal plant is available to fully substitute for the Tekapo Power Scheme. That assumption is probably optimistic given the large volume of energy that would be lost if the Tekapo Power Scheme could not operate.

A more likely outcome is that thermal generation would be a partial substitute, and power rationing would be required in some periods (e.g. cold winter evenings) due to insufficient spare thermal capacity. In that case, the costs would be even higher than those shown in Table 1.

The table also shows the expected emissions impact of replacing the renewable energy from the Tekapo Power Scheme with output from thermal power stations. If gas-fired units were used as the source (a best case for thermal energy), emissions would rise by over 700,000 tonnes of carbon dioxide equivalent per year. If coal-fired units were used as the source, there would be an increase of over 1.8 million tonnes per year. To put these figures into perspective, that would be roughly equivalent to the annual emissions from an additional 450,000 or 1.13 million vehicles respectively.[16] In this way, the Tekapo Hydro Scheme also supports climate change mitigation by helping New Zealand produce less greenhouse gas emissions than would be the case if the Scheme was not available.

4.4.2 Ongoing cost impact if supply from Tekapo Power Scheme not available

If supply from the Tekapo Power Scheme was not available on an ongoing basis, new generation sources would need to be developed as a replacement. The most likely alternatives are geothermal, solar or wind generation, or some mix of these. On a dollar per unit of energy basis, they would have lower economic costs than the thermal plant options discussed above. However,

[15] See https://www.commtrade.co.nz/

[16] These estimates are based on the average emission/km travelled of new vehicles, and assuming they each travel 10,500 km per year (the New Zealand average for 2020).

they would all involve significant upfront capital expenditure and take some time to build.

Table 2 shows the estimated ongoing costs to produce substitute energy if the Tekapo Power Scheme was not available. The estimates incorporate the additional expenditure that would be required on alternative new power stations, less an allowance for avoided expenditure on the Tekapo Power Scheme assets.[17]

Table 2: Ongoing costs to substitute for Tekapo Power Scheme supply

	Lower estimate	Higher estimate
Annual cost ($m)	168	222
Total cost over 35 years ($m)	1,953	2,590

Source: Concept estimates.

Given the uncertainties in some variables, we have calculated lower and higher cost estimates for obtaining substitute energy. The overall cost impacts range from $168 to $222 million per year. These estimates are lower than the costs associated with replacing Tekapo Power Scheme output with thermal generation but are still very substantial in annual terms.

They are even more significant when viewed over the likely lifetime of substitute energy sources such as solar or wind farms. In present value terms, the costs would be approximately $1.9 to $2.6 billion.

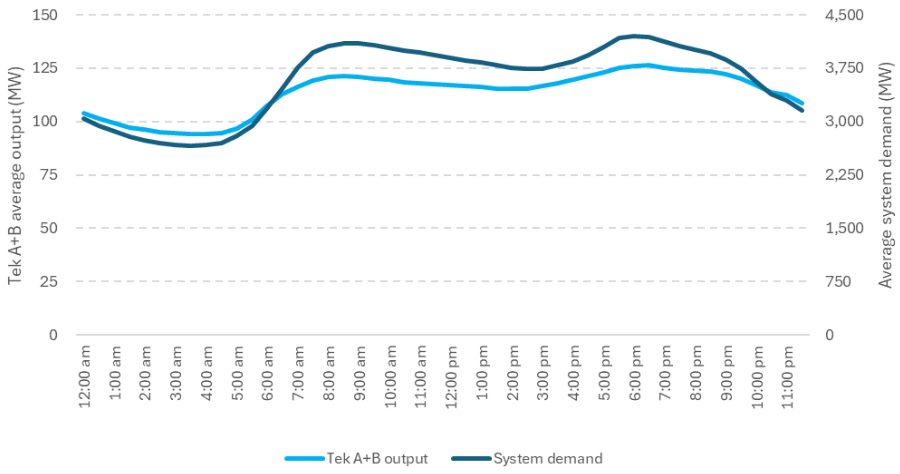
4.5 Tekapo Power Scheme provides controllable energy

An important feature of the Tekapo A and B stations is that they have been designed so their level of generation can be raised or lowered (within limits) to reflect the needs of the electricity system. In part, this flexibility arises because the stations are close to a large hydro storage reservoir. In essence, by altering the rate at which water is released from Lake Tekapo, the output of the two stations can be varied (subject to various technical and other constraints).[18]

Some hydro generation does not have this type of flexibility because there is no upstream storage reservoir which can be readily controlled. Hence, this type of generation is known as 'run of river' hydro.

The flexibility of the Tekapo A and B stations is apparent when comparing their average output by time of day since 2000. This is shown by the light blue line in Figure 11. Also shown is the average level of electricity demand by time of day for the entire country.

Figure 11: Tekapo A and B – average output by time of day



Source: Concept analysis of Electricity Authority data for 2000-2024 (excluding 2012-14). https://www.emi.ea.govt.nz/.https://www.emi.ea.govt.nz/

The chart shows how national demand dips in the early hours of morning, before rising steeply from around 6am as New Zealanders get ready to go to

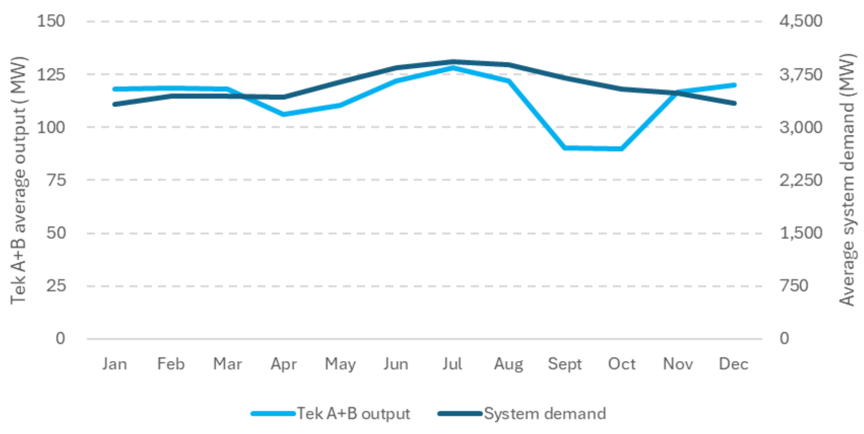
[17] This allowance is $18 million per year, and roughly reflects the average reported capital expenditure for the Tekapo Power Scheme since 2012.
[18] The Ohau A, B, and C stations can also vary their output in response to system conditions, so the additional output they can generate as a result of the Tekapo Power Scheme results is also controllable (to a degree).

work or school, etc. Demand dips slightly around midday before rising again to the evening peak.

The average output of the Tekapo stations follows the same broad pattern. This ability to vary the output from the Tekapo A and B stations is very important for the electricity system. It means the Tekapo stations can contribute higher supply when the system needs it more (i.e. when national demand is higher each day), and vice versa.

The Tekapo Power Scheme also has some flexibility to alter its level of generation across each year. This is illustrated by Figure 12 which shows average monthly generation and system demand. It shows that the Tekapo A and B stations' output and national demand both peak in the winter months, and both fall in the spring months. However, the movements in Tekapo output and national demand do not mirror each other so closely across the rest of the year.

Figure 12: Tekapo A and B – average output by time of year



Source: Concept analysis of Electricity Authority data for 2000-2024 (excluding 2012-14). https://www.emi.ea.govt.nz/.https://www.emi.ea.govt.nz/

There are two key reasons for this. Firstly, hydro inflows are generally highest in the spring/summer months due to snowmelt and rainfall patterns, whereas national demand is generally lower in summer. While the hydro storage capability of Lake Tekapo allows some of the spring/summer inflows to be 'saved' for use in winter, the lake has finite capacity. Accordingly, some of the inflows need to be utilised for generation in summer even though it is generally not the season with highest demand.

Second, while Lake Tekapo provides a significant storage buffer to catch inflows, there is uncertainty about the timing and level of inflows, with potential for unexpected droughts or floods to occur. This uncertainty means there is less flexibility to precisely control hydro generation levels across a year than across a day.

We also note that the Tekapo Power Scheme does not provide flexibility from one year to the next. Because New Zealand is a hydro-dominated system, in 'dry years' where hydro inflows are generally lower, resources that can generate more electricity at these times are particularly valuable. However, because the output of the Tekapo Power Scheme also depends on these hydrological conditions, it will generate *less* during these years.

As a result, the net effect of the Tekapo power scheme on system flexibility has been roughly neutral. The short- and medium-term flexibility (within-day and within-year) it provides is effectively offset by it being a net user of long-term (i.e. intra-year) flexibility.

A statistic which summarises the combined effect of multiple flexibility dimensions is the so-called 'capture rate'. This is defined as the average spot price earned by a specific generator divided by the average price received by a notional generator that has constant output every hour. This constant output generator can be thought of as providing 'vanilla' electricity into the system.[19]

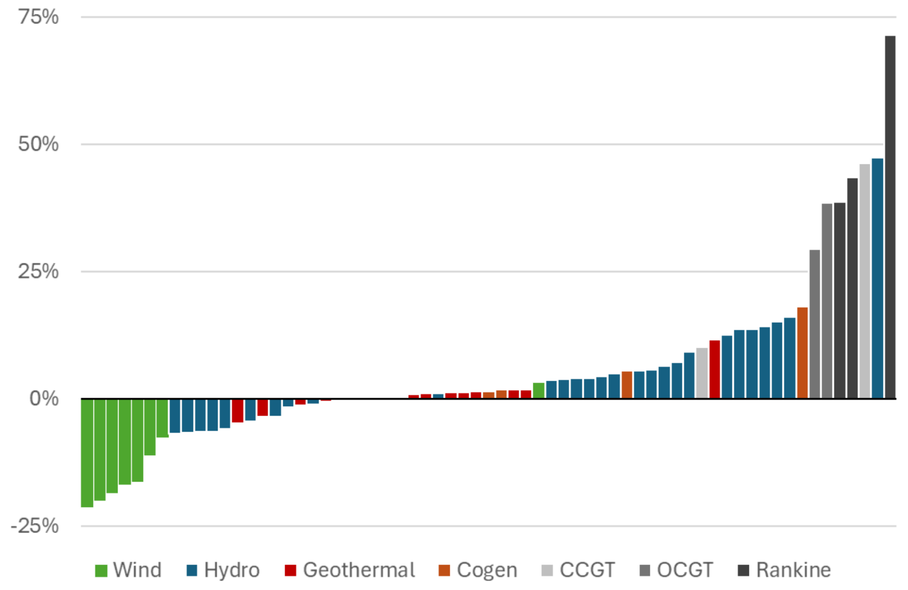
Generators that achieve a capture rate above 100% are (on average) providing supply when it is more beneficial to the system. The premium above 100% indicates their output is more valuable than the standard vanilla product.

In contrast, generators with a capture rate below 100% are (on average) contributing supply at times when it has lower benefits to the system – are therefore net contributors to the *need* for flexibility.[20] Put another way, their output is less valuable that the standard vanilla product.

The historical average capture rate for the Tekapo A and B stations has been close to 100%, indicating that overall, it has been neither a net provider nor a net user of flexibility.

Figure 13 shows indicative capture rates for all major generators in New Zealand by generation type, with the rates expressed as a premium or discount to 100% (i.e. the rate applicable for the 'vanilla' generator).

Figure 13: Indicative flexibility premium/(discount) earned in spot market



Source: Concept analysis of Electricity Authority data. https://www.emi.ea.govt.nz/.

Key observations from the chart are:

- some hydro stations have earned a premium to the vanilla energy value, while others have received a discount. This likely depends on the amount of storage they have available, and the degree to which their inflows (and therefore generation potential) is correlated to other hydro inflows across the country.
- some other stations have earned greater premia – especially the CCGT, OCGT, and Rankine units.[21] However, all of these generation types currently operate on fossil-fuels, and fossil-fuel use is likely to phase down as the electricity sector decarbonises.

[19] The term used commonly in the industry is 'baseload' energy – referring to a demand or supply source which is constant every half hour.
[20] Investment in such generators may still be economically attractive, provided their costs are low enough to offset the reduced system benefits they provide.
[21] Combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) run on gas or diesel, and Rankine units operate on gas or coal.

- wind generators have generally received a discount to the vanilla price. This indicates the stations were net users of system flexibility due to their intermittent output.

4.5.1 Cost impact if controllable energy from Tekapo Power Scheme not available

The cost estimates for substitute energy discussed in section 4.4 assumed that the Tekapo Power Scheme produces vanilla energy. As discussed above, this has generally been the case historically. However, we expect that over time, the Tekapo A and B power stations[22] will earn a premium over the vanilla price, due to two key factors:

- generation from fossil-fuelled thermal stations is currently the most flexible source of supply – which is why it commands the highest premia in Figure 13. As the electricity system decarbonises, this source of flexibility is expected to diminish and become more expensive to operate.
- generation from wind and solar currently accounts for around 7%[23] of total supply. These intermittent forms of generation require flexible energy sources to firm up their output. As they grow on the system, this will increase the value of shorter-term flexibility that can be provided from controllable sources, such as hydro generation with access to storage.

Based on our detailed modelling of the evolution of New Zealand's electricity system over the coming decades, we expect this premium earned by the Tekapo scheme will, on average over the next 35 years, be approximately 5%.[24]

This premium indicates that there would be additional costs to replace the flexibility aspects of the Tekapo Power Scheme's generation. We estimate this would be around 5% of the vanilla costs set out in Table 2, i.e. roughly $10 million per year, or around $114 million in present value terms.

4.6 Tekapo Power Scheme provides significant regional benefits at times

As noted in section 2.3.2, a region can sometimes be cut-off in electrical terms from the rest of the country. When this occurs, the isolated region is said to be "islanded" from the rest of New Zealand. This situation is relatively rare and only occurs if transmission circuits which normally link regions are out of service for maintenance or an unexpected fault.

When islanding occurs, the demand in the affected region must be met entirely from local sources. These sources must not only be large enough to satisfy local demand, but they must be controlled to ensure that local supply is perfected matched to local demand at every moment in time (called 'frequency keeping').

One of the regions in New Zealand most affected by islanding is the Tekapo-Albury area.[25] The transmission line serving this region is a single 110kV circuit running between a Transpower switchyard near Timaru and the Tekapo A power station. When this circuit is out of service, the Tekapo A power station is the sole source of electricity supply for consumers in the Tekapo – Albury area.

Figure 14 shows the extent to which local supply has been required in islanding event in the five years to March 2022. There were 27 such events, or around five per year on average. Some events only lasted for an hour or so.

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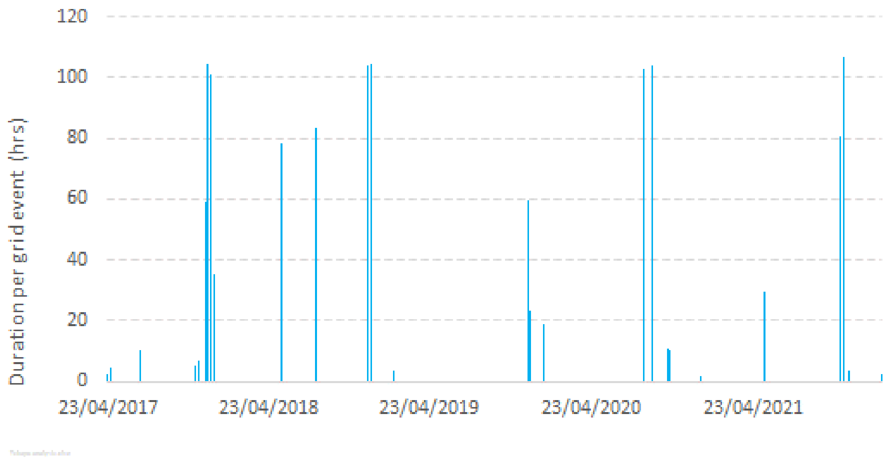
[22] As well as the Ohau A, B and C stations.
[23] See section 3.7.
[24] *"NZ electricity price forecasts"*, 15 January 2025, Concept Consulting Ltd. Report available for purchase on request.
[25] For example, the Electricity Authority estimated an average of 200 hours per year. See table 6 of www.ea.govt.nz/assets/dms-assets/26/26404High-Standard-of-Trading-conduct-MDAG-discussion-paper-on-pivotal.pdf downloaded 19 April 2022.

However, most lasted for more than 24 hrs and around a quarter lasted for four or more days.

Figure 14: Timing and duration of islanded supply from Tekapo A station



Source: Concept analysis of data provided by Genesis.

We have reviewed Transpower's planning documents to ascertain whether the single 110kV circuit is likely to be upgraded, as this could reduce or eliminate the likelihood of 'islanding' events in the Albury Tekapo area in future. Transpower's latest plan[26] indicates that no upgrades are contemplated in the forecast horizon to 2038.

Looking ahead, if the Tekapo A power station could not provide local supply when grid maintenance is occurring, an alternative solution would be required. Otherwise, the interruption to consumers' power supply would be very significant – likely to be 200 to 250 hours per year if historical patterns are sustained.

The lowest cost alternative solution is likely to be stand-by diesel generators, which would be run only when required to maintain continuity of local supply. Based on recent published data for such plant, we estimate the total cost would be around $17 million in present value terms to provide local cover equivalent to the Tekapo A station over a 35-year period. This cost would presumably need to be met by local power consumers, given that no other group would obtain appreciable benefits from such expenditure.

This cost estimate is likely to be conservative because it assumes a solution that is sized to meet the existing need. In fact, electricity demand in the Tekapo Albury region is expected to grow, especially in the Tekapo basin where approximately 20% growth in peak demand is projected by Transpower by 2038.[27] The estimate is also based on 'off-the-shelf' costs for diesel generators, and some additional expenditure is likely to be required to allow plant to perform frequency keeping duty.

We have also considered an alternative solution based on batteries. These are expected to be around 30% more expensive than diesel generator back-up if installed today (in present value terms). Battery costs are trending down, and batteries may eventually become cheaper than a diesel back-up solution. However, that position may not be reached for some time.

In summary, in addition to its contribution to national electricity supply, the Tekapo Power Scheme contributes significant regional benefits by providing power to consumers in the Tekapo Albury region when it is periodically cut-off from the rest of the grid. Without the Tekapo A station, an alternative electricity source would need to be developed. This would be expected to have a total cost of around $17 million in present value terms, otherwise consumers in the local area would likely experience power cuts for 200 to 250 hours per year.

[26] See Transmission Planning Report 2023, section 18.5.2.
[27] See Transmission Planning Report 2023, section 18.2.1.

4.7 Tekapo Power Scheme lowers electricity prices for consumers

The previous sections have estimated the economic costs arising from the avoided capital, operating, and fuel costs of the electricity supply resources that would otherwise need to be built and operated if the Scheme needed to be replaced.

This section estimates the benefit to New Zealand electricity consumers in terms of avoiding the electricity price increases that would occur if the Scheme needed to be replaced.

In simple terms, prices in the New Zealand electricity market arise as follows:

- Transpower (in its role as the System Operator) forecasts electricity demand for each half-hour of each day.
- Electricity generators (such as hydro dams, wind farms, and gas-fired power stations) then offer electricity to meet the projected demand for each half-hour.
- These offers are ranked from the lowest to the highest priced and placed in a stack.
- Transpower then select offers from the cheapest to the most expensive in each half hour until enough offers have been selected to meet demand.
- The price of the highest offer selected sets the market price for that half hour.
- All demand pays that market price, and all selected generators get paid the market price.[28]

If the water for the Tekapo Scheme was not available, the power it would have generated will need to come from alternative sources. By definition, such sources will be higher-priced, as they would otherwise have displaced the Tekapo Scheme generation.

The nature and scale of price effect is likely to be different in the short term than in the long term.

Short-term price effect

If the loss of the Scheme's generation is not signalled many years in advance, the market will not have time to adjust to the loss by building new supply assets to replace the Scheme's output. Accordingly, there will be a greater number of periods where very high-priced resources will be setting the market price: predominantly high-priced thermal stations (mainly gas-fired OCGTs and the diesel-fired Whirinaki station) plus some even higher-priced demand-side curtailment.

Long-term price effect

In the long term, the market can respond to the loss of the Scheme's generation by building new supply assets to the point where a new supply / demand equilibrium has been re-established. Average prices in a market in supply / demand equilibrium should equilibrate to the long-run marginal cost (LRMC) of the marginal new entrant generator. In New Zealand, this is likely to be either wind or solar generation, with the LRMC being the levelised cost of energy (LCOE) of such plant, factored by the cost of firming output from such variable renewables during periods where the wind is not blowing, or the sun is not shining.

In both the with- and without-Tekapo 'worlds', wind and solar are likely to be the marginal new entrant generation technologies that drive average market prices. At first glance, this might appear to suggest that long-run market prices would be the same in both such worlds, and the loss of the Tekapo Scheme would have no effect on long-term market prices. However, there are two factors which mean this is not the case:

[28] This simple explanation ignores the fact that there are generally regional variations in the market price, driven by transmission losses and (at times) transmission constraints. However, for the purposes of this high-level analysis, we can ignore this complication.

Firstly, there is an upward-sloping cost-supply curve for potential new renewable projects. Thus, variations in the following factors result in material differences in the cost of power from the best project compared to the worst project:

- quality of the renewable resource (eg, wind speed),
- local geophysical characteristics and the subsequent civil engineering costs to access the resource, and
- costs of connecting to the electricity network, driven by variations in the proximity to the network and extent of spare capacity on that part of the network.

Losing generation from the Tekapo Scheme will require a greater amount of new renewable projects to be developed than would otherwise be the case, pushing New Zealand up the renewable cost-supply curve.

Secondly, the greater the proportion of a renewable technology on the system, the greater will be the proportional costs to firm the output for that technology, raising average market prices. Losing generation from the Tekapo Scheme would result in the market having a greater proportional mix of wind and solar on the system than would otherwise be the case, and consequently greater firming costs.

Estimate of the scale of short-term and long-term effect on market prices from the loss of power from the Tekapo Scheme

It was beyond the scope of this report to undertake the detailed market modelling necessary to directly estimate the market price effect of the loss of Tekapo Scheme generation in both the short and long term.

However, to estimate the likely scale of effect we have drawn upon market modelling undertaken by Concept for its most recent electricity price forecast report.[29] As well as producing a central price forecast, the report undertook a number of sensitivities to test the price outcomes arising from various parameters being greater or less than our central estimates. One such parameter was demand being greater or less by approximately ±1,000 GWh, with such analysis being undertaken for two years:

- 2027, being a year where the market would have little time to adjust the build of new generation in response to the altered demand
- 2037, being a year sufficiently far in the future that the market could adjust through altering the build of additional renewables.

We have used these demand variation sensitivities as a basis for estimating the potential scale of price effect from losing the approximately 1,870 GWh of output from the Tekapo Scheme.

Using this approach, we estimate the short-term effect of the loss of the Tekapo Scheme output would be for market prices to increase by approximately $60/MWh. This very large price increase reflects the fact that, if the market does not have time to adjust to the loss of such a large amount of generation, supply security will be degraded, and significant amounts of demand curtailment will be incurred.

The long-term effect is for market prices to be approximately $7.5/MWh higher than they would otherwise have been. The fact that the long-term price effect is lower than the short-term price effect is because the long-term consequence of the loss of the Tekapo Scheme will predominantly be the need to build more expensive renewables and call upon greater amounts of firming, rather than greatly increasing the extent of demand curtailment.

We have combined these short- and long-term estimates of the price effect of the loss of the Tekapo Scheme with projections of consumer demand, in order to estimate the overall increase in cost to New Zealand consumers if the output from the Tekapo Scheme were to be lost.[30]

[29] *"NZ electricity price forecasts"*, 15 January 2025, Concept Consulting Ltd. Report available for purchase on request.
[30] Our projections are for demand to be 43% higher than current levels by 2050, and 64% higher by 2075.

Using an 8% discount rate, the present value of the aggregate increase in costs to New Zealand consumers over 35 years is estimated to be $9.2 billion.

5 Conclusion

The Tekapo Power Scheme provides significant national benefits to the power system by generating substantial volumes of 100% renewable electricity. In energy terms, the Scheme's average annual output (from both direct and indirect generation) is sufficient to supply around 228,000 average Canterbury households – over 80% of the number of homes in the Canterbury region in 2023 according to StatsNZ.

Replacing the Scheme's output with alternative renewable sources would impose additional costs on society of around $170 to $220 million per year. Furthermore, it would take time to construct the alternatives, creating a need for increased thermal generation in the meantime. The annual costs for that generation would be approximately $250 to $370 million per year. The increased thermal generation would also significantly raise New Zealand's greenhouse gas emissions, by the equivalent of 450,000 to 1.13 million cars per year while it was operating.

The Scheme also provides significant national benefits through its ability to vary its energy output to match system conditions. This helps to maintain reliable electricity supply to consumers. The cost estimates above are expected to be conservative because they do not account for the economic premium that applies to controllable generation sources.

The Scheme provides significant regional benefits to the Tekapo region by providing a power supply when the area is cut off from the national grid, avoiding a choice between 200-250 hours per year without electricity supply or spending around $20 million in present value terms for alternative measures to ensure security of supply.

Finally, the Scheme provides a national benefit to New Zealand electricity consumers by avoiding electricity price increases that would occur if the Scheme needed to be replaced. Replacing the Scheme would require more expensive generation in the short term, leading to price increases of around $60/MWh. In the long term, the development of more expensive renewables would be required, equating to price increases of around $7.5/MWh. These price increases equate to a present value increase in costs to consumers of approximately $9.2 billion.