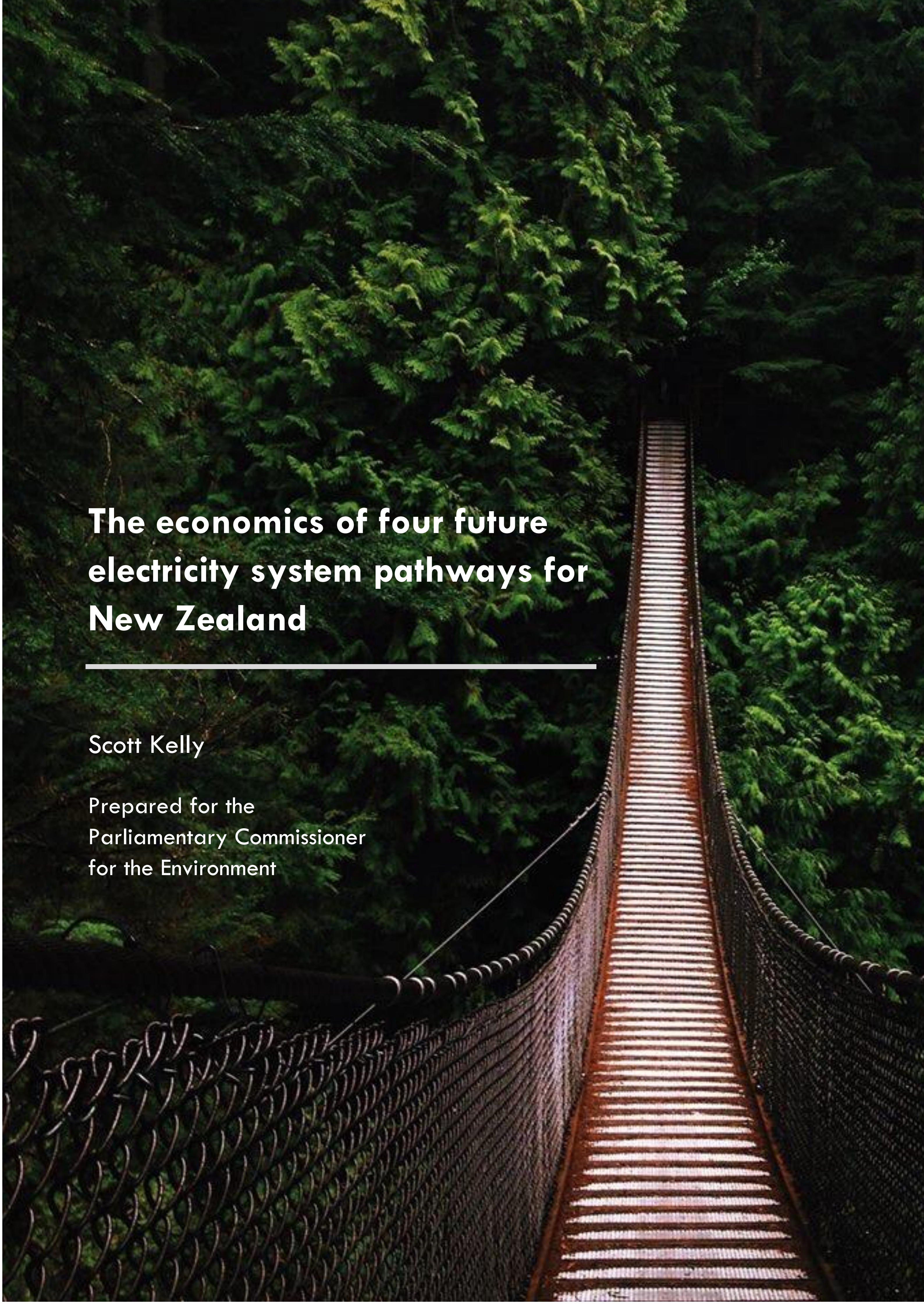
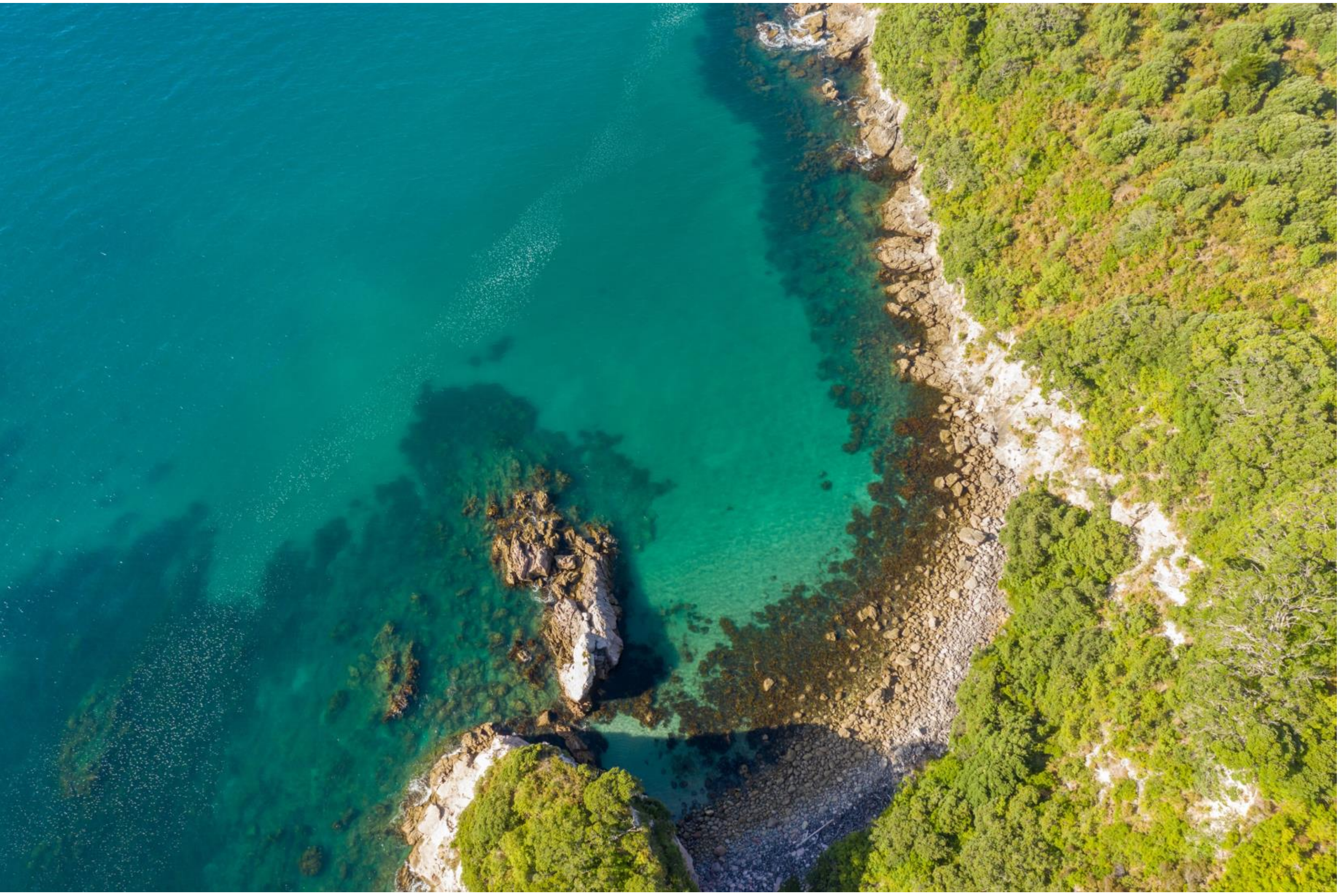


The economics of four future electricity system pathways for New Zealand

Scott Kelly

Prepared for the
Parliamentary Commissioner
for the Environment



8th June 2023

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Summary

Energy Link was commissioned by the Parliamentary Commissioner for the Environment to model the system wide effects of four transformational electricity pathways actively being considered in New Zealand. The coming energy transition represents a once in a generation opportunity to establish a low carbon, affordable and secure electricity system for decades to come. The importance of decisions that are made over the next several years cannot be underestimated for the likely impacts they will have on the environment, economy, society and the climate. While this analysis focuses on the system wide economic and electricity price impacts, a comprehensive environmental assessment for each of the different pathways is still required.

The four pathways considered in this analysis are (0) base case market response; (1) Tiwai Point aluminium smelter closes; (2a and 2b) the introduction of Southern Green Hydrogen and; (3) Lake Onslow pumped hydroelectricity storage (PHES). The suite of Energy Link models used for this analysis utilise well established market dynamics and economic principles to estimate investment in new generation and future wholesale electricity prices. Model outputs provided by Energy Link were analysed and synthesised to assess a range of electricity system characteristics. For each pathway this analysis estimates future CO_2 emissions, wholesale market price volatility, energy security, wholesale electricity prices and final electricity prices for residential, industrial, commercial and agricultural consumers. It also assesses the system wide economic costs and benefits of each pathway under a range of different sensitivity settings.

Pathway 0: Base case market response is a business as usual (BAU) pathway that assumes the electricity system continues under standard operating and market conditions. This pathway is used to benchmark the relative costs and benefits of the other three pathways modelled.

Pathway 1: Tiwai Point aluminium smelter closes has the most immediate effect on residential electricity prices and emissions. In this pathway, benefits exceed costs and Tiwai Point meets the benchmark of a positive Net Present Value (NPV) over the model period.

Pathway 2: Southern Green Hydrogen is one of the poorest performing pathways across a range of indicators. Residential electricity prices remain high, and it is shown to be the worst pathway for providing energy security as measured by the level of security of supply risk quantified by the supply of last resort (SLR) in the system. All hydrogen pathways (2a and 2b) return a negative NPV over the modelling period across all cost of capital assumptions and discount rates, indicating that the social benefits of this pathway do not outweigh the costs under the range of sensitivity tests conducted.

Pathway 3: Onslow pumped hydroelectricity storage is the only pathway that effectively suppresses seasonal market volatility, thus driving down wholesale electricity prices and providing increased predictability over future electricity prices to the market. This pathway produces lower residential electricity prices than the base case, even after the cost of constructing Onslow has been taken into account and added to consumer electricity bills. The additional charge to consumers is estimated at between 1.73 c/kWh to 0.11c/kWh depending on the range of sensitivity tests assumed. The Onslow pathway also returns a positive NPV for all but the highest cost of capital and discount rate scenarios, suggesting further analysis into Onslow is warranted based on its ability to reduce seasonal wholesale electricity prices when compared to other scenarios. Onslow is shown to have system wide economic benefits at an economic cost of $15 billion and a real WACC[1] of 2% (nominal WACC of 5%) across all discount rates. Under these conditions, Onslow is shown

[1] WACC – Weighted average cost of capital represents the firm's average cost of capital weighted to reflect that different sources of capital carry different return expectations.

to lower average annual electricity bills by up to $150[2] by 2050, whilst also providing system wide support for dry year risk and security of supply.

With the effective carbon price rising to $250 per tonne by 2050[3], this results in significant investment in renewables across all scenarios. By 2050 all scenarios – including the base case – achieve over 98% of total electricity generation coming from renewables. Contrary to popular belief, very high penetration of renewables, when coupled with a robust security of supply strategy, was not shown to have a detrimental effect on the economics of those scenarios with higher levels of renewable electricity generation.

This analysis confirms that long-lived infrastructure projects are particularly sensitive to the financial assumptions being used. Given that pumped hydroelectricity dams are expected to last for 100 years or more, the effects of using different asset lifetimes were tested for different discount rates. Both 50-year and 100-year modelling periods were compared for Onslow. When a 100-year modelling period was assumed, the cost benefit calculations improved the financial viability for long-lived assets, when compared to assets with much shorter lifetimes (when using appropriate cost of capital and discount rate assumptions).

Sensitivity analysis was also completed on weighted average cost of capital estimates. Once again, long-lived assets with large upfront capital demands were more sensitive to differences in assumptions about the weighted average cost of capital than short-lived assets. Undertaking unbiased comparisons between assets with different lifetimes therefore requires the full life of the asset to be included in financial assessments. This requires that the cost of assets with shorter lifetimes are replaced within the modelling period, which is allowed for in the analysis.

This analysis did not include the costs associated with electricity outages or extended periods of reduced electricity supply in dry year situations. Estimating the costs of supply disruption is problematic as it depends on the extent of any prior warning provided, the duration of the outage and at what time of day the outage occurs. Each of these factors will result in different costs to different users in the electricity system. In this analysis we make use of the supply of last resort (SLR) metric as a proxy for security of supply. This analysis suggests that Onslow would reduce system wide outage costs by up to $130 million per year when compared to the base case, assuming a typical $10,000 per MWh supply of last resort cost. The economic cost of widespread and extended electricity supply shortages as might happen in a dry year, is potentially very significant, so this is a lower bound estimate for this type of risk. These costs (savings) were not included in any of the cost benefit calculations presented in this report. If they were, they would improve the economics of Onslow even further. A deeper and more rigorous analysis of the risks and costs associated with different forms of outages would be a valuable contribution to the estimation of dry year risk and the increasingly volatile electricity supply market.

In conclusion, this analysis has shown that model results are highly sensitive to the modelling assumptions used in the analysis, and therefore to any final conclusions drawn. Being open and transparent about the extent of input assumptions and undertaking a range of sensitivity tests is therefore very important for any future modelling exercises. Such analysis should be published and available for public scrutiny. Assumptions relating to the cost of capital, asset lifetimes, discount rates, upgrades to transmission and distribution infrastructure and operation and maintenance expenditure are critical input assumptions that must be subjected to a range of sensitivity tests across all plausible pathways.

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[2] This assumes an average electricity consumer from Christchurch consumes 7,261 kWh per year in electricity.

[3] As per recommendations from the Climate Change Commission to achieve New Zealand's net zero targets.

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Introduction

The Parliamentary Commissioner for the Environment commissioned Energy Link to undertake four electricity price pathways to understand how decarbonisation of the electricity system may evolve over the next three decades under different policy and market assumptions. The construction of a pumped hydroelectricity storage (PHES) dam at Lake Onslow; decommissioning of the Tiwai Point aluminium smelter; and the development of a large Southern Green Hydrogen (SGH) project in the South Island all represent markedly different energy futures with resulting impacts on the environment, climate and end consumers. The pathways were developed using Energy Link's I-Gen model[4] which simulates the decision-making processes of market participants for the investment and operation of different generation technologies connected to the National Grid. Energy Link's EMarket model was used to model nodal daily electricity prices across the electricity network out to 2050.

The decarbonisation of New Zealand's electricity generation system will play a key role in putting New Zealand on a pathway to achieving net zero carbon emissions by 2050. While the emission reduction potential of the four pathways is examined, assessing the wider environmental and social impacts of these pathways was out of scope. If any of these options are taken forward, then full environmental and social impact assessments will be required.

The Pathways

The following pathways were modelled to 2050:

Pathway 0: Tiwai Point remains operational and market demand and prevailing economic conditions continue as normal. New renewable and peak generating capacity is added to the grid as it is required to meet forward demand projections under standard market assumptions, including a carbon price rising from around $50 today to $250 by 2050.

Pathway 1: The Tiwai Point aluminium smelter is shut down and electricity from Manapouri hydro dam flows into the grid, this has the effect of lowering electricity prices for end consumers, accepting that there will be constraints on the grid, some spill and other inefficiencies. However, under this pathway less new renewable development is required to meet demand thus putting downward pressure on electricity prices.

Pathways 2a and 2b: Tiwai Point remains operational alongside a new Southern Green Hydrogen (SGH) project. An option fee is paid to the hydrogen plant to curtail hydrogen production and provide flexible demand to the grid, and if necessary to completely shut down in a dry year, the fee paid to SGH to curtail demand is assumed to be passed onto consumers via higher electricity prices. Hydrogen is exported overseas, thus requiring the construction of additional renewable electricity generation plants to meet demand. Two pathways are developed to assess the potential for different operational configurations. In the first pathway (2a) SGH will operate in continuous mode without the option of providing flexible demand reduction or shutting down in a dry year. The second pathway (2b) will provide flexible grid support and shut down completely if required during a dry year. The difference in operating costs will be used to estimate the total annual option fee. The two pathways are as follows:

Pathway 2a. this pathway is run with SGH dispatched fully at all times;

Pathway 2b. this pathway is run with SGH bidding to provide dispatchable demand at a definite pre-specified contract price.

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[4] Energy Link. 2022. Residential Electricity Price Pathways to 2050. Report to Parliamentary Commissioner of the Environment.

Pathway 3: Tiwai Point is not shut down and Onslow is built. Lake Onslow supports the grid by pumping when prices are low and generating when prices are high. This has the effect of reducing the volatility of electricity prices as well as reducing wholesale electricity prices over the long term. The construction cost of Onslow is factored into electricity prices where the full costs of construction, maintenance and operation are assumed to be passed onto all end consumers as an additional charge on electricity bills. Because of uncertainty around construction costs and sensitivity to financial parameters, a detailed sensitivity analysis is undertaken for a range of financial parameters.

Modelling assumptions

Modelling inputs and assumptions are based on relevant inputs from Energy Link's Price Path modelling. The primary output of the Energy Link modelling is an estimate of residential electricity prices based on changes to generation technology under each of the four electricity pathways. Model outputs from the Energy Link pathways were used to examine different electricity system characteristics such as emissions, security of supply, affordability and wholesale electricity prices. Criteria such as the risks of meeting demand in a dry year, market volatility and future emissions were all explored.

Timeline and resolution

The Energy Link model adopts the full range of all 91 historical water inflow pathways that date back to 1930[5]. Wind and sun pathways date back to 1980 and are assigned randomly to inflow years prior to this. Two key nodes on the electricity network were chosen to represent two different points on the national grid, one in the South Island and one in the North Island[6]. The North Island node is located just outside of Auckland (OTA2) and the South Island node (ISL2) is located just outside Christchurch. For each pathway, average daily wholesale electricity prices at each node were estimated until 2050.

Demand

Future demand is modelled as the Climate Change Commission's (CCC) "Tiwai Point stays with certainty" pathway[7]. Demand projections from Pathway 0: Tiwai Point stays with certainty pathway were taken from the Climate Change Commission where the smelter continues to operate, and renewables are developed unconstrained. The demonstration pathway was used to set the first three emissions budgets and only included technologies that were considered technically viable. It is therefore likely to be a low estimate of electricity demand in 2050 as it is expected that other technologies will become available, enabling industries to electrify even further. Consistent with the Climate Change Commission's demand pathway a consistent interpolation of demand between now and 2050 is assumed. The only difference in future demand projections across the different pathways was in Pathway 1: Tiwai Point closes, in this pathway demand is reduced by the equivalent demand requirements of the Tiwai Point smelter.

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[5] The energy-link model uses historical weather data including, wind, rain, and sunshine hours dating back 91 years to estimate forward projections for renewable energy availability.

[6] The modelled grid has 220 nodes.

[7] Inaia tonu nei: a low emissions future for Aotearoa. 2021. Climate Change Commission. https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/

The rate of demand growth across all pathways reflects the amount of electrification that is required to meet net zero targets, particularly from the mid 2030s which is higher than the average growth rate between 1974 to 2006.

As shown in

Figure 1, between 1974 and 2006, demand growth was consistently around 700 GWh per annum increasing from 30,000 GWh to 40,000 GWh per annum. Between 2006 and 2022 demand growth then plateaued. Forward projections from 2022 have demand growth exceeding 700 GWh per year until 2050, this growth accounts for the expected demand growth in electrification across the economy. This may have the effect of pushing prices higher in the Energy Link model as the build simulator tends to lag demand growth. Another factor is through the LCOE (levelised cost of energy) of building new generation. As the future electricity price is expected to rise, it will mean more expensive plant will be built earlier than it otherwise would.

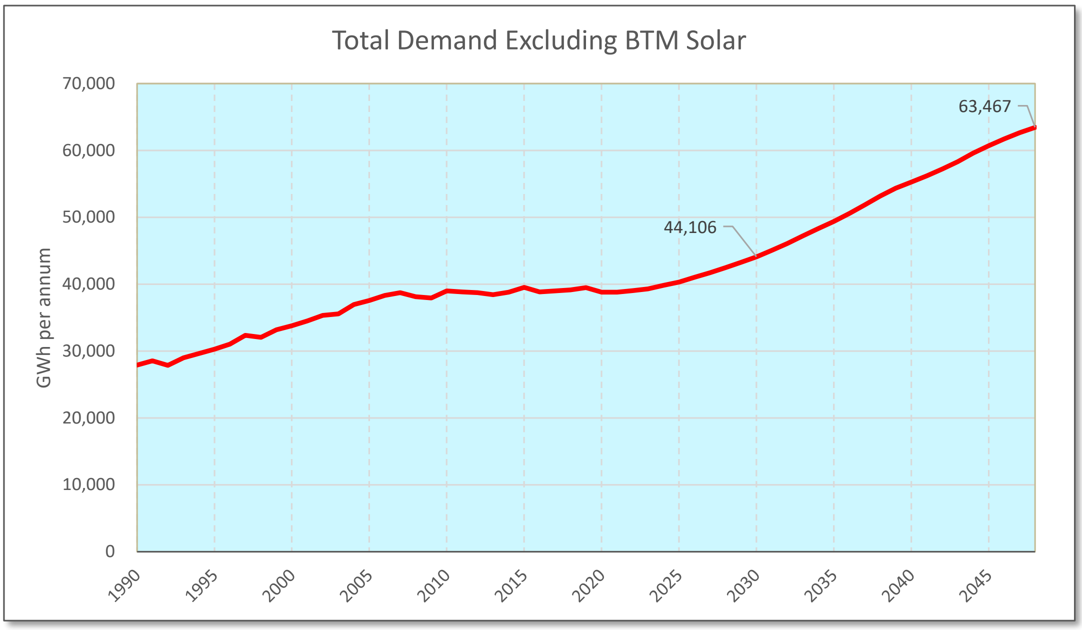

Figure 1: Projected demand growth

Carbon prices

The future carbon price was estimated from published forward projections from the Climate Change Commission[8]. These are not forecasts but estimate what the future carbon price would need to be if the New Zealand economy was to decarbonise by 2050. The Climate Change Commission prices do not reflect New Zealand emission units (NZU) prices, but rather the price that would be incurred in the wider economy in a net zero by 2050 pathway. For the purposes of these pathways we assume the New Zealand Emissions Trading Scheme carbon price reflects the broader price paid by the economy in a net zero by 2050 pathway. The carbon price is presently trading at $53 per NZU, therefore this price is assumed to rise to $250 per NZU by 2050 to meet future net zero targets. Figure 2 shows the assumed growth in carbon prices between 2020 and 2050.

[8] Draft Advice for Consultation. 2021. Climate Change Commission. https://haveyoursay.climatecommission.govt.nz/comms-and-engagement/future-climate-action-for-aotearoa/supporting_documents/CCCADVICETOGOVT31JAN2021pdf.pdf

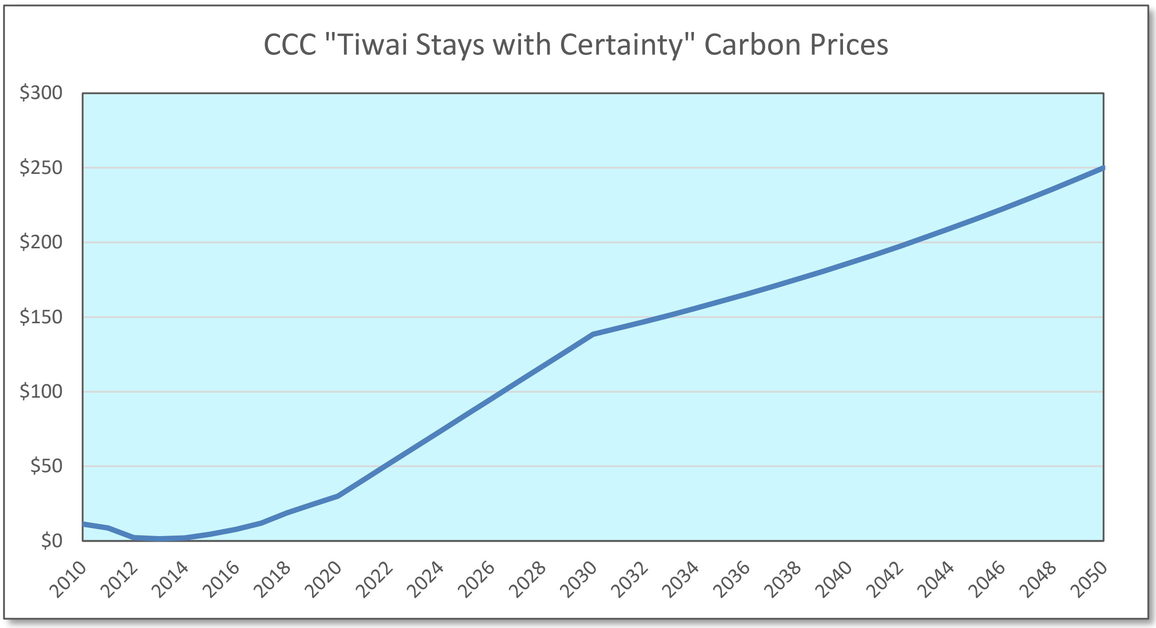

Figure 2: Forward carbon price projections

Renewable electricity targets

This modelling did not implement any hard renewable targets for any pathway. Based on input assumptions, all pathways meet a minimum 95% renewable threshold by 2030, as recommended by the Climate Change Commission.

Financial analysis

All analysis and prices presented in this report are calculated in real values rather than nominal values. This provides a more accurate and realistic view of financial performance over time by removing the effects of inflation from the analysis.

Outputs for Onslow were shown to be sensitive to the weighted average cost of capital (WACC), the period over which capital costs are recovered and the discount rate. Therefore, four sensitivity scenarios were assessed. The Commerce Commission guidelines[9] on the use of WACC for network infrastructure used by EDBs and Transpower range from 3.78% to 4.13% - while the Commerce Commission's report does not make clear if these values are nominal or real values, the standard approach when calculating WACC is to use nominal values. As this analysis was completed in real values (taking away the effects of inflation), the WACC vales chosen for this analysis are also represented in real terms. Values for WACC were chosen at 2% and 5% which would correspond to a nominal WACC value of 5% and 8% assuming a 3% rate of inflation (or a nominal WACC of 8.7% for real WACC of 2% given the prevailing inflation rate in March was 6.7%). This is much higher than the rates recommended by the Commerce Commission and therefore considered conservative.

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[9] Commerce Commission. 2019. Cost of capital determination.
https://comcom.govt.nz/__data/assets/pdf_file/0022/177034/2019-NZCC-12-Cost-of-capital-determination-EDBs-and-Transpower-25-September-2019.PDF

Each pathway was sensitive to the financial assumptions being used. The cost of constructing Onslow is still unknown but recent estimates put construction costs in the range of around $15 billion[10]. While the capital cost is significant, it must be weighed against the savings in electricity prices to end consumers resulting from lower generation costs, reduced price volatility in the wholesale market, a reduction in system wide risks and its contribution to lower emissions compared with the alternatives. It is thus most useful when the costs and benefits of Onslow are compared directly with a base case pathway where Onslow does not exist and the market continues under business as usual (BAU). Table 1 lists the different sensitivity tests that were included for each of the different pathways.

Table 1: Onslow sensitivity testing

Sensitivity scenario	CAPEX $Billion	WACC (real)	Period
Pathway 2: SGH – low [11]	$0.75	2%	30 years
Pathway 2: SGH – high	$0.75	5%	30 years
Pathway 3: Onslow - low-50 years	$15.0	2%	50 years
Pathway 3: Onslow - low-100 years	$15.0	2%	100 years
Pathway 3: Onslow - high-50 years	$15.0	5%	50 years
Pathway 3: Onslow - high-100 years	$15.0	5%	100 years

Natural gas price

Natural gas prices were taken from the latest natural gas forecast price used by Energy Link[12]. These prices were higher in the short term than normal due to Pohokura supply and coal issues. The forecast price then reverts back to more steady state production levels as gas reserves run down. Meeting future instantaneous demand shortfalls will be achieved using gas-peakers, which will run on some form of gas with costs similar to the forecast natural gas price.

LCOEs

The levelised cost of electricity (LCOE) for different generation technologies are provided by Energy Link and updated to actual builds where information is available in the public domain. Data on grid scale solar farms is usually proprietary and not shared, thus Energy-Link have used best available information. Recent developments such as rising interest rates, rising inflation and supply chain issues have caused LCOE nominal assumptions to rise significantly. In real terms, however, LCOEs for wind and solar continue to fall due to learning curve effects and rising manufacturing volumes. As we are comparing prices across different pathways the important thing is that the LCOEs for each generation technology remain consistent across the different pathways.

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[10] Feasibility study report: NZ battery project, Lake Onslow Pumped Storage Scheme. 2023. MBIE. https://www.mbie.govt.nz/dmsdocument/26293-feasibility-study-report-nz-battery-project-lake-onslow-pumped-storage-scheme-volume-8-appendix-m-september-2022-pdf

[11] The cost of electrolysers for the Southern Green Hydrogen project will have an assumed capital cost of $750 million with a replacement life of approximately 30 years.

[12] Energy Link. 2022. Residential Electricity Price Pathways to 2050. Report to Parliamentary Commissioner of the Environment.

Scarcity threshold and supply of last resort (SLR)

Scarcity pricing refers to the notion of increasing electricity prices above the marginal cost of the marginal unit under conditions where the system is short on generation capacity. The scarcity price threshold remains at $10,000 per MWh, which is in line with the value currently recommended by the Electricity Authority and Industry Participation Code[13]. It is also the value used and recommended by Energy Link when assessing SLR risk.

Onslow

There is a lot of uncertainty about the cost and timeline regarding the construction and commissioning of the Onslow pumped hydroelectricity storage facility. The infrastructure commission released a report[14] "leveraging our energy resources to reduce global emissions and increase our living standards" which provides an estimated timetable for the construction and commissioning of Onslow. It presents an estimated timeline of between 8 and 10 years before the facility can generate power once a decision has been made. This timeline was later confirmed in a Cabinet paper presented by MBIE in February 2023[15]. If a decision is made in 2025 it will take two years to tender and award a contract, seven years to build and at least three years to fill. It is assumed that Onslow could generate electricity and provide some dry year support while it was still filling.

In line with NZ Battery modelling, it is assumed that Onslow could have a generating capacity up to 1.5GW[16] and store 8,500 GWh of potential energy. However, for the purposes of this modelling a generating capacity of 1 GW is assumed, and hold up to 5,000 GWh of electricity. This is in line with the most recent recommendations from MBIE to cabinet[15].

The final operating regime for Onslow has not yet been decided. For the purposes of these pathways, we assume Onslow will operate as part of the electricity market, it will therefore take its water values from its interactions with the market rather than having a schedule of exogenous prices applied.

The construction cost of Onslow remains highly uncertain with estimates that range from $4 billion to over $15 billion[17]. In this modelling, the capital cost of constructing Onslow will be recovered through revenue and a fixed charge on consumer electricity bills for each kWh of electricity consumed.

Green hydrogen production

This pathway assumes a new hydrogen production facility is developed in Southland (SGH). This is in line with a tender process that was launched and managed by Meridian in 2022 to attract a commercial partner to build and operate a hydrogen production plant in Southland. This pathway assumes that Tiwai Point remains operational and the Aluminium smelter participates in demand side flexibility. All hydrogen is assumed to be exported overseas. The hydrogen production facility thus leads to an overall net increase in electricity demand on the grid averaging around 4,060 GWh per year or between 6% and 10% of total aggregate demand. It is assumed the cost of electrolysers are around $1.5 million per MW and 500 MW of electrolysers

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[13] Electricity Authority. The Electricity Code. 2022. https://www.ea.govt.nz/operations/wholesale/spot-pricing/scarcity-pricing/ (the code)

[14] https://www.tewaihanga.govt.nz/strategy/infrastructure-reports/leveraging-our-energy-resources-to-reduce-global-emissions-and-increase-our-living-standards/

[15] MBIE Cabinet Paper. 31st March 2023. https://www.mbie.govt.nz/dmsdocument/26297-new-zealand-battery-project-progressing-to-the-next-phase-proactiverelease-pdf

[16] https://www.mbie.govt.nz/dmsdocument/23346-update-on-the-new-zealand-battery-project-proactiverelease-pdf

[17] https://www.interest.co.nz/public-policy/118875/nz%E2%80%99s-proposed-pumped-storage-hydropower-project-will-cost-billions-%E2%80%93-here%E2%80%99s

are installed at a cost of $750 million[18,19]. Electrolysers are assumed to have a life of 30 years with a target capacity factor of 77%.

Upgrade of HVDC link

The current capacity of the high-voltage direct current (HVDC) link between the North and South Island is a constraint on Onslow's ability to help meet peak demand in the North Island. It is assumed the HVDC link is upgraded to 1400 MW north prior to Onslow being commissioned. The upgrade of the HVDC is being investigated independently of Onslow being built[20]. Across all pathways demand-side response (DSR) and batteries will be added to help meet demand in the North Island on cold, calm winter evenings and during dry periods.

Other common assumptions

Apart from the capacity of the HVDC link and other permanent constraints limiting power flows into the lower and upper South Island, and lower and upper North Island, the grid is run unconstrained, which assumes the grid[21] will be upgraded progressively over time as demand grows across the network.

This assumption is valid because many renewable generation projects are in regions where the grid needs upgrading to allow them to produce to plan, and without these upgrades, electrification cannot and will not occur at the rate and to the degree required to decarbonise by 2050. For a list of additional assumptions please review Appendix A.

Method

This modelling exercise uses pathways to compare four distinct electricity system pathways to 2050. The base case pathway assumes the electricity sector is left alone and new generation is built using market conditions to meet future demand expectations. This pathway is therefore a continuation of existing conditions (Tiwai Point remains) with minimal government intervention or regulation with no big investment from the private sector in hydrogen production. The model is not forced to reach net zero emissions by 2050, nor are there any assumptions about reaching 100% renewables at any point in time. This was so the characteristics of the different pathways could be compared on an even-footing.

New generation in each pathway is built on Energy Link's I-Gen model which simulates the decision-making processes of generators as they relate to building new generation. The basic principle behind this model is that new generation is committed when it achieves the target EBITDA within a defined number of years of commissioning, taking into account costs, location on the grid and the expected output profile of the generation technology[22]. Each of the other three pathways assesses the independent price impacts of other major system interventions (e.g. Tiwai Point smelter closing, green hydrogen production facility for export and

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18 The UK government undertook a comprehensive estimate on the capital cost of hydrogen electrolysers. This analysis showed that electrolyser CAPEX costs ranged from $1,200 to $2,400 per MW. We assume a lower end of the range. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf

19 A similar study in the US found CAPEX costs ranged from US$1000 to US$2,600 in 2020. https://theicct.org/wp-content/uploads/2021/06/final_icct2020_assessment_of-_hydrogen_production_costs-v2.pdf

20 https://www.transpower.co.nz/projects/hvdc-submarine-cable-replacement-and-enhancement-investigation

21 Grid upgrades include the addition of new poles and wires, but also infrastructure to improve power quality such as reducing voltage fluctuations, harmonic distortions, and other smart grid technology to improve control.

22 Any differences between the pathways with respect to investment confidence is largely speculative and so this has not been modelled in any of the pathways.

the development of Onslow pumped hydroelectricity). These pathways were chosen because they are under active consideration and will each have a substantial impact on the environment and climate over the coming decades.

Energy Link's Emarket model was used to model the electricity market to 2050 with 220 nodes across the grid with prices at each node. The prices at two nodes are reported here, one in Auckland (OTA2) and one in Christchurch (ISL2). These are used as proxies for the wholesale prices in the North and South Island respectively. The model itself can be resolved at sub-daily resolution but for this modelling only average daily prices were estimated using day-night resolution. The model uses a market-based dispatch approach for all generation and includes detailed models of all major hydro river chains and lakes for water value optimisation. All monetary values in this report are in constant 2022 New Zealand dollars, unless otherwise stated.

Modelling results

Pathway 0: Base case

The base case pathway represents a business as usual scenario and is used to compare market effects across the different pathways. It assumes business as usual operation without major changes to demand or supply and allows the market to respond to economic signals to build new capacity as and when required. Figure 3 shows installed generation capacity by source. In this pathway total system generation capacity is shown to approximately double from 9.7 GW in 2023 to 18.8 GW in 2050 with the majority of this increase (8.2 GW) coming from wind and solar. The total installed capacity of thermal generation decreases from 1.86 GW in 2023 to 1.16 GW in 2050 as old fossil fuel generation plants are decommissioned and not replaced. Figure 4 shows total annual electricity generation by source. Annual total generation is predicted to increase from 41 TWh in 2023 to 63 TWh in 2050 – an almost 50% increase. Thermal generation decreases from 4 TWh to 1 TWh while wind and solar generation increase from 3.7 TWh in 2023 to 22.6 TWh in 2050. Even in this base case pathway, renewables supply 95% of total electricity demand by 2030 and increasing to 96.5% of total supply by 2050.

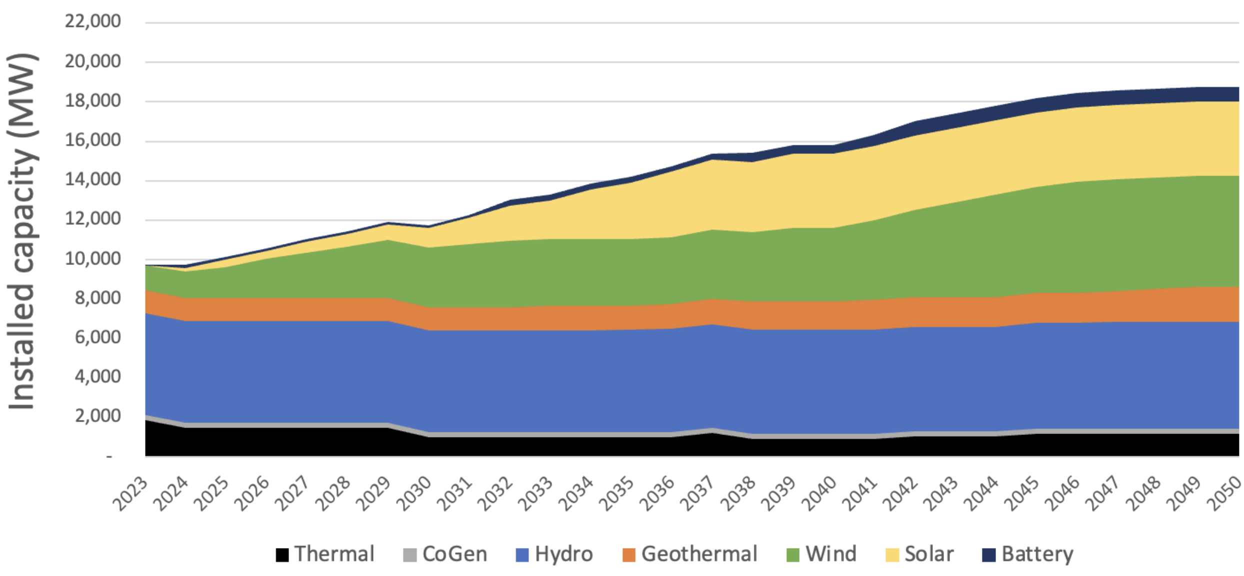


Figure 3: Pathway 0 (Base Case) – Installed generation capacity by source (MW)

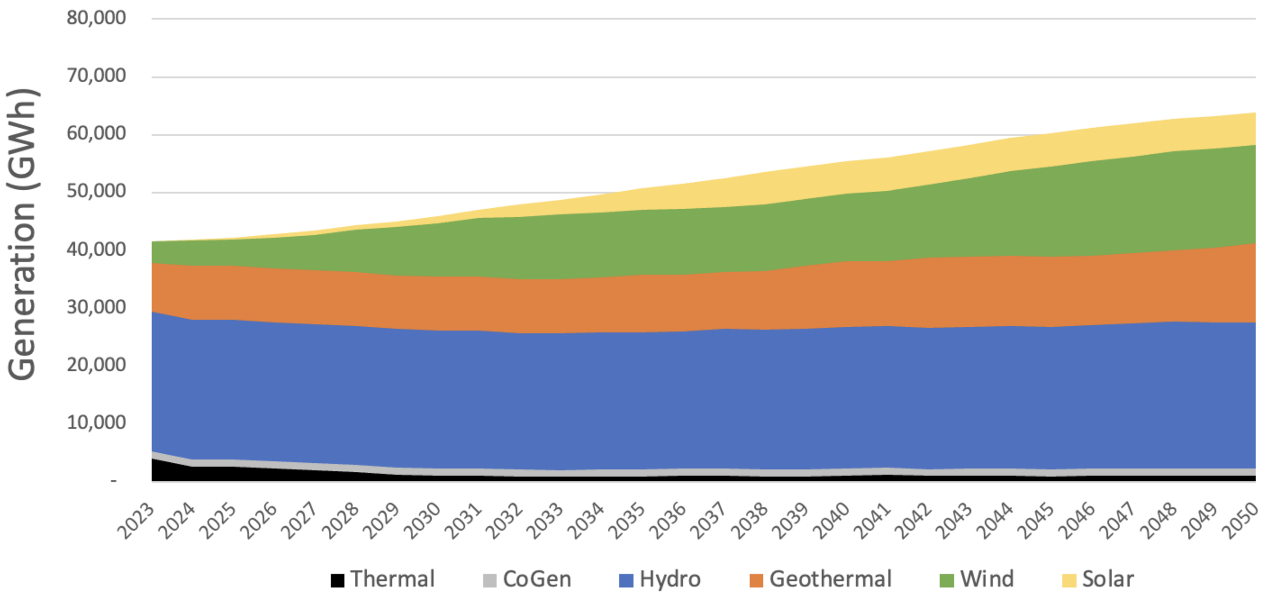


Figure 4: Pathway 0 (Base Case) – Electricity generation by source (GWh)

In this pathway emissions drop from an average of 3.5 $MtCO_2$ in 2023 to 2.56 $MtCO_2$ in 2050. This occurs as thermal generation is decommissioned, and new renewable generation is developed.

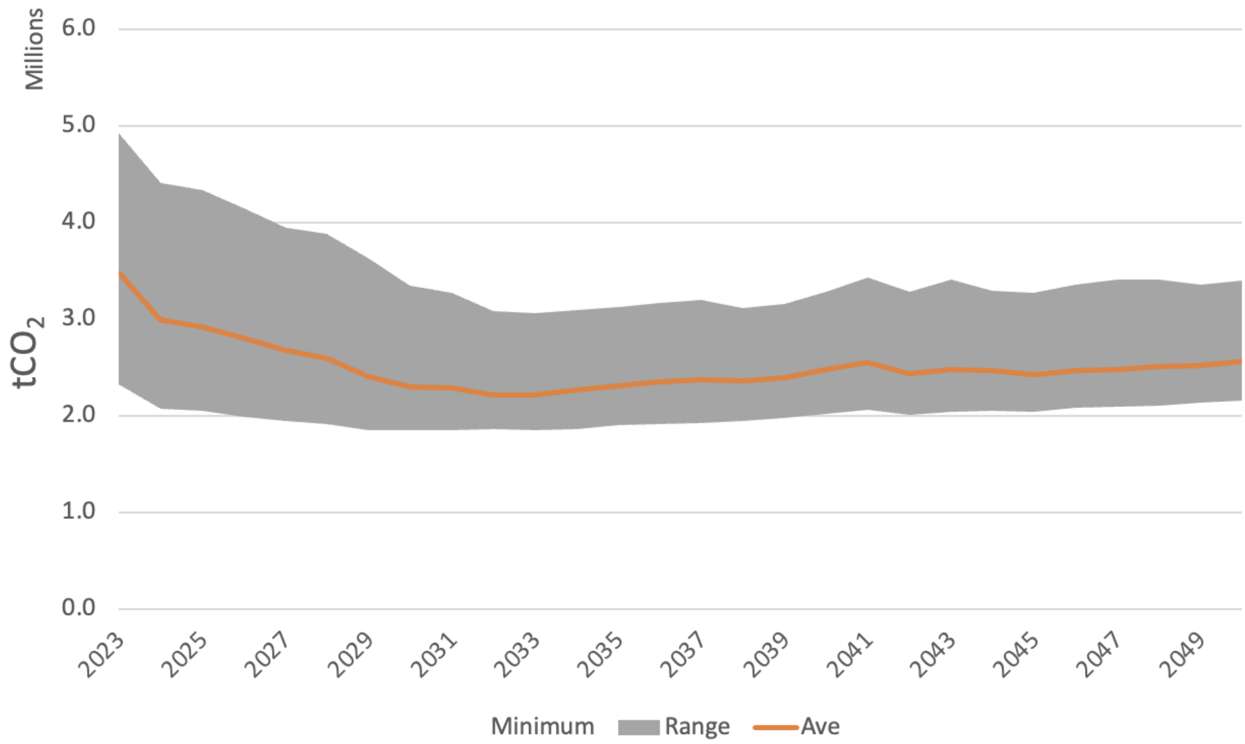


Figure 5: Pathway 0 (Base Case): Total emissions

Pathway 1: Tiwai Point closes

This pathway is the same as the base case pathway except that Tiwai Point is assumed to shut down, allowing the Manapouri hydroelectricity dam to dispatch electricity into the national grid. This effectively frees up 572 MW of capacity to be dispatched into the wider grid resulting in most of the output of the West Arm power station at Manapouri flowing northward. Total installed capacity in this pathway increases from 9.8 GW in

2023 to 16.9 GW by 2050 – which is 1.8 GW less than the Base Case pathway. Electricity generation increases from 41.6 TWh to 59.2 TWh by 2050. Emissions decrease from an average of 3.4 $MtCO_2$ to 2.4 $MtCO_2$ in 2050. This pathway has the largest immediate drop in emissions because the additional electricity dispatched to the grid displaces carbon intensive fossil fuel generation (see Figure 8). However, after the initial drop in emissions they remain relatively stable over the modelling period. Renewables reach 95.3% of total electricity generation in 2030 increasing to 96.5% by 2050.

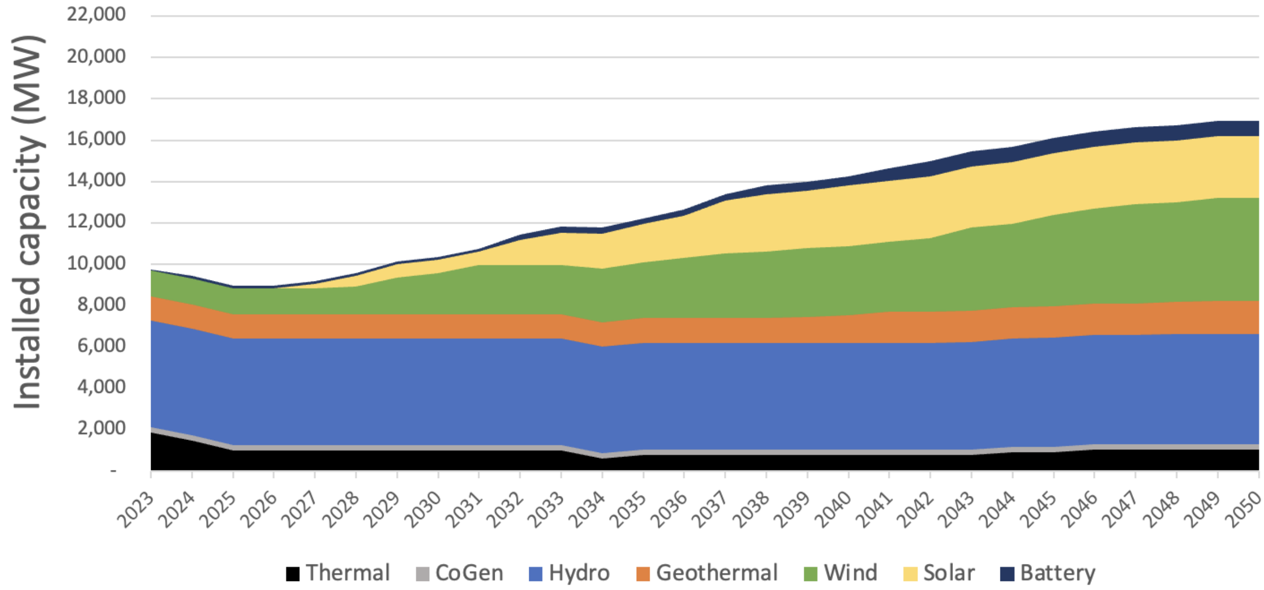


Figure 6: Pathway 1 (Tiwai Point closes) Total installed capacity (MW)

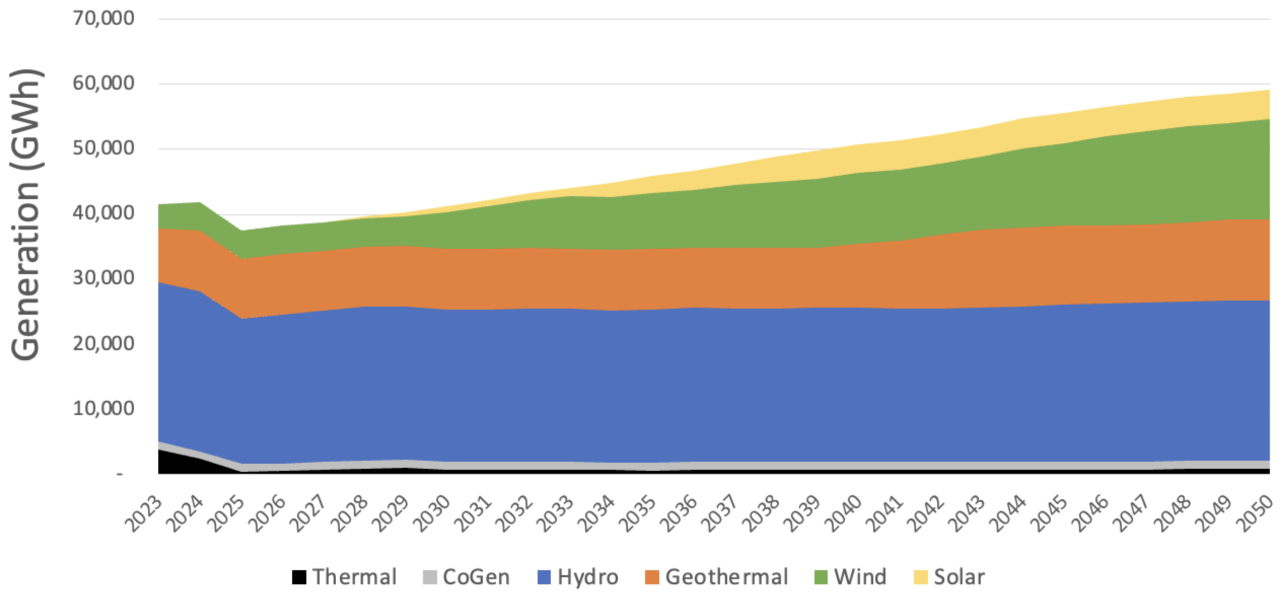


Figure 7: Pathway 1 (Tiwai Point closes) Total generation (GWh)

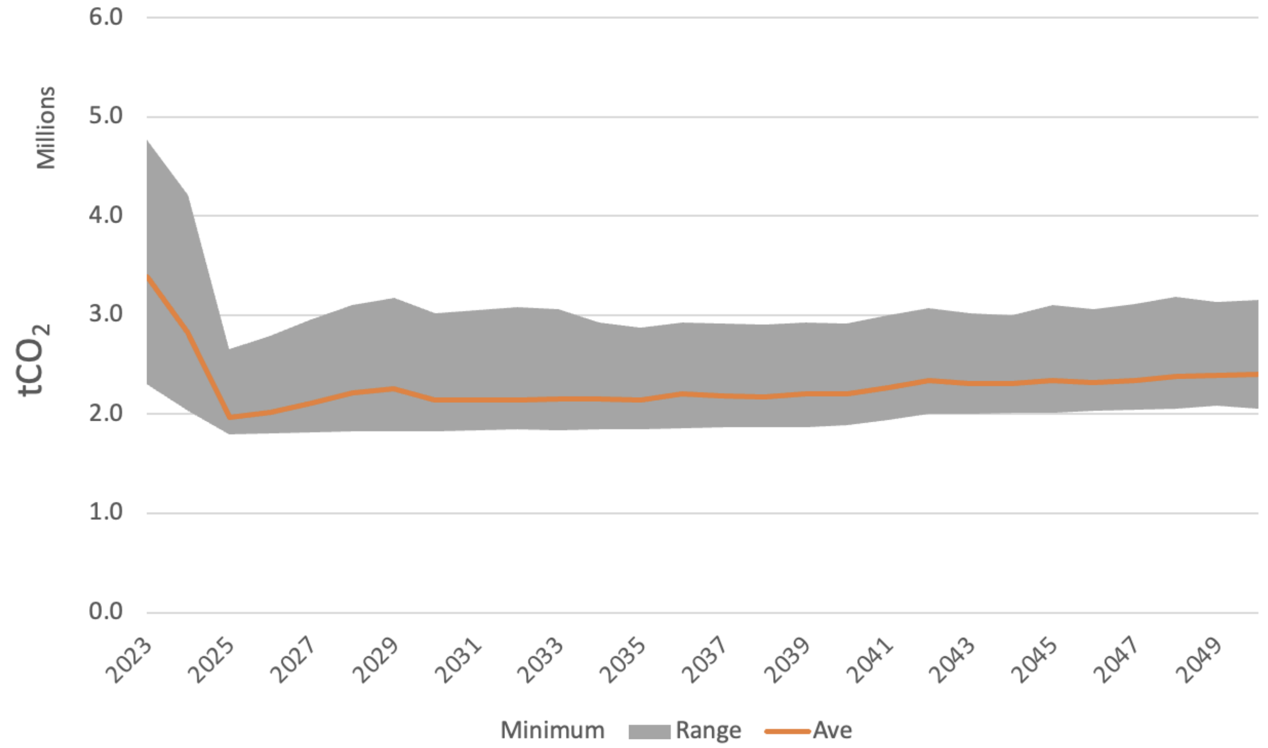


Figure 8: Pathway 1 (Tiwai Point closes) Total emissions

Pathway 2a & 2b: Southern Green Hydrogen

Pathways 2a & 2b represent two contrasting views for the operation of a new green hydrogen plant located in Southland. In Pathway 2a SGH operates as baseload and does not vary its demand in response to market prices. In Pathway 2b SGH bids demand into the spot market and is dispatched accordingly. Bid prices are adjusted to achieve an average capacity factor of 77%. With both SGH and Tiwai Point operating in the South Island, a substantial amount of new wind generation is required to support this new demand that is not built in the other pathways. This is shown in Figure 9 where the installed capacity of wind generation increases by almost a factor of four over the next decade going from 1.2 GW in 2023 to 4.5 GW in 2031, twice the rate of increase in the base case.

In Pathway 2a, total demand in the South Island is so great it causes the Southland voltage stability constraint to be triggered, placing into question whether a large hydrogen generation plant can co-exist in Southland alongside the Tiwai Point aluminium smelter without substantial grid upgrades. For the sake of modelling, it is assumed that Transpower upgrades the grid in the South Island to increase supply capacity constraints – the costs of these upgrades have not been included as part of the cost estimates for this pathway.

In Pathway 2a total installed capacity grows from 9.7 GW in 2023 to 20.3 GW in 2050. The increase in generation capacity in Pathway 2b is slightly less, increasing from 9.7 GW to 19.6 GW in 2050. In Pathway 2a total generation increases from 41.5 TWh in 2023 to 69.3 TWh in 2050, while in Pathway 2b total generation increases to 68 TWh. Average emissions in both pathways decrease from 3.5 MtCO_2 in 2023 to 2.7 MtCO_2 in Pathway 2a and to 2.4 MtCO_2 in Pathway 2b (See Figure 14). The range in emissions is higher in Pathway 2a, reflecting less certainty about more variability to achieve emissions reductions. In Pathway 2a renewables reach 95.1% of total electricity generation by 2030 and 96.3% by 2050. In Pathway 2b, renewables reach 95.5% of total generation by 2030 and 97.1% by 2050.

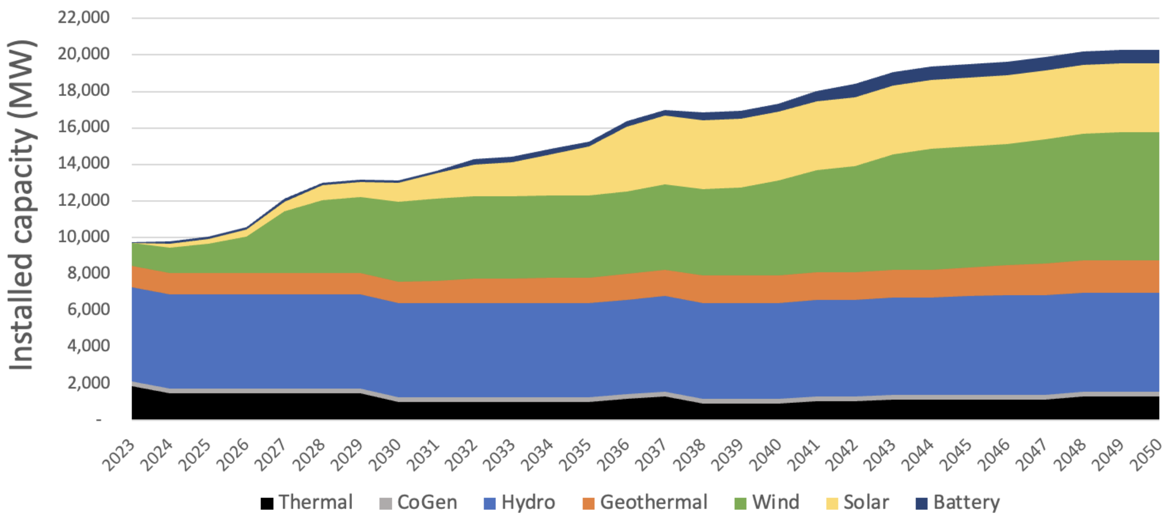


Figure 9: Pathway 2a (fixed hydrogen) – Total installed capacity (MW)

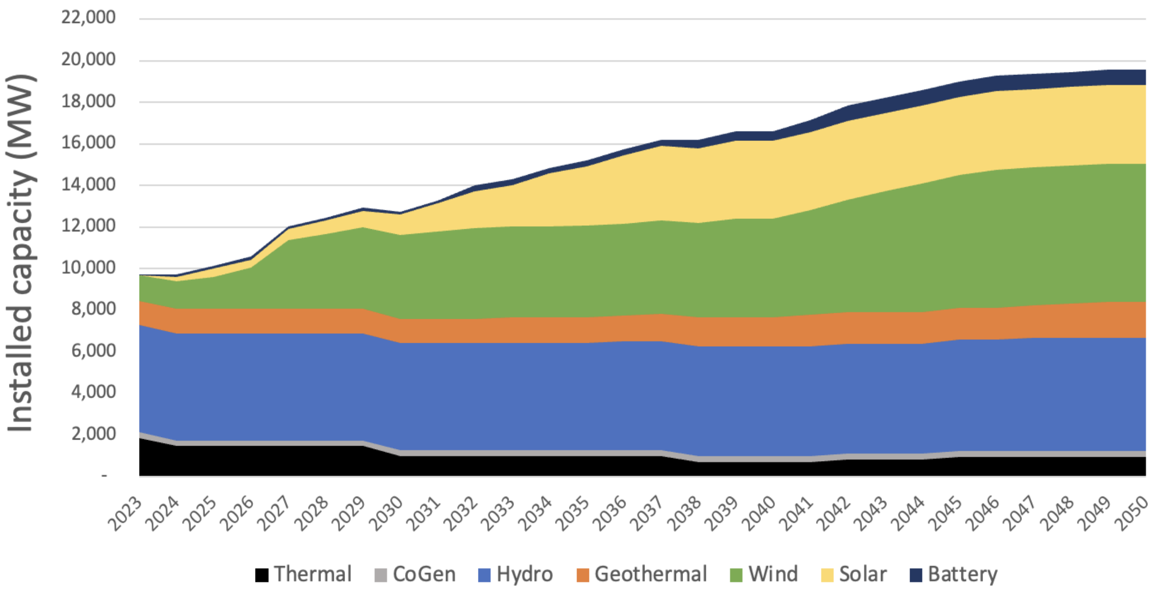


Figure 10: Pathway 2b (SGH Variable) Total installed capacity (MW)

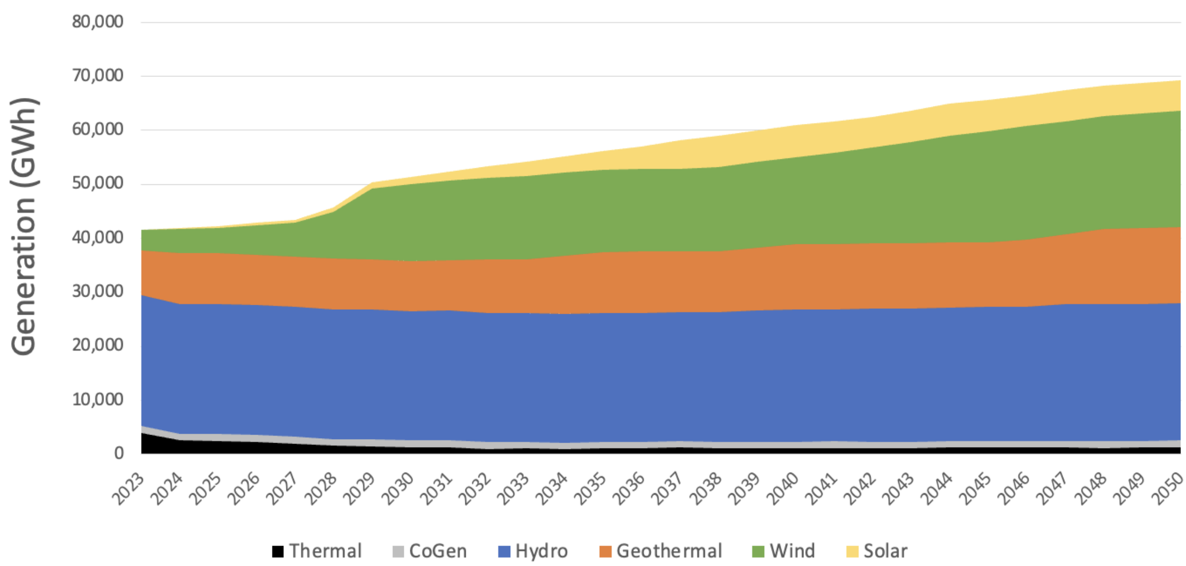


Figure 11: Pathway 2a (fixed hydrogen) Total generation (GWh)

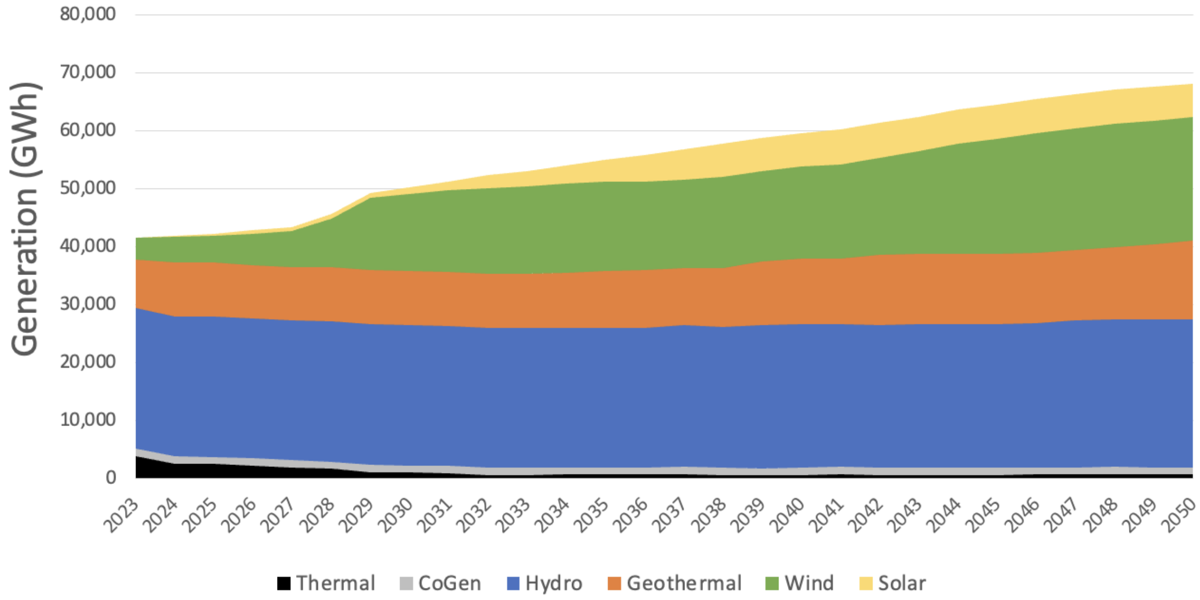


Figure 12: Pathway 2b (SGH Variable) Total generation (GWh)

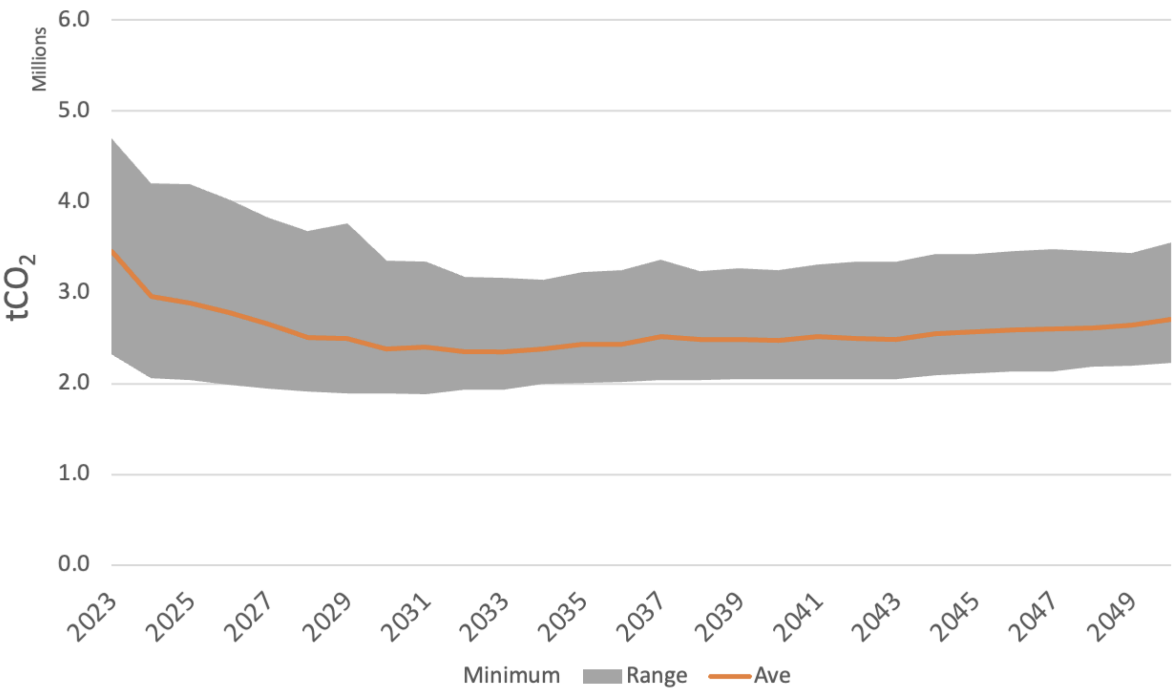


Figure 13: Pathway 2a (Fixed Hydrogen) – Total Emissions

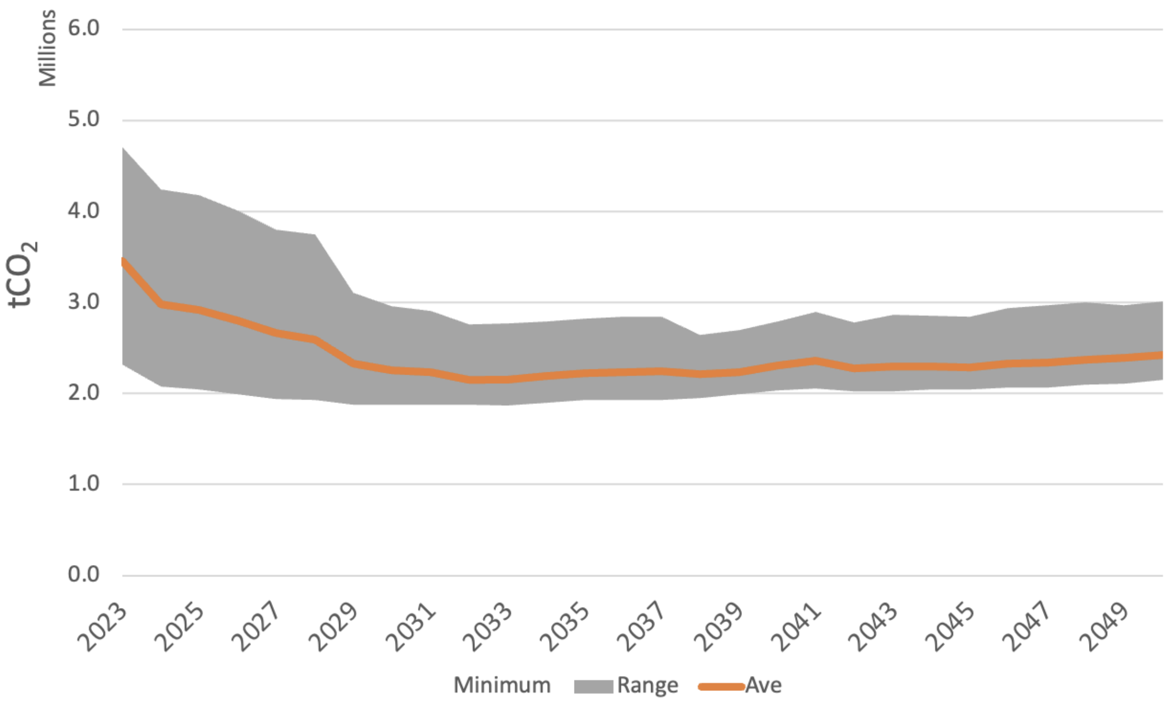


Figure 14: Pathway 2b (Variable Hydrogen) – Total Emissions

Pathway 3: Onslow pumped hydroelectricity storage

It is assumed that the Lake Onslow pumped hydroelectricity scheme is commissioned and operational from 2031. It then takes an average of another two to three years to completely fill to a point where it can be operating normally. It is assumed that Onslow can hold 5,000 GWh of potential storage with 1,000 MW of generating capacity. The length of time Onslow takes to fill is dependent on system wide operating conditions such as whether New Zealand is in a wet or dry year at any time. Wet and dry years arise from the 91 historical inflow water value time-series within the Energy Link model. Figure 15 shows the storage capacity of Onslow for each of the 91 historical water inflow years. Positive values represent charging while negative values represent discharging.

The percentiles on Figure 15 represents the probability of reaching a given level of dam capacity. For example, the area represented by the 80th percentile shows where the level of the dam (generation capacity) will be exceeded one in every five years. This chart also shows that on average Onslow fluctuates between a charge of 2,000 GWh and 3,500 GWh, a range of about 1,500 GWh per year. The annual net output of Huntly is around 5,000 GWh, which means under normal operating conditions the expected output of Onslow is around 30% of the generation capacity of Huntly. In a dry year it would discharge from an average peak of around 3,500 GWh of capacity to around 500 GWh of capacity. A range of around 3,000 GWh, which is around the capacity that is required in a typical dry year. Indeed, this modelling shows from historical inflow data, the dam can indeed meet a typical dry year shortfall. The output also shows that when the dam is operating purely under market conditions, the average height of the dam (capacity) starts to gradually decline from around 2039. This suggests there is substantial potential to optimise the operation of the dam with improved interannual, medium-term weather and climate predictions. For example, periods of La Niña and El Niño would provide opportunities for multi-year charging and discharging of the dam to improve system wide operation across the electricity network. This modelling did not include operating Onslow based on interannual weather predictions but such analysis is expected to substantially improve the economics of Onslow.

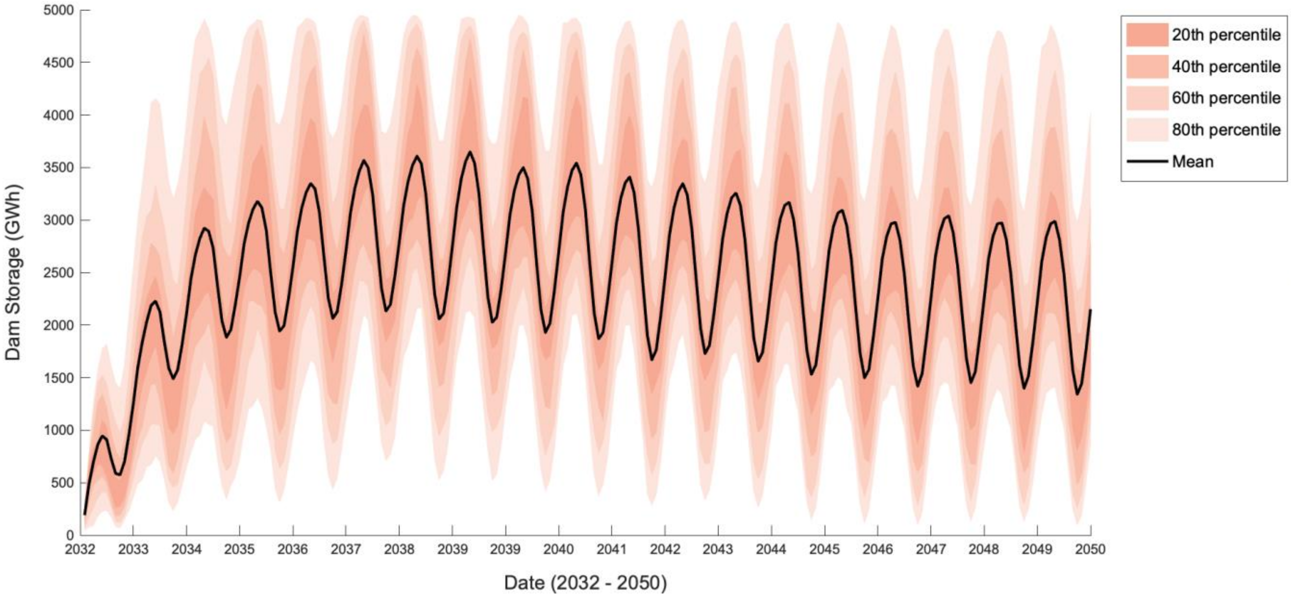


Figure 15: Monthly storage trajectories across all 91 historical time series

This pathway includes the cost of constructing, operating and maintaining Lake Onslow. After revenue has been deducted, a fee is levied as a fixed cost per kWh of total delivered electricity across all consumers. We only model a planned HVDC link upgrade of 1,400 MW to match North Island peak demand with remaining peak support provided by other flexible generation resources coming online, using similar assumptions to the other pathways.

In this pathway total installed generation capacity increases from 9.7GW to 19GW in 2050, with over 85% of new generation coming from wind and solar (Figure 16). Total generation from wind and solar increases from 3.7 TWh to 25 TWh over the next 28 years, representing a significant increase in intermittent and variable generation coming onto the grid (Figure 17). Emissions in the Onslow pathway decrease from 3.5 $MtCO_2$ in 2023 to 2.3 $MtCO_2$ in 2050, the largest emissions reductions across all pathways (Figure 18). Renewables reach 94.9% of total electricity generation by 2030 and 97.7% by 2050.

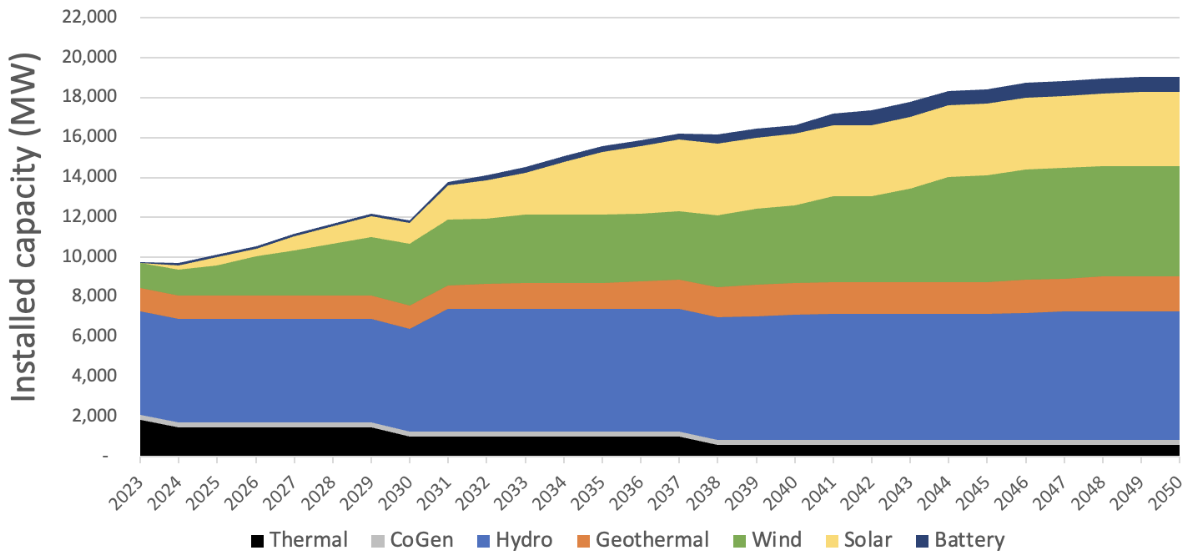


Figure 16: Pathway 3 (Onslow) Total installed capacity (MW)

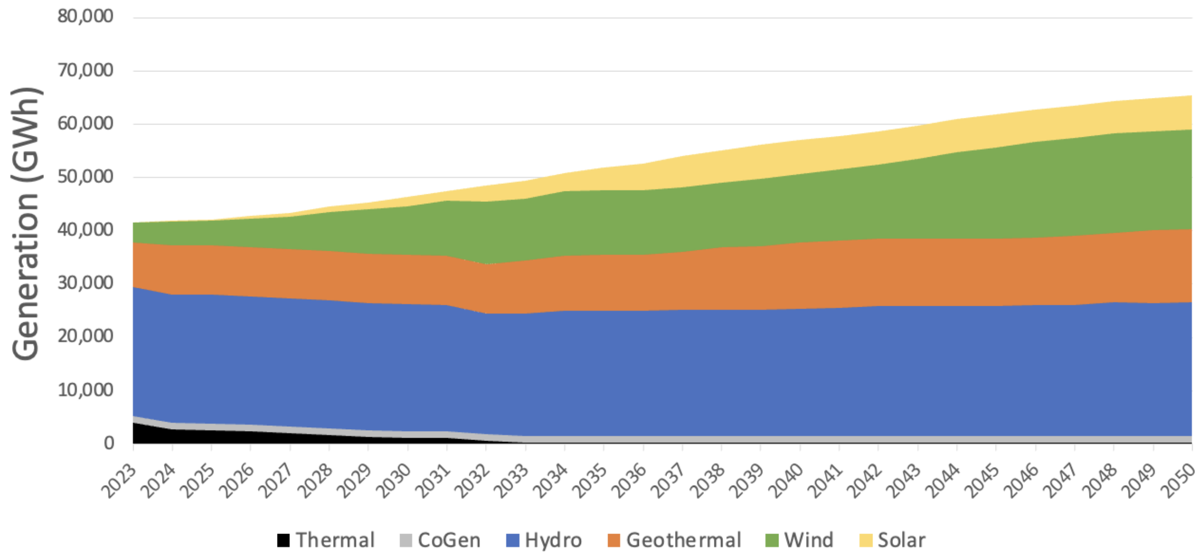


Figure 17: Pathway 3 (Onslow) Total generation (GWh)

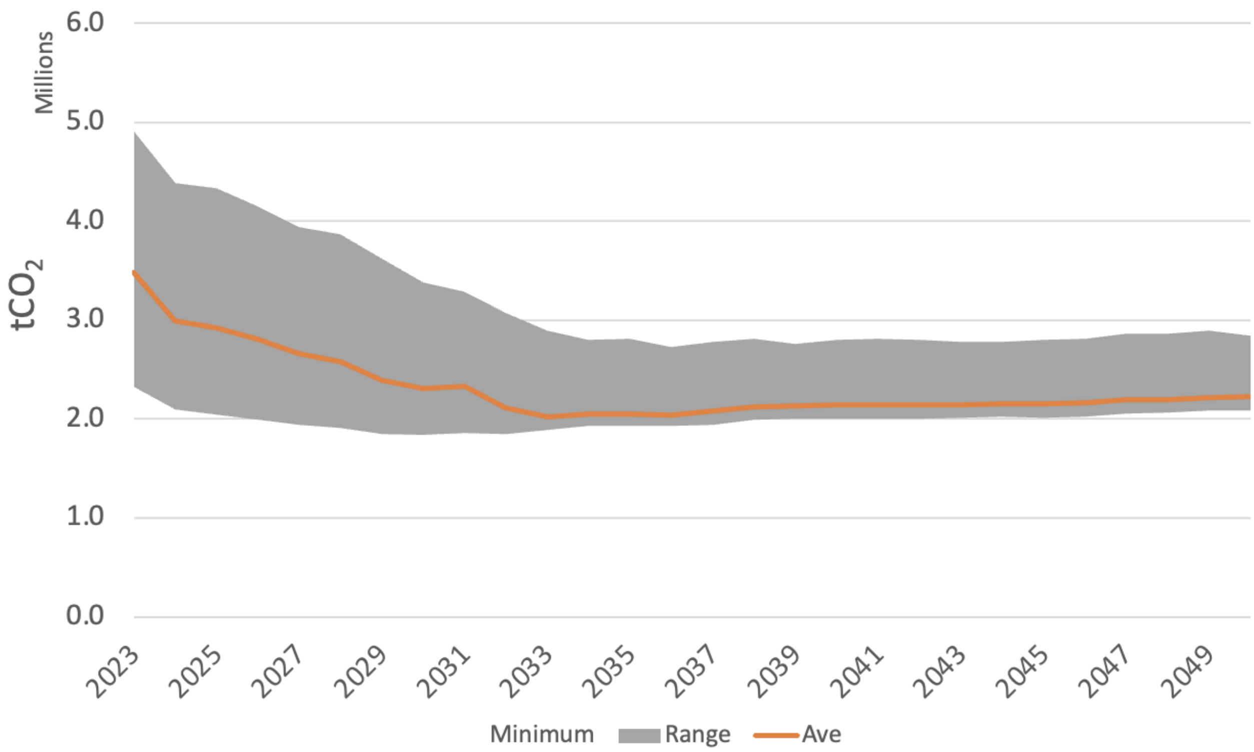


Figure 18: Pathway 3: (Onslow) – Total Emissions

It is assumed that all gas-fired peakers that exist in the market at the time of Onslow's commissioning remain in the market, but no new gas-fired peakers are built once Onslow is commissioned. This is because they are not required once Onslow is operational and able to meet peak demand. Onslow is modelled using the same water value optimisation techniques employed by the large hydro market participants. This ensures that Onslow operates in an optimal fashion, i.e. water coming into the electricity supply system is rationed in a way that minimises the total system cost of meeting electricity across the network. The only difference with Onslow is that it also consumes electricity when it is in pumping mode, which is also optimised based on water values and the prevailing market conditions. Using this approach Onslow constantly calculates the prices at which it will charge (pumping water from the Clutha) and discharge (generate electricity and release water into the Clutha). This means that Onslow will charge when prices are low and generate when prices are high.

The price and times at which Onslow will pump or generate are not fixed as the decision to pump or generate Takes into account other system wide information.

Onslow responds to market signals during peak demand periods and prolonged dry periods and can switch from pumping to generating over the course of a single day. On average, however, across 91 future model runs, Onslow operates on a seasonal basis, pumping when hydro-lakes are full and renewable power is plentiful, generally pumping from October to February and then generating electricity from April through September. This seasonality in generation and pumping is shown in Figure 19.

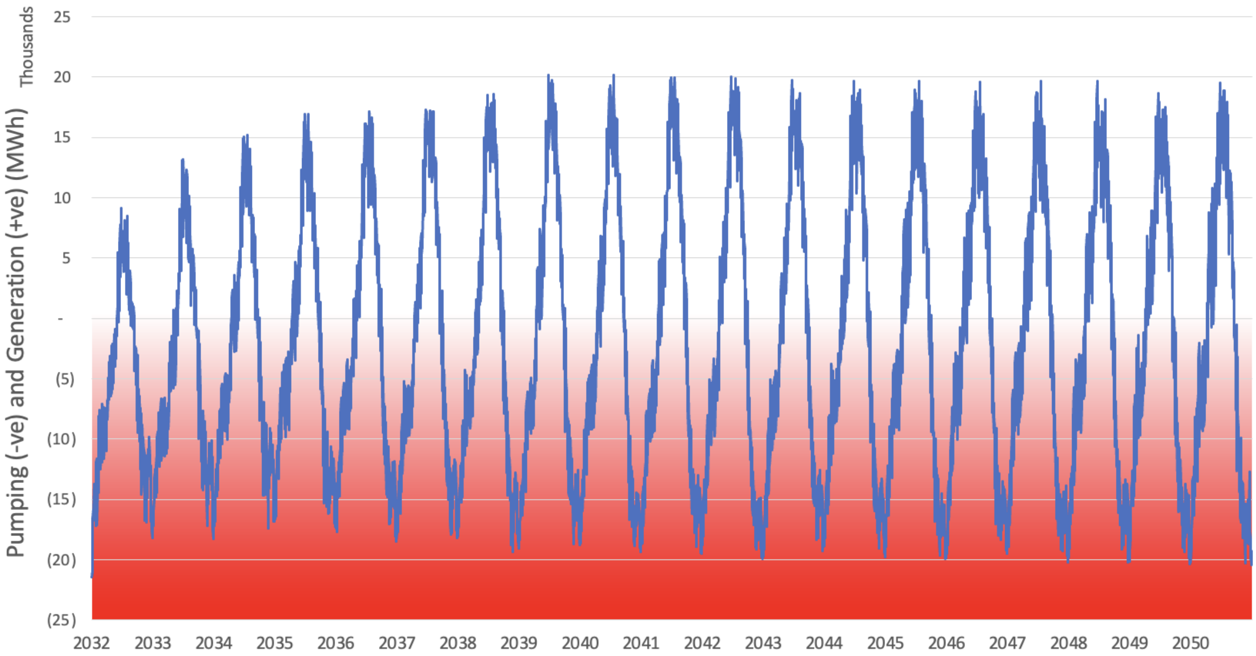


Figure 19: Onslow average daily pumping and generation cycles across all model runs

Because electricity prices are high when Onslow is generating and prices are low when Onslow is pumping, revenue and costs can be plotted in a similar way. As more renewables come online, and as we move closer to 2050, the volatility in electricity prices will continue to increase, driving up the difference between costs and revenue thereby increasing the profitability of the pumped hydroelectricity being produced at Onslow. This can also be seen in Figure 20 where the net revenue (generation revenue minus pumping costs) gradually increases as electricity markets become increasingly volatile owing to the growing quantity of intermittent and variable electricity resources coming online. Average daily revenue increases from a peak of $1-2 million in the early 2030s to $5-6 million per day by the 2040s (in constant 2022 dollars)[23].

[23] We assume nodal prices are taken from nodal prices at ISL2 near Christchurch. This node was chosen to represent wholesale electricity prices in South Island and represents the revenue potential after grid upgrades had occurred allowing for unconstrained electricity supply between Onslow and Christchurch.

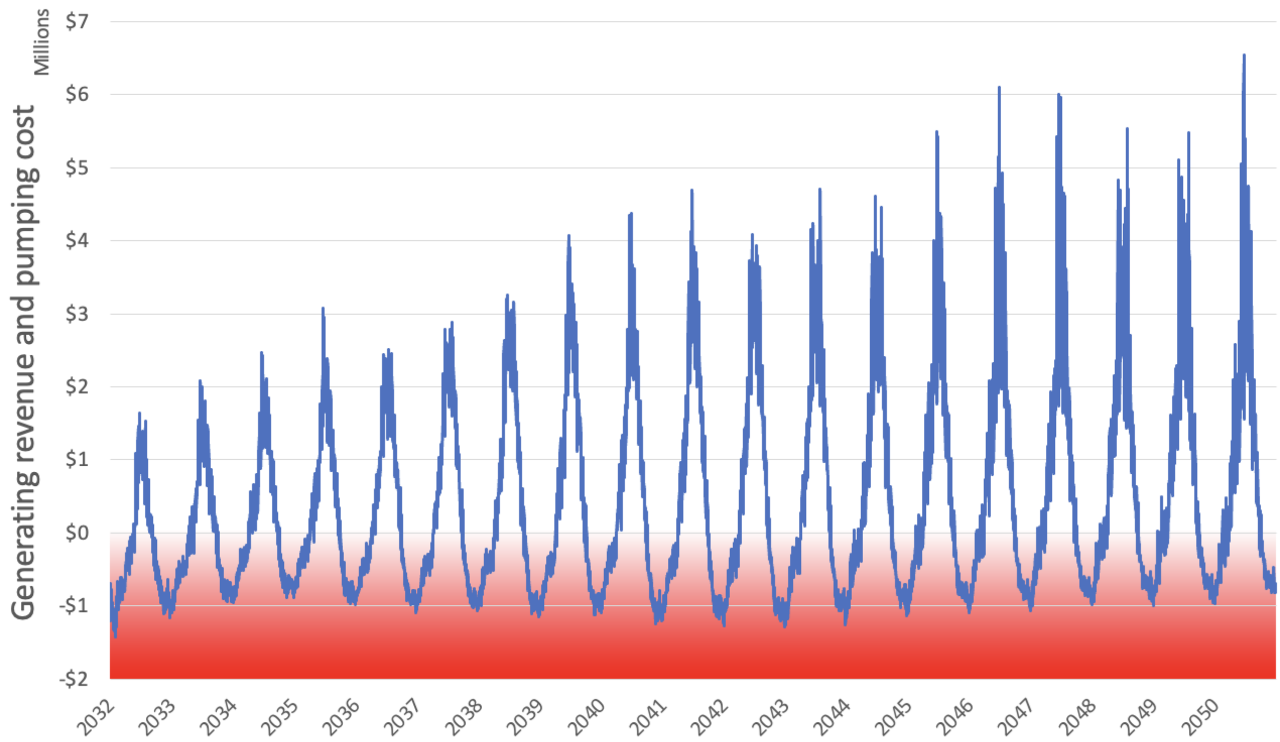


Figure 20: Daily generation revenue (white) and pumping costs (red) for Onslow

During the first two to three years when Onslow is being filled based on water values, net annual revenue will be negative as it spends more money on pumping costs than earning revenue from generating electricity. Figure 8 gives daily net revenues for Onslow between now and 2050 ranked from highest daily net revenue to lowest. Negative values represent days when Onslow is spending more on pumping costs than it does earning revenue from generating electricity.

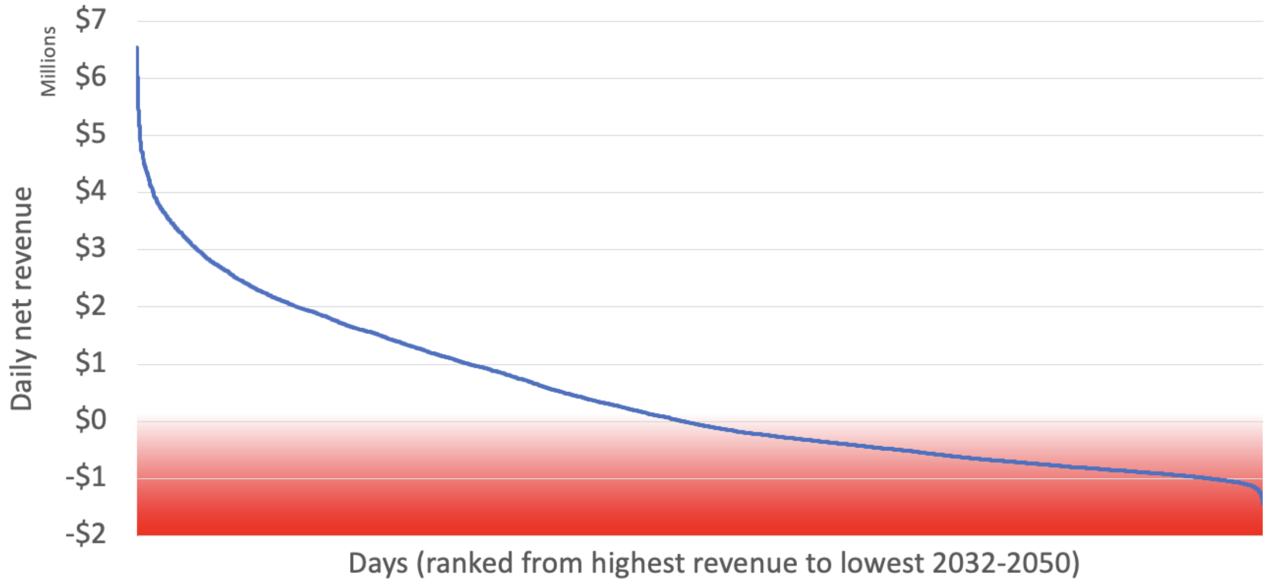


Figure 21: Daily net revenue for Onslow ranked from highest to lowest from 2032-2050 (Christchurch)

A similar analysis can be done to understand what months of the year Onslow will generate electricity or pump. Across the modelling period, monthly revenue peaks in July with an average monthly revenue of $83 million. It bottoms out in December with an average monthly pumping cost of $28 million. On average, Onslow generates positive revenue in the months of April, May, June, July, August and September. On the other hand, it has higher pumping costs in the months of Oct, Nov, Dec, Jan, Feb and Mar. Over the entire year, however, Onslow has a net positive revenue increasing from average annual revenue of $150 million in 2040 to $280 million in 2050 (assuming nodal prices are taken from Christchurch). Figure 22 below shows how monthly revenues and costs will change for Onslow over a typical year.

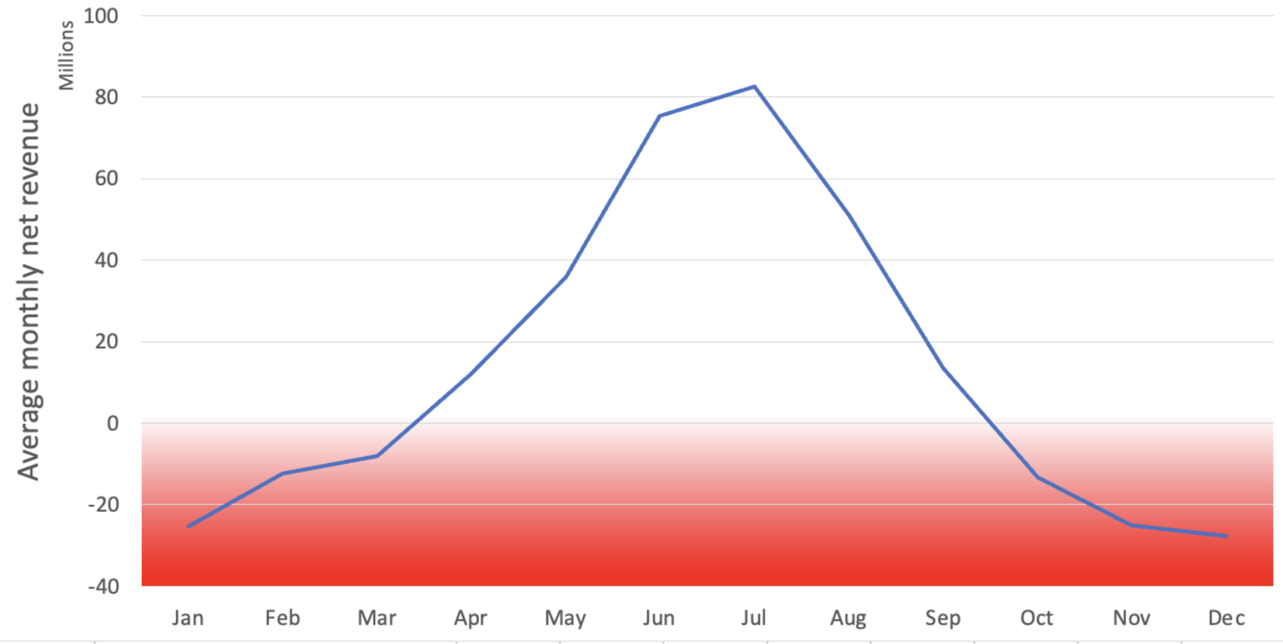


Figure 22: Average monthly revenue (Christchurch node – ISL2) ($Million)

When pumping costs are deducted from the sales revenue we are left with net revenue. Wholesale prices vary by location as per nodal electricity pricing across the national grid. As part of this analysis we explore prices at three different grid nodes, namely, Roxborough (ROX), Christchurch (ISL2) and Auckland (OTA2). Roxborough is the closest node to Onslow so this node would represent the most likely electricity prices for Onslow absent any future grid upgrades. However, given it is highly likely that grid infrastructure will be upgraded to improve the flow of electricity supply from Onslow, it is important to understand how revenues will potentially vary as grid constraints are removed. Annual net revenues are therefore reported for three nodes on the network and can be thought of as the lower and upper bounds of revenue potential under different levels of network upgrade. For later analysis we use the Christchurch node to estimate the revenue potential for Onslow given that the electricity network will likely be upgraded to some extent to realise the economic benefits provided by Onslow.

Across all nodes, net revenue is negative in the first two years while the dam is being filled. Revenues then increase year on year increasing to between $200-400 million per year in 2050. As expected, the lowest revenue potential is from wholesale prices occurring at the node in Roxborough and the highest revenue potential occurs for wholesale prices in Auckland.

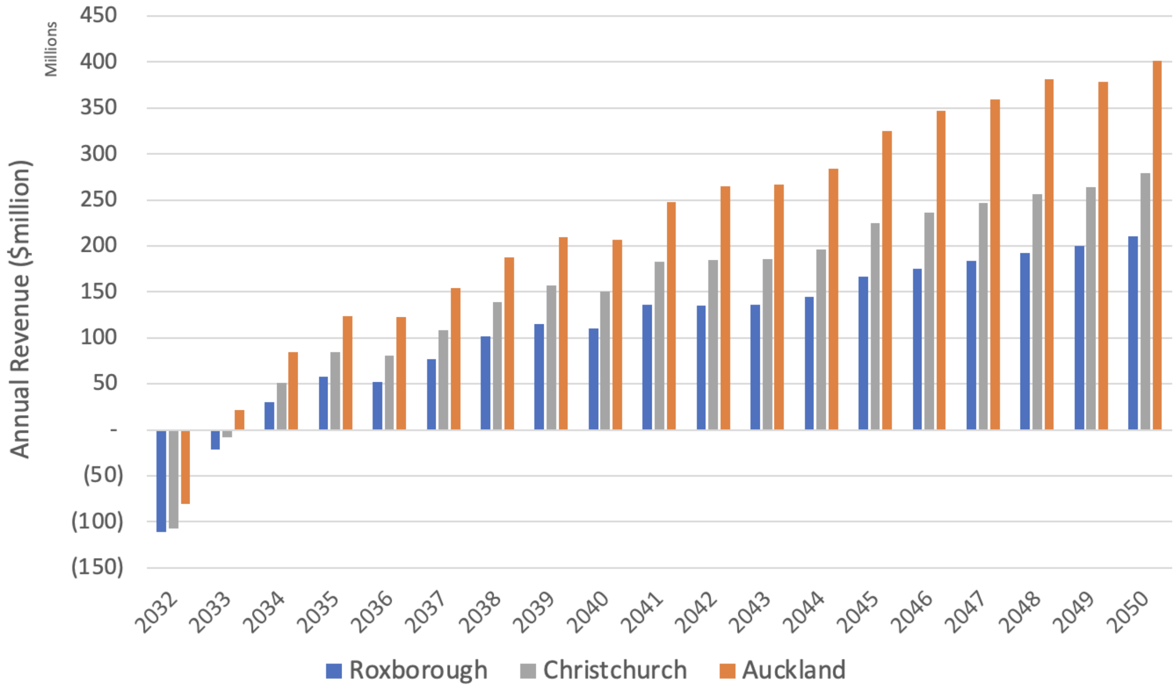


Figure 23: Annual average revenue for Onslow by network node

From this revenue we also must deduct other operation and maintenance costs for Onslow. Based on a construction cost of $15 billion we assume operation and maintenance costs of $42 million per year over the full life of the asset[24]. By 2050 net revenue for the Christchurch node (ISL2) would therefore reduce from $280 to $238 million[25] depending on the extent of grid upgrades. If net revenues from Onslow beyond 2050 remain relatively stable at 2050 levels, Onslow would generate a total undiscounted net positive revenue of between $13-29 billion[26] over its estimated 100-year life – the range representing the extent of grid upgrades that would need to occur to maximise revenue potential[27].

The annual volatility in potential revenue is also critical. Using wholesale nodal prices at Christchurch as an example, the expected range in net annual revenue is shown in Figure 24. In this plot the darker colours represent more certainty over annual net revenues while the lighter colours represent less certainty. This chart clearly shows that most of the time Onslow returns a positive revenue, potentially reaching as high as $600m per year by 2050, but occasionally may also return negative revenues, with lower likilihoods. Throughout this report mean average values are reported when referring to revenue.

[24] IRENA estimate that the O&M costs for a typical large hydro project are around $45 per kW per year. For Onslow this equates to $45 x 1,000,000 kW = $45 million per year. See https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2012/RE_Technologies_Cost_Analysis-HYDROPOWER.pdf page 25.

[25] This considers pumping costs as well as operation and maintenance costs assuming nodal prices at Christchurch.

[26] Constant 2022 prices in NZD with the range representing worst and best cases for removing network constraints.

[27] The pumped hydro scheme is assumed to operate for 100 years.

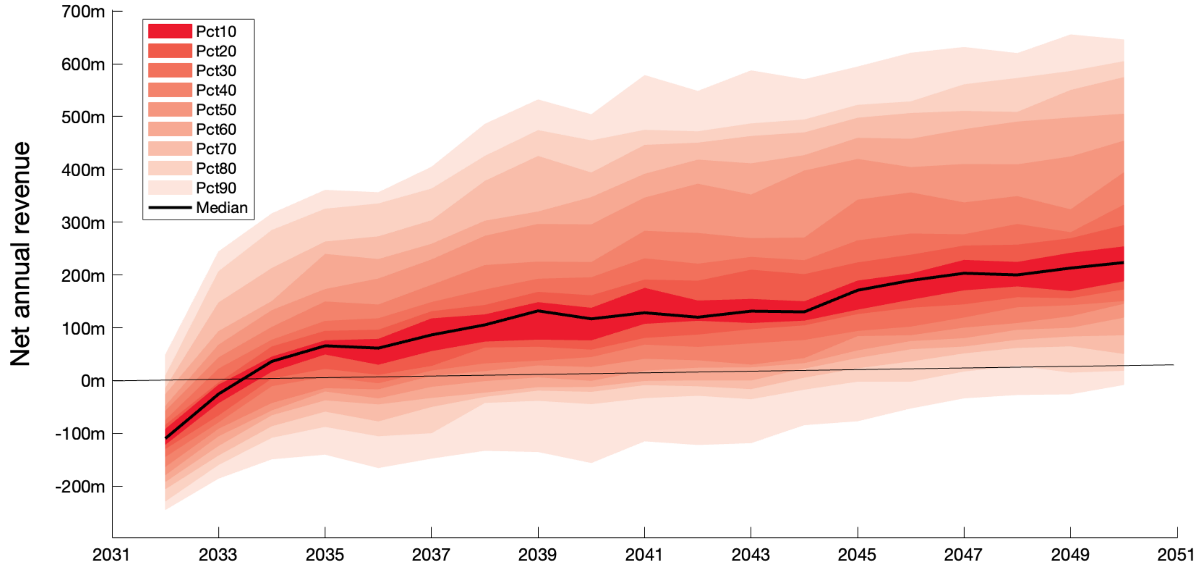


Figure 24: Onslow annual net revenue variability (Christchurch)

Peak demand

Peak demand was estimated for each pathway as the maximum annual aggregate demand across the entire electricity network. Peak demand drives network infrastructure investment. The location of demand relative to generation capacity is therefore important as this is what determines where upgrades to network infrastructure will be required. This analysis did not assess the location of grid constraints or the optimisation of locating new generation capacity. Aggregate peak demand across the entire network is therefore used as a proxy for the extent of grid upgrades that would need to occur in each pathway.

Figure 25 shows how aggregate peak demand on the network will vary over time for each of the different pathways. The pathway with the lowest aggregate peak demand is Pathway 1: Tiwai Point closes with an estimated peak demand of 8.3 GW in 2050. This is because the Tiwai Point aluminium smelter requires around 572 MW of electricity, so when Tiwai Point is shut down aggregate demand on the network is reduced below the base case pathway.

Pathway 0: Base case and Pathway 3: Onslow are shown to have the same aggregate peak demand on the network increasing to 8.9 GW by 2050. This suggests that despite Onslow being an additional load on the network, this load occurs during non-peak periods. Similarly, when Onslow is generating it only generates to meet existing demand requirements. It therefore makes sense that the Onslow does not contribute to peak demand across the network, but may alleviate the requirement for upgrading other parts of the electricity network if electricity flows from Onslow north were prioritised.

Both hydrogen pathways were shown to cause the highest aggregate peak electricity demand on the network, owing to the additional renewable electricity supply that is required for producing hydrogen which adds to the peak capacity of the network. Both hydrogen pathways were shown to have an annual peak demand of around 9.5 GW by the year 2050, a full 600 MW higher than the base case or Onslow pathway.

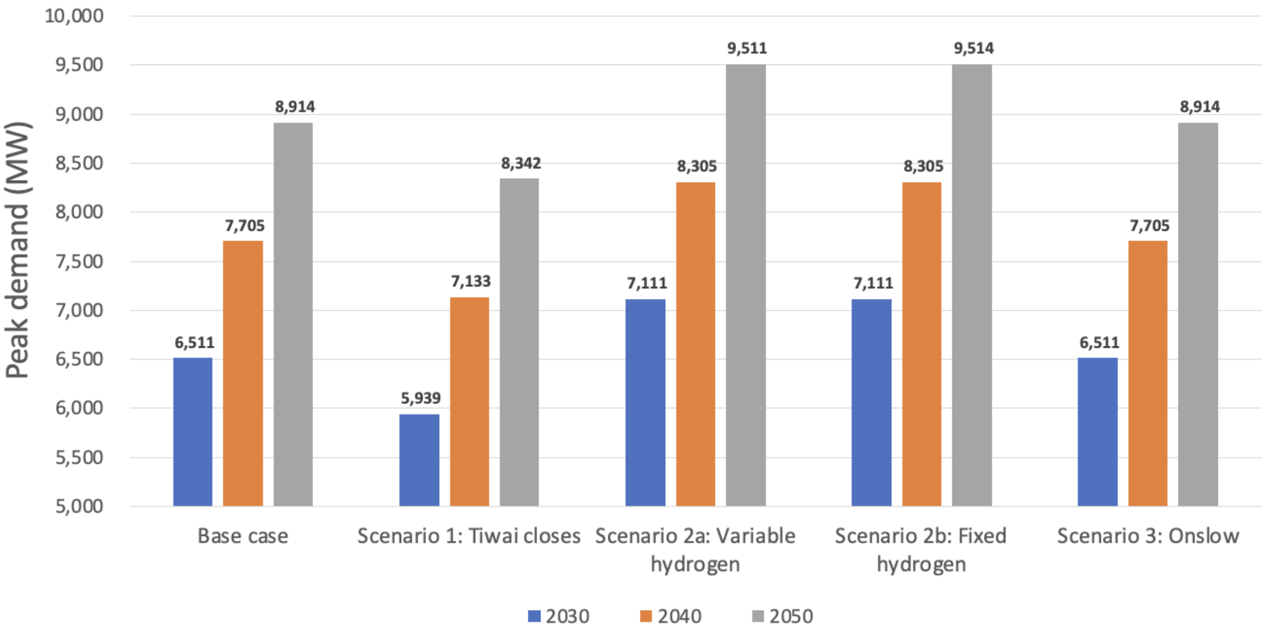


Figure 25: Peak electricity demand across entire network

Dry year risk

One of the main arguments for building Onslow or the Southern Green Hydrogen production facility is to mitigate seasonal and dry year risk. Dry year risk has been identified as an emerging risk to the stability and security of the electricity system as flexible fossil fuel generation is taken offline and replaced with variable and intermittent renewables. Insufficient generation capacity could result in rolling blackouts and much higher electricity prices for consumers. At present, gas and coal fired generation are capable of meeting inter-seasonal shortfalls in the supply of electricity across the country, however, as fossil fuel generators are decommissioned (in line with net zero 2050 emissions targets) it will be necessary to meet electricity shortfalls from other low carbon resources.

Onslow and SGH would both operate differently to meet inter-annual and seasonal shortfalls. An SGH plant is expected to meet interannual dry-year shortfalls by curtailing demand for the production of hydrogen. Thus, in an extended dry period the operation of a 500MW hydrogen production facility would be scaled back so that electricity normally consumed in the SGH facility would flow into the grid. One disadvantage of this strategy is that electricity supply would need to be available when the SGH facility curtailed its demand. With a growing share of renewables coming online there is no guarantee that electricity generation would be available when required, especially if it was a still cloudy day, so there would still need to be sufficient flexible generation capacity to meet the demand shortfall across the grid. This implies gas generation would likely continue to play an important role even if a major hydrogen production facility such as Southern Green Hydrogen were to be built.

There are also financial costs to curtailing demand from a hydrogen production facility that would need to be recovered. Compensation to the hydrogen production facility for curtailing their output would be required and this would ultimately get passed onto consumers. Because the curtailing of demand would coincide with a time of high electricity prices, an upfront 'swaption' contract would likely be needed to guarantee the curtailment in production from the hydrogen facility. The value of electricity in such a contract would be high to reflect the scarcity value of electricity at a time it was needed most, it would also need to go some way to compensating the hydrogen plant for the lost revenue it would have otherwise received from producing hydrogen[28].

Energy Link estimate the maximum difference between Pathway 2a and 2b is $409/MWh, representing an estimate for the value of flexible demand[29]. Using this estimate, a variable shortfall of 150 MW over three months would cost $132 million. Switching SGH off completely for one month would add a further $177 million for a total of $309 million. Meridians own modelling showed that an SGH plant could secure up to $80 million in revenue every year by offering demand response to the grid[30]. This would be in addition to the amount SGH could be paid for turning off in a dry period. All things considered, an annual 'swaption' contract to the value of $200 million was therefore assumed to provide the required demand response and the possibility to switch off hydrogen capacity for a duration of one month in a dry year. If a dry period lasted for several months, the cost would be proportionally much higher, this pathway was not considered but could theoretically cost well over $500 million if the hydrogen production facility was shut down for several months. For the purposes of this modelling a swaption contract of $200 million was assumed which equates to an additional 0.30 to 0.45 cents per kWh per year on consumer electricity bills on average.

Onslow would meet dry year demand in a different way. Onslow would store potential energy and then release that energy when it was required during a dry year. Storing that energy in the first place requires water to be pumped which has a cost. Therefore, pumping would only occur when prices were sufficiently low and generation would occur when prices were sufficiently high.

One way to assess the extent to which each pathway can meet future dry year risk is to look at 'supply of last resort' (SLR). Within the Energy Link model, SLR is the quantity of generation shortfall that remains unmet, signalling a period when demand exceeds supply. This difference must be met using SLR – it is therefore the most expensive form of electricity generation or demand reduction available. The Electricity Authority and previous energy link publications have estimated the cost of using 'supply of last resort' as being around ~ $10,000/MWh[31]. Figure 26 shows the supply of last resort in GWh for each pathway in this analysis. The Onslow pathway has the smallest requirements for SLR. The Onslow pathway requires just 20 GWh of SLR in 2050 compared with 54 and 35 GWh in Pathways 2a and 2b for the two hydrogen pathways respectively. Assuming a cost of $10,000/MWh for the use of SLR, Figure 27 shows the costs when compared to the base case for each of the different pathways. Pathway 1 (Tiwai Point closing) and Pathway 3 (Onslow) have lower costs than the base case (e.g. a saving compared to the base case) while both hydrogen pathways cost more than the base case in 2040 and 2050. The costs associated with supply of last resort were not included in the price pathways or the financial cost benefit analysis presented later in this report. These costs are provided here for information purposes only. When undertaking a more comprehensive social cost-benefit analysis it is recommended that the costs associated with security of supply and electricity outages needs to be considered when comparing pathways given the potential magnitude of these costs.

[28] An analysis of the potential value of hydrogen production was outside the scope of this research.

[29] The wholesale prices difference between Scenario 2a and 2b was estimated to give an estimate for the value of flexible demand provided by operating the hydrogen plant in flexible mode. This was then used to determine the value of a contract between SGH and gentailers for the SGH facility to curtail their demand.

[30] Meridian. Climate related disclosure. 2022. (page 8) https://www.meridianenergy.co.nz/public/Sustainability/2022/FY22-Meridian-Climate-related-disclosure.pdf,

[31] https://www.energylink.co.nz/news/blog/price-formation-100-renewable-electricity

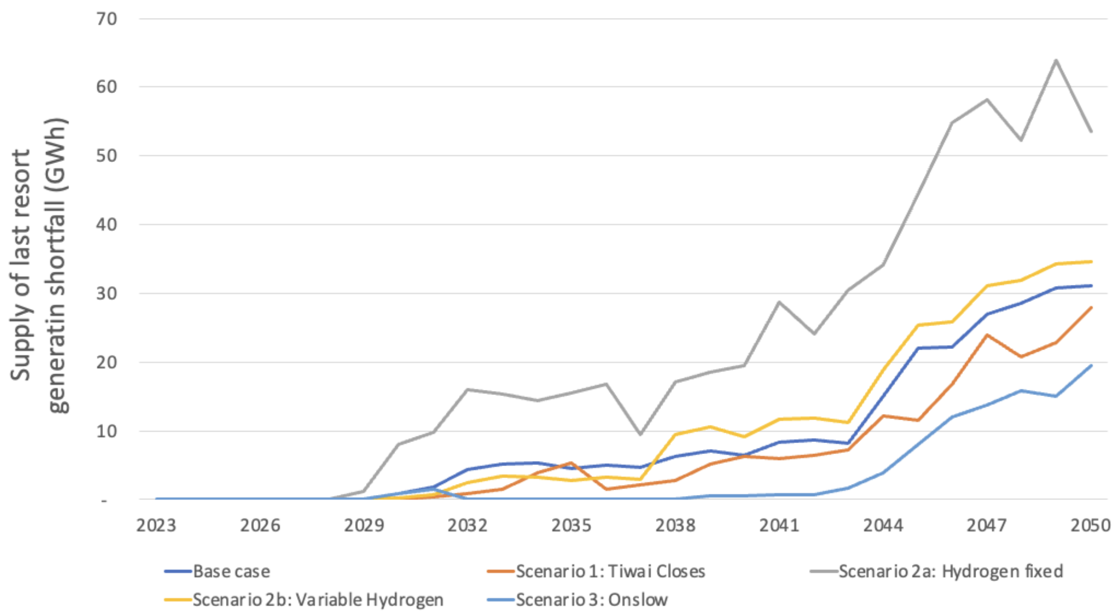


Figure 26: Supply of last resort (dry year risk) (GWh)

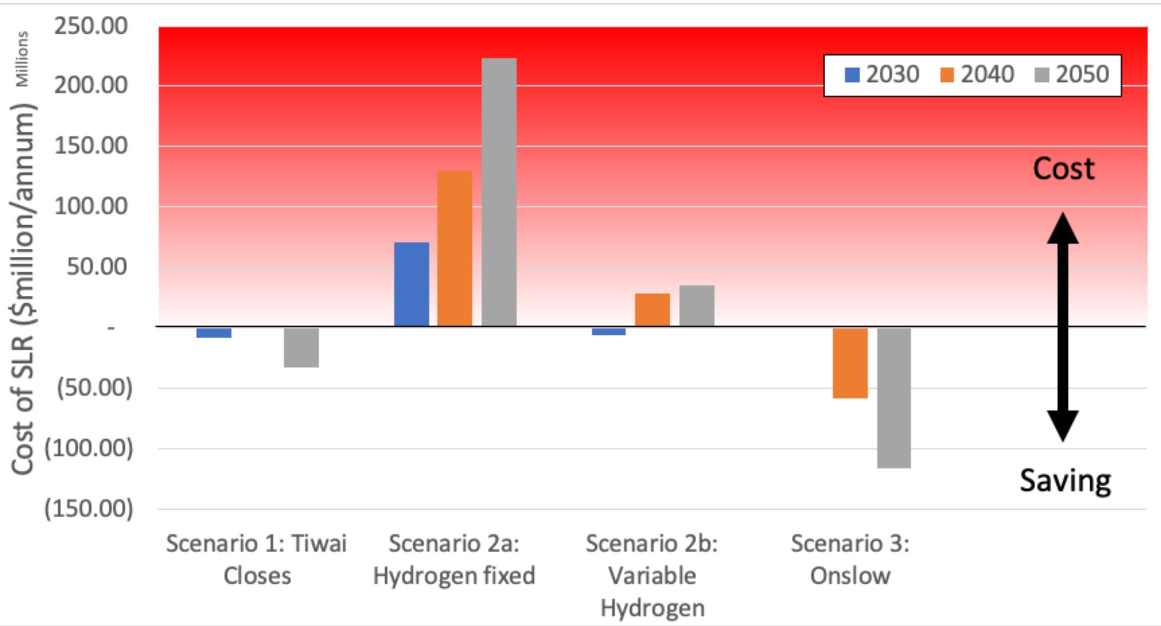


Figure 27: Supply of last resort cost compared to base case @ $10,000 /MWh

Market volatility

Volatility in wholesale spot prices is an important driver of system wide costs, increasing price risks and contributing to uncertainty about future investment. Volatility in spot prices also requires increased regulatory oversight and closer management of the grid to ensure the demand and supply of electricity is kept in balance (increased regulatory costs have not been allowed for in this analysis). Volatility also implies that larger swings in generation and demand across different nodes on the network an increased likelihood of parts of the grid operating much closer to its capacity limits and therefore contributing to increased wear and tear on physical infrastructure with associated risks of trips and failures. This results in higher operational and maintenance costs across the network (also not allowed for in this modelling). Volatile prices also tend to favour investment in fossil-based flexible generation which are carbon intensive (e.g. gas-peakers). Flexible generation is charged at a premium when compared to non-flexible resources. An assessment of market spot price volatility was therefore undertaken across each of the pathways.

Figure 28 shows annual spot price volatility for each of the different pathways. In finance, volatility is a statistical measure of dispersion around its mean over a certain time period[32]. It is typically calculated as the standard deviation divided by the square root of the number of periods in the analysis. In order to calculate volatility in market spot prices, the average wholesale spot price was calculated for all 91 model runs for each day between now and 2050. The standard deviation was then calculated on these average prices for each year which was then divided by the square root of the number of time-steps in each period (e.g. 365 days in the year). As expected, Onslow reduces seasonal market volatility by a considerable margin, and significantly more than all other pathways assessed.

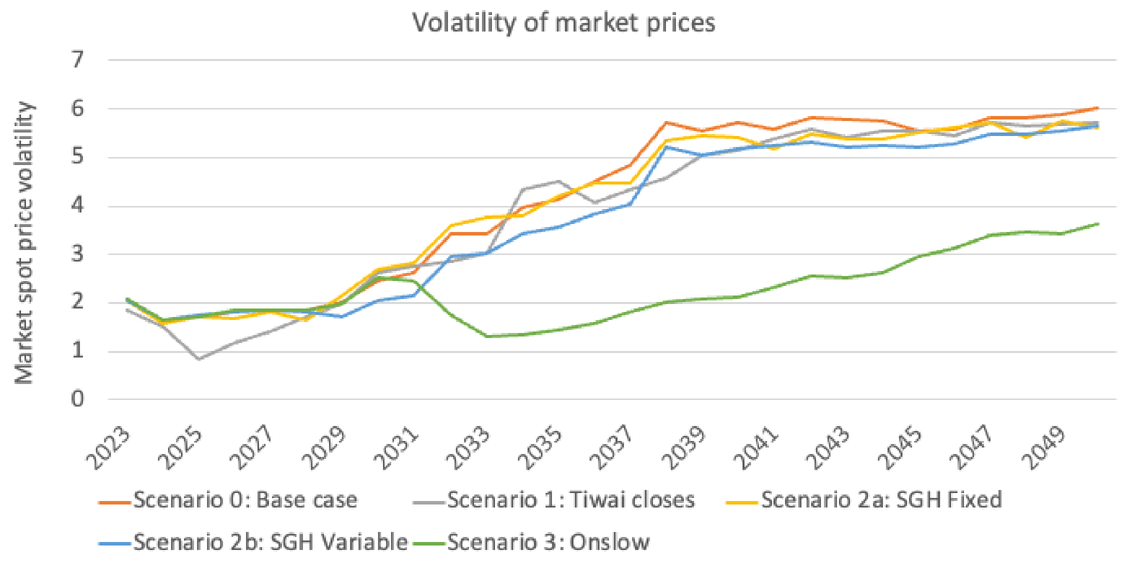


Figure 28: Intra-annual spot price volatility

The flattening of seasonal price volatility can also be seen in Figure 29 which shows how Onslow flattens the peaks and troughs for the years 2040 to 2041 and 2049 to 2050. In 2040, Onslow lowers the peak seasonal price by as much as \$100 to \$150/MWh. Even by 2050 Onslow still reduces peak seasonal prices by between \$50 and \$75/MWh on average. It is interesting to note that as well as suppressing high prices, Onslow also raises the lowest prices, thus providing an effective floor price in the market which is advantageous for intermittent renewable generation giving certainty over future minimum prices thus bringing forward investment in new renewable electricity. The spill-over effect which reduces the cost of capital for renewable electricity investment has not been allowed for as part of this economic analysis, but should be considered as part of future social cost benefit assessments.

32 $\overline{\sigma_x} = \frac{\sigma}{\sqrt{T}}$, where $\overline{\sigma_x}$ is the measure of annual volatility, σ is the standard deviation of the period in question and T is the number of time-steps in the period (e.g. 365 for daily measurements over a year).

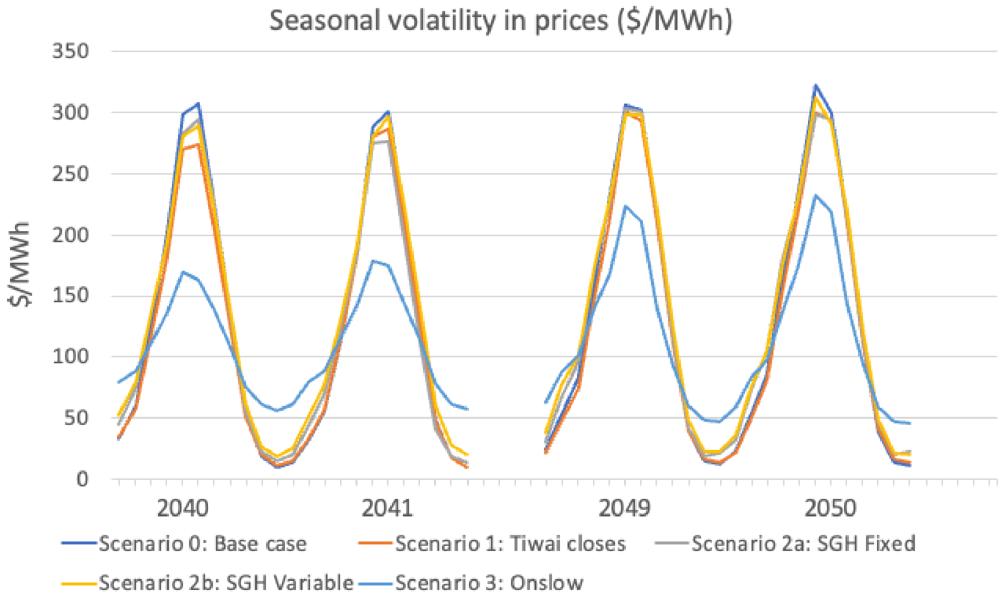


Figure 29: Average monthly price volatility for years 2039,2040,2049,2050

Emissions

Understanding how emissions evolve under each pathway is important for ensuring New Zealand is on track for meeting its net zero 2050 target. Energy Link's gas and coal price forecasts were used in all five modelled pathways. The CCC's real carbon prices[33] were used for all pathways based on their "Tiwai Point stays with certainty" pathway after adjusting for inflation to the present day. These projections would see carbon prices hitting $250 per tonne by 2050.

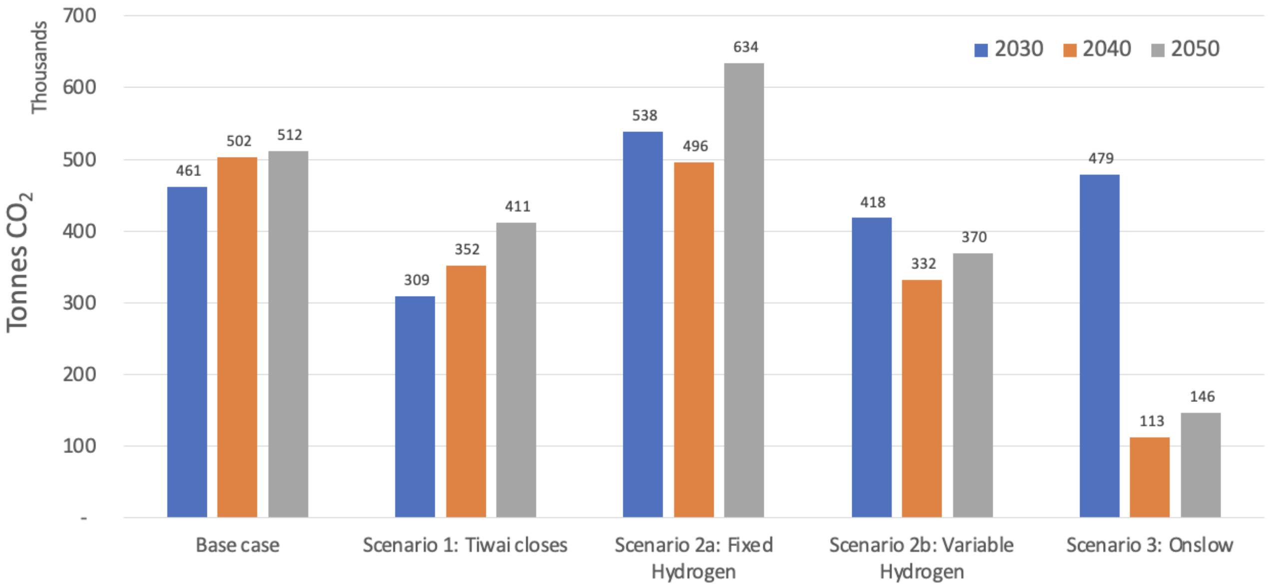
All pathways were run based on market conditions and no assumptions were made about the date for when different fossil fuel generation plants would be retired. This allows the evolution of carbon emissions based on the natural evolution of CO_2 prices and market conditions. Table 2 shows the estimated date at which major thermal plant are retired. It is clear from this table that there is little difference between the pathways for when large thermal plant retires (except for Pathway 1: Tiwai Point closes). The retirement of fossil-fuel plant is likely conservative as the life of some plant could be extended by several years through upgrades and improved maintenance and switching to green fuels (e.g. Huntly fuelled by biobased pellets). The ability to extend the life of existing plant is an important stopgap solution if Onslow were to proceed, providing additional generation capacity while Onslow was being built and filled.

[33] Draft Advice for Consultation. 2021. Climate Change Commission. https://haveyoursay.climatecommission.govt.nz/comms-and-engagement/future-climate-action-for-aotearoa/supporting_documents/CCCADVICETOGOVT31JAN2021pdf.pdf

Table 2: Retirement of fossil-fuelled thermal plant[34]

Plant	Status	Base Case	1: Tiwai Closes	2a: SGH Baseload	2a: SGH Dispatched	3: Onslow
TCC CCGT	Closure	Oct-23	Oct-23	Oct-23	Oct-23	Oct-23
Huntly 1st Rankine Unit	Closure	Oct-27	Sep-24	Oct-27	Oct-27	Oct-27
Huntly 2nd Rankine Unit	Closure	Jan-30	Sep-24	Jan-30	Jan-30	Jan-30
e3p (Unit 5) CCGT	Winter Mode	Oct-28	Apr-25	Oct-28	Oct-28	Oct-28
	Dry Year Mode	Oct-31	Apr-30	Oct-31	Oct-31	Oct-31
	Closure	Oct-37	Jan-34	Oct-37	Oct-37	Oct-37

Given Onslow is a source of flexible generation it can therefore support the grid during periods of intermittent (non-seasonal) high demand. In addition, because Onslow tends to suppress electricity prices during peak periods, it also reduces the profitability of other carbon intensive generators that tend to operate during these peak periods, drying up a lucrative revenue stream for carbon intensive assets. Figure 30 shows the annual emissions for 2030, 2040 and 2050 across each of the five pathways. Onslow is shown to have the largest drop in emissions coming from thermal generation across all pathways. In 2030 Onslow is not yet operational so there is no difference in total emissions compared to the base case. However, by 2040 the emissions from thermal generation in the Onslow pathway drop by more than 75% compared to the base case. Pathway 1: Tiwai Point closes and Pathway 2b: variable hydrogen both produce less emissions than the base case. Pathway 2a: Fixed hydrogen ends up with higher emissions as new flexible demand must be built to meet peak demand. It is important to note that emissions associated with the construction of Onslow, which include the curing of concrete or emissions produced during the construction phase of a hydrogen production facility have not been included as part of this analysis. The annual emissions from Onslow (including from the construction of Onslow) would be equivalent to around 50,000 tCO_2 per year or around 0.06% of New Zealand's annual total emissions[35].



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[34] Sise, G. Energy Link final report, 2022.

[35] According to the International Hydropower Association, hydroelectricity dams emit around 20 g CO_2/kWh. Assuming Onslow generates an average of 2,500 GWh per year, this amounts to 50,000 tCO_2 per year.

Figure 30: Annual emissions from thermal generation (excluding geothermal and co-generation)[36] (tCO_2)

Electricity prices

Residential electricity prices are made up of several price components according to the following formula:

Residential price = distribution + transmission + wholesale electricity + other (non-energy retail costs)

The distribution and transmission pricing components cover the costs of distribution and transmission electricity infrastructure. Transmission and distribution costs were taken from MBIE's quarterly series of domestic electricity prices (QSDEP). These values were adjusted for known parameters such as the maximum regulated rate at which lines company revenue can increase and changes to the distribution and transmission charges that were expected with the new Transmission Pricing Methodology (TPM) introduced in April 2023. The wholesale electricity component is the market price paid for the generation of electricity on the spot market and varies by grid node across the network. Other (non-energy costs) are the costs associated with supplying electricity such as retail costs and administration.

Estimating residential electricity prices requires forecasting each of the price components in the formula above. Wholesale electricity prices can be forecast using the Energy Link's market model, but the other price components must be estimated using a different approach. A method was therefore developed by Energy Link to use Internal Transfer Prices (ITPs). Under Part 13 of the Code[37], gentailers must disclose their ITPs and retail gross margins to the Electricity Authority. Under this system, transfer prices are defined as the average load weighted retail ITP which is calculated by dividing the notional cost of electricity by the total amount of electricity (MWh) sold to customers. For further information on the use of internal transfer pricing and how it was used to estimate residential electricity prices please see the technical documentation provided by Energy Link[38]. Other key assumptions were taken from Energy Link's July 2022 Price Path including the price of natural gas and coal use in fossil fuelled generation, future carbon prices and the estimated costs of building new generation based on up-to-date estimates of the Levelised Cost of Energy (LCOE).

Figure 31 breaks down the different electricity price components for Auckland and Christchurch. While the total residential electricity price is similar for both cities (Auckland: 29.3 c/kWh vs Christchurch: 28.7 c/kWh) the components that make up these prices vary. Transmission and distribution costs are higher for Auckland than Christchurch while wholesale and non-energy costs are lower for Auckland than Christchurch, thus making up for these differences.

[36] Cogeneration contributes a significant amount of emissions and are excluded from this analysis. Geothermal plant also contribute to emissions and are also excluded from these emissions statistics.

[37] Clause 13.256 and 13.266

[38] Sise, G. Energy Link final report, 2022.

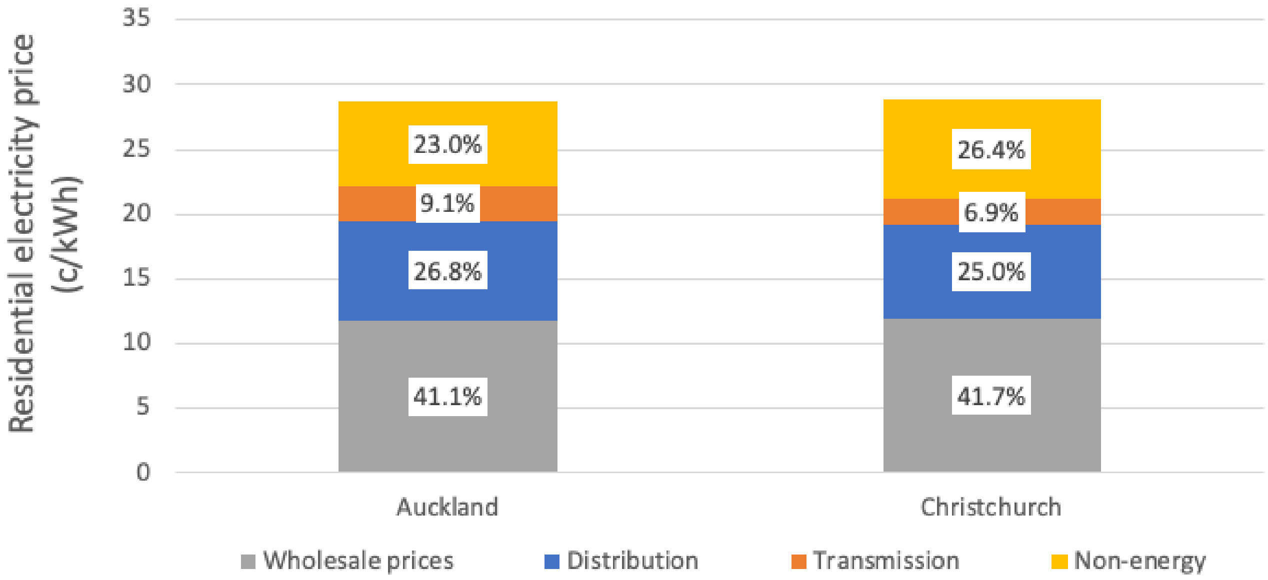

Figure 31: Residential electricity price components for Auckland and Christchurch in 2025

Table 3 gives the residential electricity prices for Auckland and Christchurch in 2025. The reason for the difference in non-energy related costs between Auckland and Christchurch is likely because the Auckland market is the most competitive market in the country, leading to lower margins for retailers. There may also be some economies of scale available to retailers in Auckland who are able to service a larger market more efficiently.

Table 3: Residential electricity price components in 2022 (cents/kWh)

	Distribution	*Transmission*	*Wholesale spot price*	*Non-energy*	*Total price*
Auckland	8.49	2.85	12.76	5.15	**29.3**
Christchurch	7.52	2.71	12.02	6.47	**28.7**

When considering just the wholesale component of electricity prices, Figure 32 shows that Onslow maintains the lowest wholesale electricity price when compared against the other pathways. This situation lasts for the entire period that Onslow is considered fully operational from 2034 onwards. The reason for the spike in wholesale prices for the Onslow pathway between 2032 and 2033 is because Onslow places extra demand on the electricity system while it is filling from empty, thus driving up prices. While the same issue arises after a dry year, the historical inflows of the Energy Link model already take into account dry years and are averaged out, so the price spike is only an issue in the first few years while the dam is filling[39]. To minimise the effect of this price spike while the dam is filling, it may be necessary to allow Onslow to fill over a longer period. This could be achieved by implementing a ceiling on the wholesale price at which Onslow was allowed to pump. This would ensure that Onslow was only filling at the cheapest possible prices and would prevent prices spiking across the network. Because this policy would extend the overall time that Onslow took to fill, it would need to consider the risks of Onslow not having sufficient capacity to meet electricity demand

[39] Further analysis is recommended to understand the risk of multiple dry years.

during a potential dry year if other flexible capacity in the network was unavailable at that time. It is assumed this regime would only occur while Onslow was filling.

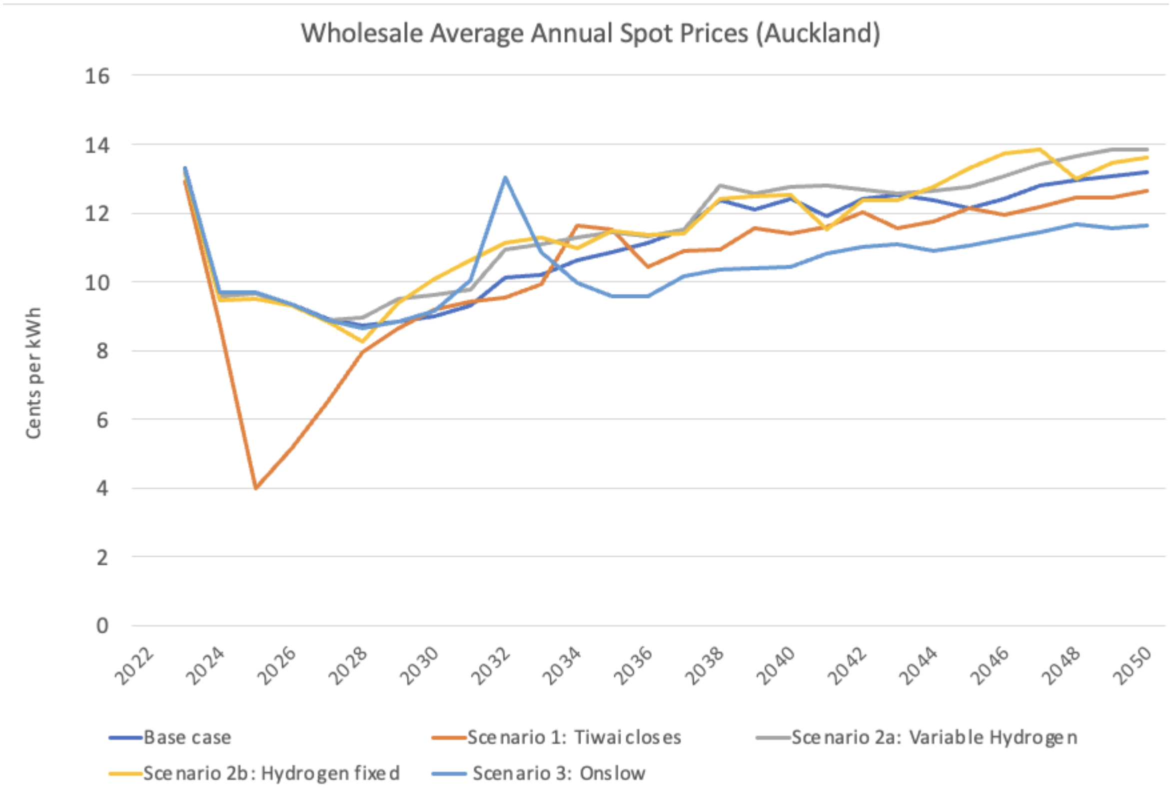

Figure 32: Average annual wholesale electricity prices for the five pathways for Auckland.

Given the expected operating revenue will likely be insufficient to cover the cost of capital, the residual costs are assumed to be recovered by a levy charged to final electricity consumers. Using the capital cost recovery method which is based on the weighted cost of capital (WACC)[40], an annualised recovery cost was estimated to pay for the capex costs associated with constructing Onslow. For example, assuming Onslow cost $15 billion with an asset life of 100 years and a real WACC of 5%, the annualised cost of capital is estimated at approximately $760 million per year. This cost is first reduced by net annual operating revenue with remaining costs paid by an annual levy that is charged for each kWh of electricity consumed across the entire network. In order to estimate the levy on consumers, the annual operating revenue is first deducted from the annual cost of capital. The residual cost of capital is then divided by the total amount of kWh consumed across the network. As revenues from Onslow increase over time, the expected electricity recovery charge on consumer bills declines. For the worst-case scenario, assuming a 5% WACC and a 50-year asset life, the annual levy is shown to drop from around 1.6 cents per kWh in 2032 to around 1.23 cents per kWh in 2050. Alternatively, if a real WACC of 2% is assumed over a 100 year period, the charge on consumers reduces from 0.63 c per kWh in 2034 to 0.11 cents per kWh in 2050. This is shown in Figure 33 across each of the four sensitivity scenarios. This levy can best be considered as an insurance cost charged to consumers for ensuring the security of electricity supply across the network.

[40] Given Onslow is assumed to be completely funded by debt, the WACC reduces to the following cost recovery calculation: $CRF = \frac{r(1+r)^n}{(1+r)^n-1}$. CRF is the cost recovery factor, r is the real interest rate and T is the period over which costs are recovered.

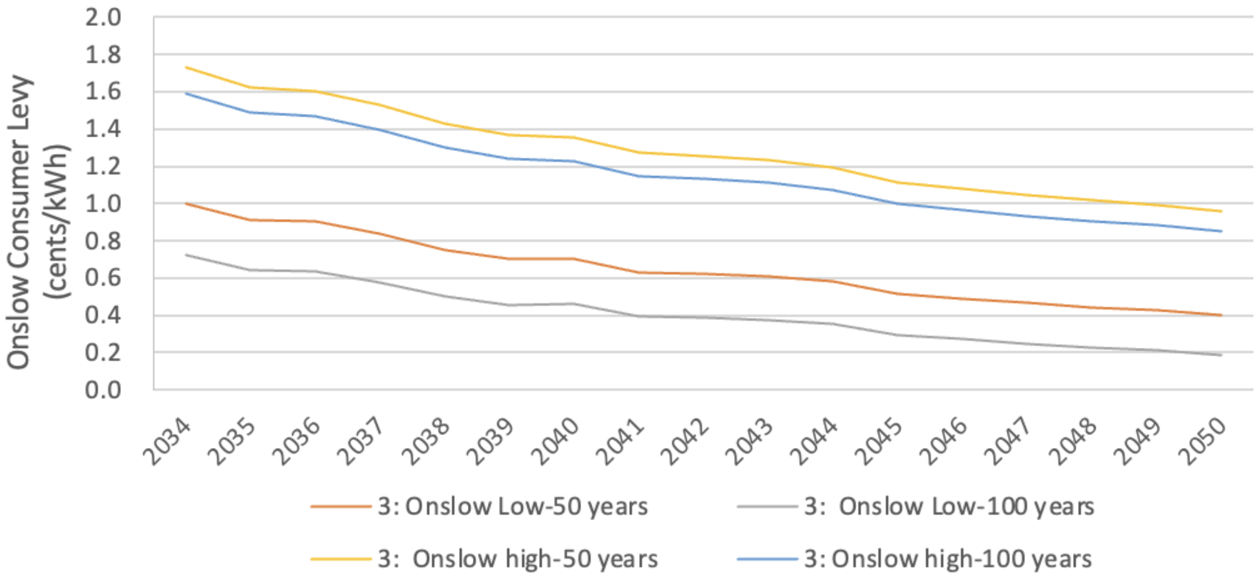

Figure 33: Onslow capital cost recovery levy

Table 4 shows the annual national electricity demand across the different pathways. Table 5 and Table 6 give the expected wholesale electricity prices for Auckland and Christchurch across each of the pathways. Table 7 shows how electricity demand is split between residential, commercial and industrial consumers. It also includes the average electricity price paid by different consumers in 2020.

Table 8 and Table 9 estimate the final expected residential electricity price after all the various costs to consumers have been taken into account including all levies and charges.

Table 4: Annual demand projections (GWh per annum)

Annual Demand (GWh)

	2020	2030	2040	2050
Scenario 0: Base Case	38,365	44,744	54,125	61,748
Scenario 1: Tiwai closes	38,365	44,744	54,125	61,748
Scenario 2a: SGH Fixed	35,335	49,958	59,295	66,884
Scenario 2b: SGH Dispatch	35,909	48,914	58,125	65,794
Scenario 3: Onslow	38,365	44,742	54,233	61,848

Table 5: Auckland wholesale prices (cents/kWh)

Auckland wholesale prices (cents per kWh)

	2020	2030	2040	2050	% Difference with Base Case in 2050
Senario 0: Base case	11.3	11.2	12.4	13.6	
Scenario 1: Tiwai closes	11.3	10.4	11.8	13.0	-1.9%
Scenario 2a: SGH Fixed	11.3	11.5	12.5	14.1	1.4%
Scenario 2b: SGH Variable	11.3	11.3	12.8	14.1	1.7%
Scenario 3a: Onslow	11.3	11.3	11.7	12.4	-3.7%

Table 6: Christchurch wholesale prices (cents/kWh)

Christchurch wholsale prices (cents per kWh)

	2020	2030	2040	2050	% Difference with Base Case in 2050
Senario 0: Base case	11.0	11.8	13.8	15.7	
Scenario 1: Tiwai closes	11.0	10.3	11.9	13.4	-7.3%
Scenario 2a: SGH Fixed	11.0	12.2	14.8	17.7	6.1%
Scenario 2b: SGH Variable	11.0	11.9	13.9	15.7	0.1%
Scenario 3a: Onslow	11.0	12.0	13.1	13.7	-6.3%

In New Zealand, the residential sector consumes 33.4% of total electricity. The remaining demand comes from the industrial, commercial and agricultural sectors[41].

Table 7: Electricity demand and electricity prices by sector in 2022[42]

	Electricity Demand (TWh)	Percentage of demand (%)	Average price (2020) c/kWh
Residential	13.0	34	31.3
Industry	13.5	35	14.6
Commerce	9.4	25	18.5

[41] There is also a small amount of demand allocated to 'other' and 'transport' but these sectors make up less then 2% of overall demand. It is recognised that transport will significantly increase its overall share of electricity over the coming 30 years but for the purposes of this modelling transport is assumed to be incorporated into the modelled sectors.

[42] MBIE. 2022. Energy in New Zealand. https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/energy-in-new-zealand/

Agriculture	2.4	6	22.8
Total	**38.3**	**100**	**-**

Table 8 and Table 9 show the future electricity prices for Auckland and Christchurch for each of the different pathways and sensitivity scenarios. As shown, residential prices in 2030 for Auckland ranged from a low of 28.8 c/kWh for Pathway 1 (Tiwai Point closes) to a high of 30.5 c/kWh for Scenario 2a Variable hydrogen with a WACC of 5%. By 2050 residential prices ranged from 31.4 c/kWh in Pathway 3 Onslow: low-100 years to 33.5 c/kWh in Pathway 2b SGH Variable. Results of this analysis show that residential electricity prices return lower electricity prices by 2050 than the base case in the Tiwai Point scenario and every Onslow scenario for both Auckland and Christchurch (% change shown in red).

In 2050 for Auckland, electricity prices range from an increase in electricity prices of 3.2% in Scenario 2b Variable Hydrogen to a saving of 3.4% in Scenario 3: Onslow low-100 years. In 2050 for Christchurch, electricity prices range from an increase of 6.9% in Scenario 2a: SGH Fixed Hydrogen to a saving of 7.9% in Scenario 1: Tiwai Point closing. Interestingly, the fixed hydrogen scenario has lower price increases in Auckland than the variable scenario, and vice versa for the South Island.

Table 8: Auckland residential electricity prices (cents/kWh)

Auckland residential electricity price (cents per kWh)

	2020	2030	2040	2050	% Difference with Base Case in 2050
Senario 0: Base case	31.3	29.7	31.1	32.5	
Scenario 1: Tiwai closes	31.3	28.8	30.4	31.8	-2.2%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	31.3	30.2	31.4	33.1	1.8%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	31.3	30.4	32.1	33.5	3.1%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	31.3	30.2	31.4	33.1	1.9%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	31.3	30.5	32.1	33.5	3.2%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	31.3	29.9	31.1	31.6	-2.7%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	31.3	29.9	30.8	31.4	-3.4%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	31.3	29.9	31.8	32.3	-0.7%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	31.3	29.9	31.7	32.2	-1.1%

Table 9: Christchurch residential electricity prices (cents/kWh)

Christchurch residential electricity price (cents per kWh)

	2020	2030	2040	2050	% Difference with Base Case in 2050
Senario 0: Base case	30.9	30.0	32.3	34.5	
Scenario 1: Tiwai closes	30.9	28.3	30.1	31.8	-7.9%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	30.9	30.5	33.5	36.9	6.8%
Scenario 2b: Variable hydrogen ($750m, 5% WACC, 30 years)	30.9	30.6	32.9	34.9	1.2%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	30.9	30.6	33.5	36.9	6.9%
Scenario 2b: Variable hydrogen (($750m, 2% WACC, 30 years)	30.9	30.7	32.9	34.9	1.3%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	30.9	30.2	32.3	32.7	-5.3%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	30.9	30.2	32.0	32.4	-6.0%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	30.9	30.2	33.0	33.3	-3.4%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	30.9	30.2	32.9	33.2	-3.8%

Figure 34 and Figure 35 show the change in real residential electricity prices from 2004 to 2050 across all pathways for Auckland and Christchurch. Overall, there are higher electricity savings occurring in the South Island than the North Island.

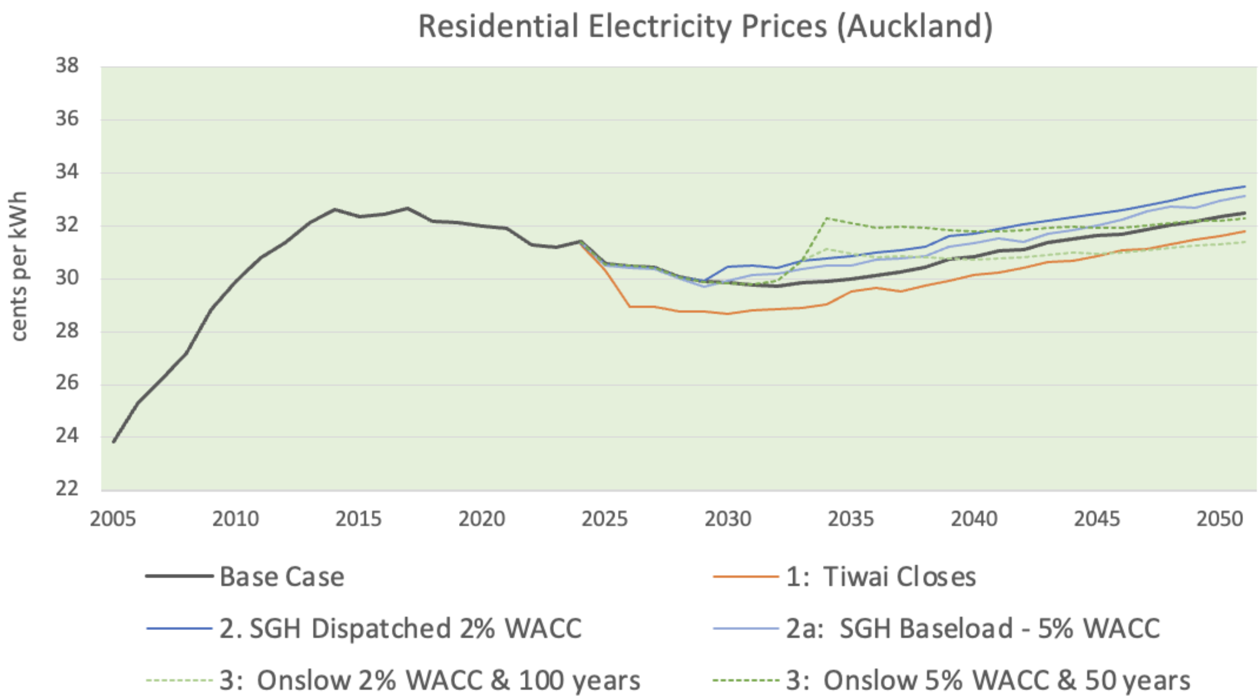

Figure 34: Residential electricity prices by scenario (Auckland)

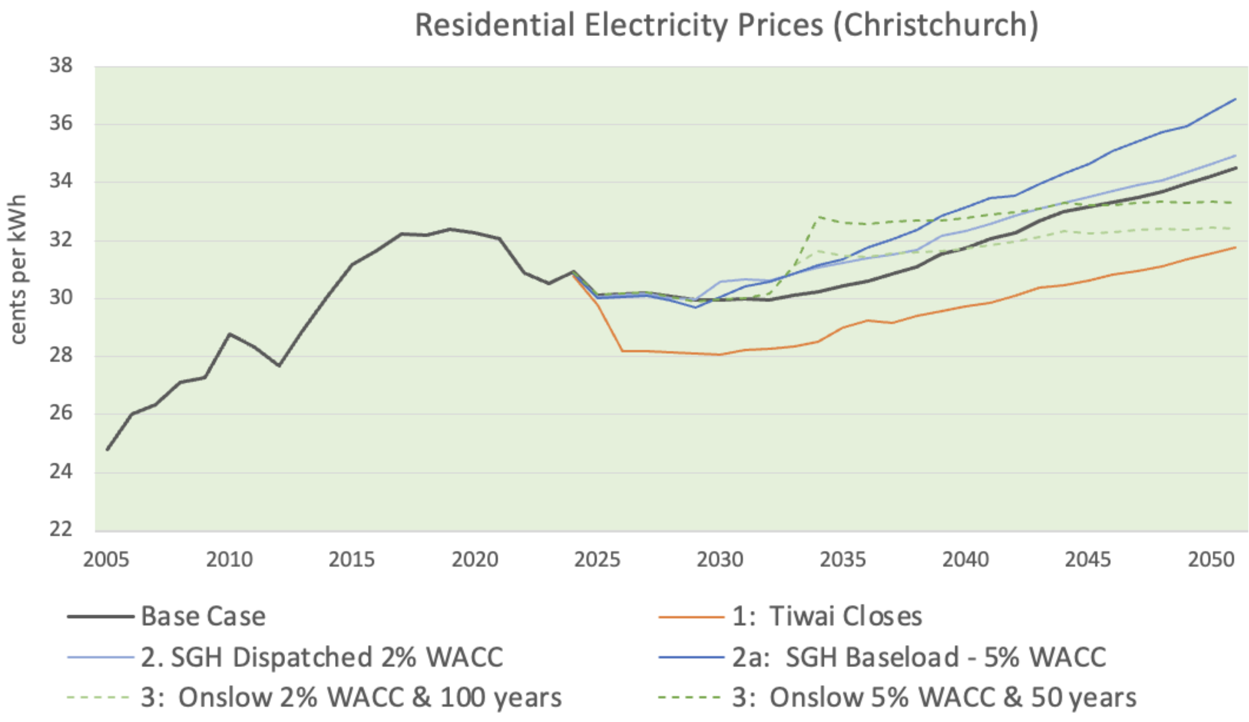

Figure 35: Residential electricity prices by scenario (Christchurch)

Because of differences in final electricity prices across residential, industrial, commercial, and agricultural consumers, it was necessary to calculate the future electricity price for each type of consumer for both Auckland and Christchurch. For this analysis we assume that the same nodal (location based) wholesale electricity price is faced by all residential, industrial, commercial and agricultural consumers. The reason for differences in price across different consumer categories is explained by differences in distribution and transmission charges and other non-energy related costs (e.g. retail margins). To estimate electricity prices for industrial, commercial and agricultural consumers the historical electricity price for each sector was compared with the residential electricity prices over the same historical period. It is then assumed the same price differential between the residential sector and the other sectors will continue into the future. This exercise was completed for both Christchurch (ISL2) and Auckland (OTA2) giving the expected future real electricity price for industrial, commercial and agricultural consumers in each of the modelled scenarios. The results of this analysis are shown in Table 10 and Table 11.

Table 10: Future electricity prices for industrial, commercial and agricultural consumers in Auckland[43]

Auckland industrial, commercial and agricultural electricity prices

Industrial electricity prices (cents per kWh)	2020	2030	2040	2050	% Difference with Base Case in 2050
Senario 0: Base case	14.6	16.1	17.3	18.5	-
Scenario 1: Tiwai closes	14.6	15.3	16.7	17.9	-3.4%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	14.6	16.5	17.5	19.0	2.8%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	14.6	16.7	18.2	19.4	4.9%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	14.6	16.5	17.5	19.0	2.9%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	14.6	16.8	18.2	19.4	5.1%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	14.6	16.2	17.2	17.7	-4.4%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	14.6	16.2	17.0	17.5	-5.5%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	14.6	16.2	17.9	18.3	-1.3%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	14.6	16.2	17.8	18.2	-1.9%
Commercial electricity prices (cents per kWh)					
Senario 0: Base case	18.5	16.8	18.0	19.3	-
Scenario 1: Tiwai closes	18.5	16.1	17.4	18.6	-3.2%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	18.5	17.2	18.3	19.8	2.7%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	18.5	17.5	18.9	20.2	4.7%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	18.5	17.3	18.3	19.8	2.8%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	18.5	17.5	19.0	20.2	4.9%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	18.5	17.0	18.0	18.5	-4.2%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	18.5	17.0	17.8	18.2	-5.3%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	18.5	17.0	18.6	19.0	-1.3%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	18.5	17.0	18.5	18.9	-1.8%
Agricultural electricity prices (cents per kWh)					
Senario 0: Base case	22.8	20.6	21.8	23.0	-
Scenario 1: Tiwai closes	22.8	19.8	21.2	22.4	-2.7%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	22.8	21.0	22.0	23.6	2.3%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	22.8	21.3	22.7	24.0	4.0%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	22.8	21.0	22.1	23.6	2.4%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	22.8	21.3	22.7	24.0	4.1%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	22.8	20.8	21.8	22.2	-3.5%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	22.8	20.8	21.5	22.0	-4.4%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	22.8	20.8	22.4	22.8	-1.1%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	22.8	20.8	22.3	22.7	-1.5%

[43] These prices do not include GST

Table 11: Future electricity prices for industrial, commercial, and agricultural consumers in Christchurch[44]

Christchurch industrial, commercial and agricultural electricity prices

Industrial electricity prices (cents per kWh)	2020	2030	2040	2050	% Difference with Base Case in 2050
Senario 0: Base case	14.6	16.7	18.7	20.6	-
Scenario 1: Tiwai closes	14.6	15.2	16.8	18.3	-11.5%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	14.6	17.2	19.8	22.7	9.9%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	14.6	17.3	19.3	21.0	1.9%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	14.6	17.2	19.8	22.7	10.0%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	14.6	17.3	19.3	21.0	2.0%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	14.6	16.9	18.6	19.0	-8.0%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	14.6	16.9	18.4	18.8	-9.0%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	14.6	16.9	19.3	19.6	-5.2%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	14.6	16.9	19.2	19.4	-5.8%
Commercial electricity prices (cents per kWh)					
Senario 0: Base case	18.5	17.4	19.4	21.4	-
Scenario 1: Tiwai closes	18.5	16.0	17.5	19.0	-11.1%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	18.5	17.9	20.5	23.4	9.6%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	18.5	18.1	20.0	21.8	1.9%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	18.5	18.0	20.6	23.5	9.7%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	18.5	18.1	20.0	21.8	2.0%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	18.5	17.6	19.4	19.7	-7.7%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	18.5	17.6	19.2	19.5	-8.7%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	18.5	17.6	20.0	20.3	-5.1%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	18.5	17.6	19.9	20.2	-5.6%
Agricultural electricity prices (cents per kWh)					
Senario 0: Base case	22.8	21.2	23.2	25.2	-
Scenario 1: Tiwai closes	22.8	19.7	21.3	22.8	-9.4%
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	22.8	21.7	24.3	27.2	8.1%
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	22.8	21.9	23.8	25.6	1.6%
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	22.8	21.8	24.3	27.2	8.2%
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	22.8	21.9	23.8	25.6	1.7%
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	22.8	21.4	23.2	23.5	-6.5%
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	22.8	21.4	22.9	23.3	-7.4%
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	22.8	21.4	23.8	24.1	-4.3%
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	22.8	21.4	23.7	24.0	-4.7%

By 2050 all hydrogen scenarios resulted in more expensive electricity prices than the base case scenario, this was estimated to cost consumers between $1.5 and $2.5 billion per year in additional electricity costs when compared to the base case[45]. All Onslow scenarios resulted in cheaper residential electricity prices when compared to the base case. For example, in Christchurch the final residential electricity price in the worst Onslow scenario was still 1.2 c/kWh lower than the base case. In Auckland, the worst Onslow scenario still reduced electricity prices by 0.2 c/kWh for end consumers.

Results show that industrial, commercial and agricultural electricity prices decline by between 1.2% and 5.5% in Auckland and between 4.3% and 11.5% compared to the base case scenario. All SGH scenarios lead to higher electricity prices for final consumers in both Auckland and Christchurch. All Onslow scenarios show a

[44] These prices do not include GST

[45] This estimate is provided in real, undiscounted values.

reduction in electricity prices. Larger reductions in Christchurch can be explained by the fact that Onslow is located in the South Island and thus Christchurch receives a higher share of the locational benefit.

It is important to note that while the differences in electricity prices between the scenarios amounts to just a couple of cents per kWh, the aggregate total costs are significant. In 2050 the average electricity price in the Onslow 'high-50 years' in Christchurch ranges from a saving of between 1 and 1.2 c/kWh across residential, commercial, industrial, and agricultural consumers. While 1-1.2 c/kWh does not sound like a lot, when this is multiplied out by the 23 TWh of predicted demand in the South Island in 2050 it represents a saving to consumers of roughly $230-276 million per year by 2050. For the 'Low-100' years scenario average savings range between 1.8-2.1 c/kWh giving a total annual system wide savings of $414-483 million. The Auckland Onslow 'low-100 year' scenario has a saving of approximately 1.1 c/kWh when compared to the base case, and when multiplied by the predicted demand for the North Island of 40 TWh it will save consumers an estimated $440 million per year by 2050 when compared to the base case.

Seeing how the residential electricity prices have an effect on consumer electricity bills is informative. Using the average annual electricity consumption of a typical New Zealand household of 7,261 kWh per annum it is possible to estimate the annual costs (black) and savings (red) for an average residential consumer. These are shown in Table 12 for Auckland and Table 13 for Christchurch.

Table 12: Average annual costs (savings) on residential consumer electricity bills in the North Island (Auckland)

Annual saving (cost) for average Auckland residential electricity bill	**2020**	**2030**	**2040**	**2050**
Base case (average electricity bill for NZ household 7,261 kWh per annum)	$2,271	$2,158	$2,259	$2,360
Average annual savings compared to base case (red means reduction in electricity bill)				
Scenario 1: Tiwai closes	$0.0	-$63.8	-$50.2	-$52.0
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	$0.0	$33.2	$18.4	$43.5
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	$0.0	$51.7	$70.3	$72.9
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	$0.0	$35.6	$20.5	$45.3
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	$0.0	$53.8	$72.2	$74.6
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	$0.0	$14.2	-$0.5	-$63.1
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	$0.0	$14.2	-$20.5	-$80.7
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	$0.0	$14.2	$52.9	-$16.3
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	$0.0	$14.2	$42.7	-$25.2

Table 13: Average annual costs (savings) on residential consumer electricity bills in the South Island (Christchurch)

Annual saving (cost) for average Christchurch residential electricity bill	**2020**	**2030**	**2040**	**2050**
Base case (average electricity bill for NZ household 7,261 kWh per annum)	$2,243	$2,175	$2,342	$2,505
Average annual savings compared to base case (red means reduction in electricity bill)				
Scenario 1: Tiwai closes	$0.0	-$123.0	-$157.7	-$197.5
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	$0.0	$42.6	$91.5	$170.6
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	$0.0	$48.6	$44.9	$29.8
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	$0.0	$45.1	$93.5	$172.4
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	$0.0	$50.7	$46.7	$31.4
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	$0.0	$16.7	-$0.3	-$132.9
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	$0.0	$16.7	-$20.3	-$150.5
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	$0.0	$16.7	$53.1	-$86.1
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	$0.0	$16.7	$42.9	-$95.0

Economic analysis

By applying a basic financial cost-benefit analysis it is possible to compare the costs and benefits of each scenario at a system level. The financial model uses average annual electricity prices and aggregate electricity demand for each of the five pathways to estimate system wide costs. System wide costs are estimated by multiplying the annual residential electricity price with total electricity demand in any given year. The final electricity price is assumed to include the carbon price, the cost of capital for building new generation, as well as transmission and distribution costs and retail margins. It also includes the cost of constructing Onslow, the development cost of building new electrolysers for the production of hydrogen and the cost of swaption contracts to curtail hydrogen demand in periods of high electricity demand. It does not include the costs of hydrogen storage or the transportation of hydrogen which is assumed to be outside of the electricity system. The development of other related hydrogen infrastructure is assumed to be developed purely on commercial grounds for the export of hydrogen and therefore these costs are not recovered through residential electricity prices.

Table 14: What is included and excluded from this CBA analysis

Included in CBA analysis
Cost of capital for new generation and the resulting impact on electricity prices
Operation and maintenance costs of different generation resources across the network
Transmission and distribution infrastructure (assumed same for all pathways)
Onslow construction costs and the resulting impact on electricity prices
Southern Green Hydrogen electrolyser costs and the impact on electricity prices
Effects of price volatility on wholesale electricity prices
The effective carbon price to achieve net zero targets as recommended by the CCC

Excluded from CBA analysis
Supply of last resort costs (SLR)
The cost of rolling blackouts or extended periods of insufficient generation supply
The cost of market-based uncertainty and risk
The effects of market power and rent seeking
Demand response from the new TPM[46]
Changes to LCOE (e.g. lower cost of capital for renewables)
Differences between pathways in transmission and distribution infrastructure
The sale revenue from hydrogen or aluminium
Tax and dividend payments to government from the sale of aluminium, hydrogen and electricity generation
Optimisation of Onslow based on improved inter-annual climate predictions

The following section develops a simple financial model showing the system wide costs and benefits for each scenario.

[46] The Electricity Authority have released new rules on incentivising increased demand response across the network https://www.ea.govt.nz/projects/all/tpm/

The Energy Link model provides electricity price estimates for Auckland and Christchurch which are used as proxies to estimate total electricity costs for the North and South Island respectively. For simplicity it is assumed that 62.7% of electricity demand occurs in the North Island and 37.3% of electricity demand occurs in the South Island – which is approximately correct. End consumers are split into four categories for both the North and South Island. These are: residential, industrial, commercial and agricultural consumers. In order to estimate the total cost of electricity consumed in the North Island it is necessary to multiply the residential electricity price in Auckland with total electricity demand in the North Island for each of the different electricity consumer categories[47]. The total nationwide cost of electricity consumption is then estimated by summing the total cost of electricity delivered to each category of consumer in the North and South Island respectively. This is repeated for each scenario and for each year of analysis until 2100.

Onslow is a long-lived asset and could potentially operate for 100 years or more assuming it was well maintained, and electrical components were replaced when required (we assume the cost of operation and maintenance is $42 million per year). It is therefore important to capture the costs and benefits to society over the full economic life of the asset. The WACC and the discount rate are both affected by the period over which the analysis is undertaken. In order to test the sensitivity of the modelling period to the final results, two modelling periods were assessed: one where construction costs were fully recovered over a 50-year period and another where costs were recovered over the full life of the asset, estimated at 100 years. Both periods were assessed using two weighted average cost of capital estimates and three discount rates.

Given that the modelling completed by Energy Link only estimates model outputs until 2050, it is necessary to extrapolate model outputs between 2050 and 2100 to allow for the extended economic life of Onslow. It is therefore assumed that real electricity prices are maintained at their 2050 levels between 2050 and 2100. This is a conservative assumption given that electricity prices over the previous period to 2050 increase in real terms. There are equally justifiable arguments for why electricity prices may either increase or decrease in real terms beyond the period of 2050 to 2100. Beyond 2050 it is assumed that electricity demand continues to increase at a much slower pace of 1% per year as the more capital-intensive transition to net zero will have already occurred (assuming government net zero targets are met).

Arriving at an estimate for the overall net benefits (costs) to society requires that total costs are deducted from total benefits. Figure 36 shows the undiscounted costs and benefits for each scenario. In this analysis, only the financial costs and benefits from changes in wholesale electricity prices are included (after taking into account all levies and charges). It is only when there is a difference in the costs and benefits between the base case and a scenario that there will be a different economic result. As the electricity price includes all system wide financial costs and benefits for a given scenario (including the construction of Onslow and hydrogen electrolysers), it is a useful estimate of the system wide economic net costs and benefits[48]. It is important to note that values in Figure 36 have not been discounted, a discount rate is applied when estimating the net present value and this is shown in the next section.

Given the number of pathways and sensitivity scenarios performed, Figure 36 shows the best and worst cases from each pathway. It is clear from Figure 36 that closing the Tiwai Point aluminium smelter has an immediate social net-benefit as it reduces aggregate demand for electricity, immediately lowering electricity prices across the network, which means less cost to society from generating electricity from other sources of electricity generation. This happens because electricity from Manapouri would flow north, reducing the need to generate electricity from other sources thus reducing system wide economic costs. Surplus electricity has the effect of placing downward pressure on wholesale electricity prices. This financial model does not factor in other economic benefits derived from operating the Tiwai Point aluminium smelter such as the financial benefits of producing and exporting aluminium or other employment benefits. However, this analysis does suggest that

[47] The majority of electricity in the North Island is consumed in Auckland and while prices do vary across the North Island it is not necessary to provide this level of resolution to undertake the level of economic analysis being considered.

[48] A more comprehensive social cost benefit analysis would be a valuable addition to this purely price driven analysis.

Tiwai Point would need to contribute between $1.5 and $2 billion in net benefits to society annually to match the benefits that society would receive from lower electricity costs if Tiwai Point were shut down[49].

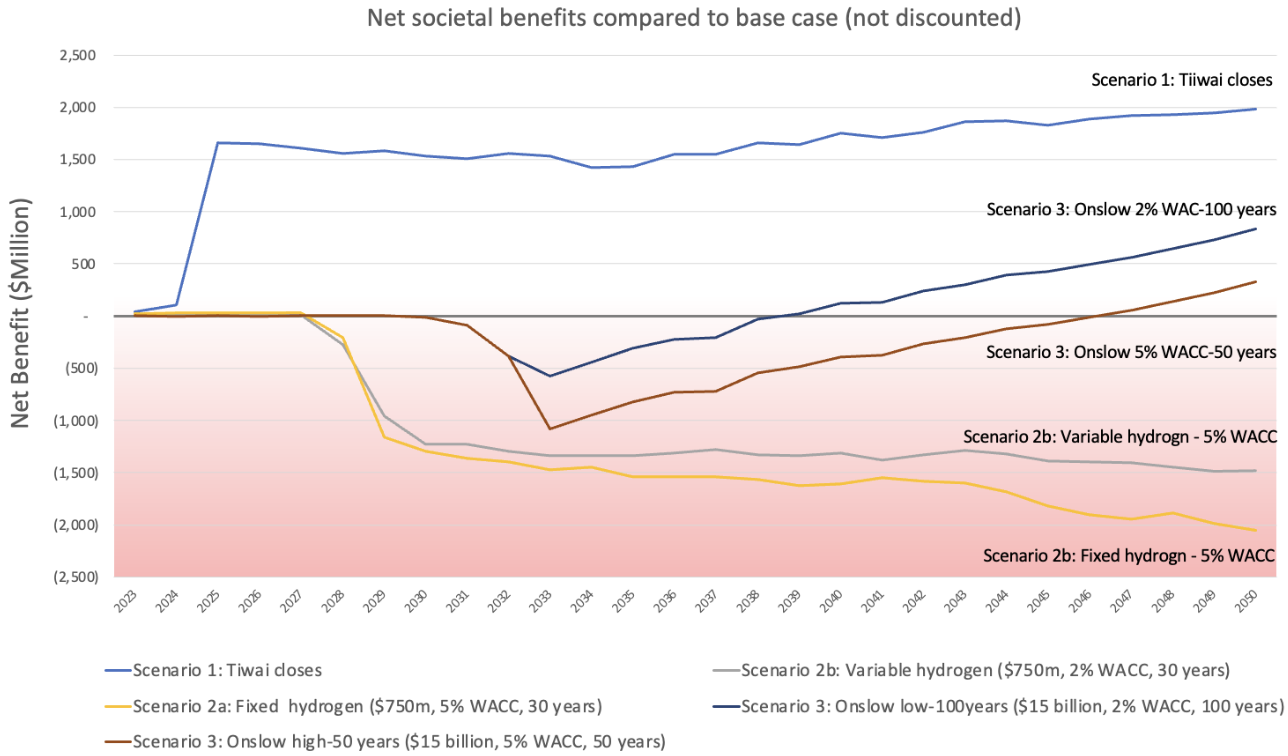

Figure 36: Net social costs and benefits compared to base case (undiscounted)

The four Onslow scenarios are shown to be a net cost on society for the first several years before turning to a net benefit. The Onslow 'low-100 years' scenario (CAPEX of $15 billion, 2% WACC, 100-year asset life) turns to a 'public' net benefit in 2039, while the worst Onslow scenario 'high-50 years' (CAPEX $15 billion, 5% WACC, 50 years) turns to a 'public' net benefit in 2047, 15 years after it is operational. These calculations allow for the full capital cost recovery of Onslow where the residual cost of capital is financed through a levy directly on consumers electricity bills[50]. The cost recovery factor levied on consumer bills ranges from 1.73 c/kWh in 2032 to 0.11c/kWh in 2050 depending on the financial assumptions used. As shown in the following cost benefit analysis, the capital cost of Onslow is completely offset through lower overall electricity prices to consumers (see

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[49] This does not include other economic benefits to New Zealand from the sale of aluminium.

[50] The Cost Recovery Factor (CRF) is calculated using the following formula: $CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ where i is the real WACC and n is the number of annuities received (or the expected life of the asset)

Table 8 Table 9).

The capital cost of installing electrolysers to produce hydrogen (excluding hydrogen transport and storage infrastructure) is much lower than the capital cost of constructing Onslow (only $750 million for building a 500MW hydrogen production facility compared to an estimate of around $15 billion for constructing Onslow. All hydrogen scenarios remain a net cost to society (the benefit-cost ratio is below 1) throughout the modelling period. This is because hydrogen generation is very inefficient requiring around twice as much renewable energy to produce each kWh of hydrogen, increasing aggregate demand on the network and a need for significant additional renewable generation thus leading to an increase in electricity prices for end consumers. The benefits of operating hydrogen in flexible mode does improve the economics but not sufficiently to make the installation of hydrogen production worthwhile. Like the Tiwai Point scenario, other economic benefits like the revenue that would be generated through the production of hydrogen for export have not been included as part of this cost benefit analysis. Like Tiwai Point the benefits of selling hydrogen on export markets would need to exceed between $1.5 and $2 billion per annum for the system wide benefits to stack up.

Applying discount rates of 7%, 5% and 2% using both exponential[51] and hyperbolic[52] discounting it is possible to estimate the Net Present Value (NPV) of each scenario. The NPV is a single number that sums the discounted net benefits and costs over the assumed modelling period. When interpreting the NPV results, a negative value indicates that a scenario is more costly than beneficial to society over the modelling period, while a positive value shows it will have an overall net benefit to society when compared with the base case.

Table 15 shows the NPV over a 50-year time horizon (i.e. until 2073) for all scenarios. This analysis shows that all hydrogen scenarios return negative NPVs for all discount rates using both constant exponential and hyperbolic discounting. Onslow returns a positive NPV when a 2% WACC is used for both 50-year and 100-year time periods for all discount rates.

Like discount rates, a broader conversation needs to occur on what the right cost of capital or expected financial return is required for a long-lived infrastructure that has both social and environmental benefits like a PHES. The Commerce Commission guidelines on the use of WACC for network infrastructure suggest a range in nominal WACC of 3.78% to 4.13%[53]. Given the WACC values used in this analysis are real values, they can be considered conservative and a lower WACC would go a long way to improve the financial justification for capital-intensive assets with a long life.

Table 15: Net Present Value for different scenarios over a 50-year time horizon (until 2073)

[51] The discount factor for constant exponential discounting was estimated using $W_t = \frac{1}{(1+r)^t}$ where W_t is the discount factor for period t and discount rate r

[52] The discount factor for hyperbolic discounting was estimated using $H_t = \frac{1}{(1+rt)}$ where H_t is the discount factor for period t and discount rate r.

[53] https://comcom.govt.nz/__data/assets/pdf_file/0022/177034/2019-NZCC-12-Cost-of-capital-determination-EDBs-and-Transpower-25-September-2019.PDF

Until 2073 (Discounted over 50 years)						
Net Present Value (2022NZD $million) (red is negative NPV)	**Constant exponential discounting**			**Hyperbolic discounting**		
	7%	**5%**	**2%**	**7%**	**5%**	**2%**
Scenario 1: Tiwai closes	20,686	29,138	55,756	35,945	42,931	62,443
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	(14,946)	(22,849)	(48,648)	(30,077)	(36,631)	(55,401)
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	(12,382)	(18,536)	(38,185)	(23,794)	(28,854)	(43,184)
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	(15,081)	(23,051)	(49,063)	(30,335)	(36,945)	(55,870)
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	(12,499)	(18,712)	(38,550)	(24,020)	(29,129)	(43,596)
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	528	1,885	7,704	4,283	5,554	9,692
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	1,496	3,408	11,037	6,317	8,045	13,495
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	(2,052)	(2,174)	(1,178)	(1,138)	(1,083)	(442)
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	(1,560)	(1,400)	517	(103)	184	1,492

Table 16 presents the same results but extends the time horizon of the cost benefit analysis to 2123 (100 years from today). This analysis confirms that the time-period over which the financial analysis is undertaken for long-lived infrastructure projects can have a significant effect on the financial results and therefore the conclusions of the analysis. Over this longer period, SGH becomes even more uneconomic as the costs of hydrogen production compared to the base case continue to mount, even after they have been discounted. Onslow on the other hand improves its economic position as the benefits of efficient, seasonal and flexible energy storage continue to grow as the scale of variable and intermittent renewable generation also expands across the network and the costs of increased volatility are mitigated. It is only at the at discount rates of 7% and 5% in the Onslow 'high' scenarios where the costs of Onslow exceed the benefits. In all other cases Onslow returns higher net economic benefits across all discount rates and scenarios. This analysis also shows that hyperbolic discounting, an approach that puts more weight on the costs and benefits of long-lived assets, returns a positive NPV across all discount rates for Onslow.

Table 16: Net Present Value for different scenarios over 100-year time horizon (2123)

Until 2123 (Discounted over 100 years)						
Net Present Value (2022NZD $million) (red is negative NPV)	**Constant exponential discounting**			**Hyperbolic discounting**		
	7%	**5%**	**2%**	**7%**	**5%**	**2%**
Scenario 1: Tiwai closes	21,943	33,614	91,416	61,550	76,599	126,364
Scenario 2a: Fixed hydrogen ($750m, 2% WACC, 30 years)	(16,236)	(27,444)	(85,254)	(56,361)	(71,192)	(121,018)
Scenario 2b: Variable hydrogen ($750m, 2% WACC, 30 years)	(13,319)	(21,872)	(64,765)	(42,879)	(53,949)	(90,829)
Scenario 2a: Fixed hydrogen ($750m, 5% WACC, 30 years)	(16,380)	(27,681)	(85,950)	(56,821)	(71,771)	(121,991)
Scenario 2b: Variable hydrogen (($750m, 5% WACC, 30 years)	(13,445)	(22,080)	(65,381)	(43,285)	(54,461)	(91,691)
Scenario 3: Onslow low-50years ($15 billion, 2% WACC, 50 years)	967	3,451	20,177	13,239	17,331	32,051
Scenario 3: Onslow low-100years ($15 billion, 2% WACC, 100 years)	2,023	5,285	25,993	17,056	22,165	40,303
Scenario 3: Onslow high-50 years ($15 billion, 5% WACC, 50 years)	(1,846)	(1,439)	4,681	3,069	4,449	10,061
Scenario 3: Onslow high-100 yeaers ($15 billion, 5% WACC, 100 years)	(1,309)	(506)	7,638	5,010	6,907	14,258

This analysis highlights the sensitivity of different parameters used in financial analysis for long-lived-lived projects. The Parliamentary Commissioner for the Environment has already advised the Treasury[54] to consider using hyperbolic discount rates for long-lived assets. Doing so for Onslow would appropriately weight the longer-term costs and benefits of the project to future generations.

Discussion

The electricity sector in New Zealand is primed to undergo its largest system transformation for generations. The electrification of transport, heating and industrial processes will require the development and installation of new renewable electricity resources at growth rates that exceed historical trends. Intermittent and variable renewable energy resources place new challenges on an electricity system that has historically relied on fossil fuels and large centralised generation to meet peak and seasonal demand requirements.

[54] https://pce.parliament.nz/publications/wellbeing-budgets-and-the-environment/

Volatility in wholesale markets is set to increase alongside growing shares of variable renewable electricity. Without intervention, increased market volatility in wholesale electricity prices will occur at all timescales (daily, weekly, seasonally and interannually) increasing the cost of delivering electricity to end consumers. These risks are most pronounced during a dry year when hydroelectricity dams are not able to meet demand.

This research explored three potential solutions for managing system risks, namely:

- Closing down the Tiwai Point aluminium smelter and releasing energy from Manapouri into the electricity network
- The development of a Southern Green Hydrogen (SGH) production facility
- Construction of a pumped hydroelectricity storage system at Lake Onslow.

All three options will have vastly different impacts on the national electricity system.

Pathway 1: Closing Tiwai Point

A key advantage of the Tiwai Point aluminium smelter closing thereby allowing the electricity from Manapouri dam to flow into the wholesale electricity market is that there are no major new construction or development costs beyond marginal new generation capacity[55], making this pathway the lowest cost option. The primary costs for closing Tiwai Point are the lost tax revenues to government from the export of aluminium and lost wages to staff working at the smelter as well suppliers, contractors and other flow-on effects to the economy. However, these costs were not included in this economic analysis. This pathway produces the lowest residential electricity price and results in the highest NPV over the modelling period when compared with the other scenarios giving this pathway the highest economic benefit. This pathway also brings down emissions the fastest over the first decade, but emissions slowly rise again towards 2050 as new fossil powered flexible generation is required to manage supply intermittency and dry year risk.

Pathway 2a and 2b: Southern Green Hydrogen

The development of SGH was analysed using two operating modes, fixed supply, and variable supply. We assume that all hydrogen is exported as the domestic market for hydrogen is undeveloped. The cost of transporting, storing and shipping hydrogen were excluded from this analysis. Hydrogen is not used for the generation of electricity in this pathway because hydrogen for power generation is still a new technology that is under active research and development. Furthermore, the round-trip efficiency of hydrogen generation for electricity production is just 30% which makes it a particularly unattractive economic investment when compared with more efficient storage technologies. Flexibility to the grid was therefore provided through curtailment of hydrogen production. This assumes sufficient generation capacity is available on the grid from intermittent renewables to meet supply shortfalls. This is one assumption of the analysis that needs further assessment as it cannot be guaranteed that renewable generation will be available when required (i.e. still cloudy days) thus the need to fall back on flexible gas generation or rely on other expensive curtailment options. On the upside, hydrogen production is scalable and new electrolysers can be added as required.

An assessment of 'supply of last resort' (SLR) shows that between 35 and 54 GWh of SLR is required to provide sufficient grid security in the hydrogen pathway – but this comes at a high cost estimated to be around $200 million per year in the SGH fixed scenario. While the variable hydrogen pathway performs much better than the fixed scenario, all hydrogen options result in the highest residential electricity prices for end consumers. The NPV from the economic analysis was negative for both scenarios. Surprisingly, the

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[55] Transpower recently upgraded the grid in the lower South Island to allow for the possibility of Tiwai Point closing. This is a sunk cost that applies to all pathways.

hydrogen scenarios had little effect on dampening seasonal price volatility. Emissions in the fixed pathway were higher than the base case because new flexible fossil generation would be required to meet demand requirements. The variable pathway had lower emissions than the base case, as was expected. The sheer quantity of new renewables that would be required to support the development of a Southern Green Hydrogen project without the closure of Tiwai Point, would push electricity infrastructure in the South Island to its absolute limits requiring significant grid upgrades to occur. These additional costs were not allowed for in this analysis.

Pathway 3: Onslow pumped hydroelectricity storage

One downside to Onslow is that it will likely take the best part of a decade before it reaches full operating capacity. However, our analysis suggests this does not necessarily come at the cost of grid reliability and security as SLR remains low throughout the modelling period when compared to the alternative pathways. While it is acknowledged this analysis does not allow for the probabilistic analysis of risks, it does show that the existing fleet of flexible generation is sufficient to meet predicted demand while Onslow is being constructed. In this modelling, Onslow is assumed to always operate in flexible mode, interacting with the electricity system to pump when prices are low and generate when prices are high. This places an effective upper limit on wholesale prices and an effective floor price that limits extremely low or negative wholesale prices that could be detrimental to investment in renewables. Onslow effectively smooths out market volatility across all time periods, but most extensively on a seasonal basis. As Onslow would be a large flexible resource, it would effectively avoid the construction of more expensive flexible generators and cause existing flexible generators such as fossil gas-peakers to exit the electricity market sooner. This has the effect of driving down future emissions resulting in the lowest aggregate emissions of all pathways over the modelling period.

By pumping when prices are low, an effective lower limit or floor is maintained on wholesale electricity prices. Onslow also reduces peak prices which tend to occur during periods of low renewable availability. This will benefit wind and solar generation which are ‘price takers’. While renewables also benefit from higher prices, these periods tend to occur when there is lower opportunity for renewables to generate. An effective floor price will, on average, increase the overall efficiency of wind and solar generation, reducing the time over which costs must be recovered lowering the overall cost of capital for investment in new renewables. The economic benefits of a lower cost of capital for renewables has not been included in this economic analysis and could be substantial – further research here is therefore warranted and the benefits of this should be included in future cost benefit analysis calculations for Onslow.

Seasonal price volatility is shown to dramatically decrease in the Onslow scenario, which represents a little more than half the price volatility when compared with the other pathways. Onslow also produces the lowest wholesale electricity prices once it reaches normal operation. There is a blip in prices between 2032 and 2033 while the dam is filling, but this could be managed by implementing new rules that determine when the dam was allowed to fill to avoid driving up short-term prices. This would likely extend the time it takes to fill the dam and add to dry year risk over this period. A comprehensive risk analysis is therefore recommended to optimise the management of Onslow over this initial operating period.

Residential prices in the North and South Island were shown be lower than the base case over the modelling period. This was because Onslow was able to absorb renewable energy generation that would otherwise have been curtailed thereby increasing the value of electricity generated from renewables and improve efficiency. When stored electricity was released during peak periods, it also limited the need for the construction of new flexible generation that was needed in the other pathways to meet demand.

An economic assessment of costs and revenues show that Onslow would generate net annual revenue of up to $150 million per year by 2040 and up to $250 million per year by 2050, depending on the extent of grid upgrades undertaken.

Assuming that construction costs are recovered through electricity prices, the economic viability of Onslow is subject to the sensitivity of various financial input assumptions. Sensitivity testing was therefore applied to three input parameters, namely: weighted average cost of capital (WACC), analysis period (life of asset), discount rate and discount rate methodology. Over a 100-year discount period, Onslow returned a positive NPV for with a real WACC of 2% for constant exponential discount. When using hyperbolic discounting Onslow returned a positive NPV for all scenarios.

The importance of removing constraints across the network was shown through the differences in revenue generated by Onslow when comparing the wholesale prices for three nodes on the network. On an unconstrained electricity network Onslow would be able to sell and purchase electricity at any point on the network with electricity system losses being the only penalty of the transaction. These results suggest the electricity system is substantially constrained as indicated by the large difference in wholesale electricity prices between the Auckland node and the Roxborough node. If Onslow is built, some grid infrastructure upgrades will need to occur. A range in Onslow revenues was estimated taking into account the best and worst cases of network infrastructure upgrade.

Conclusion

A comprehensive assessment evaluating the potential system wide impacts of four distinct electricity transformation pathways was undertaken. These pathways are indicative of the pivotal system wide decisions to be made over the next few years, influencing environmental, economic, societal, and climate outcomes for generations to come.

The analysis utilised Energy Link's electricity system model and market dynamics model to forecast the effects of electricity supply and demand under each pathway and the expected impacts across the system using a range of metrics. Outputs of this analysis included impacts to wholesale and consumer electricity prices, CO_2 emissions, price volatility, energy security, and peak demand. Each pathway was also tested against a range of sensitivity settings to gauge how different assumptions may lead to different economic and financial conclusions.

With a carbon price that is scheduled to rise to meet net zero emissions targets, investment in new renewable generation will be required to meet the roughly 20 TWh growth in new electricity demand between now and 2050. Contrary to prevalent beliefs, a high penetration of renewables, paired with a robust security of supply strategy, did not have adverse effects on future system wide costs and electricity prices. Indeed, both Pathway 1 (Tiwai Point smelter closes), and Pathway 3 (Onslow) were shown to produce lower overall electricity prices than the base case scenario.

Pathway 1: Tiwai Point closes and Pathway 3: Onslow were the only scenarios to produce a positive net present value depending on the financial assumptions chosen. For Tiwai Point, this suggests that the system wide costs of allowing Tiwai Point to remain are high in a low carbon, intermittent electricity system. For Onslow, it suggests that even though there are high upfront capital costs, they are outweighed by the system wide benefits of lower wholesale electricity prices. It is also worth noting that the assumptions in this analysis are conservative as they do not account for the associated costs of dry year risk and system wide outages, the concentration of market power, spill-over effects from lower cost of capital for renewable generation or the optimisation of operating Onslow from improved multi-year climate predictions.

The analysis indicates that capital intensive, long-lived infrastructure projects like Onslow are particularly sensitive to the financial assumptions used. When financial analysis allows for the full-life of the asset (consistent with an intergenerational wellbeing approach) the financial viability of the project improves when it is paired with appropriate cost of capital and discount rate assumptions. Assuming truncated asset lifetimes for long-lived infrastructure (such as Onslow) therefore biases economic assessments in favour of shorter-lived assets. Undertaking a consistent and fair comparison of different options thus requires analysis over the full expected life of the asset.

In light of the above, the following recommendations should be applied to future analysis:

- **Full transparency and disclosure of modelling assumptions.** This includes the cost of capital, discount rates, asset lifetimes, operation and maintenance expenditure, investment in transmission and distribution infrastructure, future demand and any assumptions about the evolution of the generation mix.
- **Use the full asset life in financial and economic calculations.** For long-lived infrastructure projects, the full life of the asset and its potential need for replacement should be used in financial calculations to avoid biasing a preference for short-lived assets.
- **Better assessments on the full cost of dry year risk.** It is necessary to provide robust estimates of the costs of not resolving dry year risk and extended periods of electricity supply shortfall. Prolonged periods of electricity supply disruption can lead to significant economic impacts and have wide-ranging implications for civil society[56].
- **Use hyperbolic discounting or low discount rates for long-lived assets.** Where social and environmental benefits are shown these should be subjected to hyperbolic or low discount rates instead of higher discount rates that use constant exponential discounting. When comparing assets of different lifetimes, it is acceptable to use the same lower discount rate for all projects for comparison purposes.
- **The expected return on an asset should be consistent with the primary funders' expectations.** Estimates for the cost of capital should take into account the return that the primary investors in the project would expect for their investment. If the investor is primarily government, then it is justifiable to use a lower expected rate of return over the investment period, particularly if the investment is seen to offer other system wide benefits, such as security of supply as well as social and environmental benefits. The Commerce Commission already recognises a relatively low WACC rate for investment in distribution and transmission infrastructure.
- **Include all other material costs and benefits in financial and economic calculations.** These include: (1) an assessment of the likely impacts of market power, (2) an assessment of any spill-over effects such as reductions in the cost of capital of renewable electricity, (3) the costs and benefits of network infrastructure upgrades under different pathways (4) the optimisation of Onslow using medium-range weather and climate prediction models.

In conclusion, this analysis shows that each electricity system pathway has varying strengths and weaknesses, which in turn depend on the modelling assumptions used. Before any pathway is taken off the table, or indeed put forward as the preferred option, it is important that a complete and fair assessment has been completed, analysis is publicly released and then available for public scrutiny.

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[56] Kelly, Scott. 2015.Business Blackout – emerging risk report. https://www.jbs.cam.ac.uk/faculty-research/centres/risk/publications/technology-and-space/lloyds-business-blackout-scenario/

Appendix A: Model assumptions

- The electricity market remains an energy-only market in which generators derive their revenue from the spot market along with payments on hedge contracts which are related to expected spot prices.
- No extra mandatory costs directly affect spot prices.
- All generator offers and resulting prices are expressed in nominal terms, which are then converted back into real prices.
- Hydro generators will manage reservoirs to achieve dry year security under all historical inflow scenarios back to April 1931.
- Reservoir storage is started at actual levels from June 2022. For all other years starting storage is determined from the end of the previous modelled year.
- No consideration of any short-term generator strategy that may influence spot price outside of normal market conditions.
- Dry year reserve generation initially offered as 155 MW at $450/MWh at Whirinaki. In later years the offer price is increased.
- Other small generators are offered to ensure dispatch to realistic schedules.
- All generators offer below maximum capacity to reflect planned and unplanned outages.
- The profile of demand within each year is based on actual demand in the year ending March 2020.
- The HVDC maximum flow is modelled as 1,400 MW northward and 700 MW southward. The northward capacity assumes that lithium batteries are commissioned in the North Island to provide additional reserve support for HVDC transfers[57].
- All scenarios where Tiwai Point remains, Tiwai Point demand is modelled at 572 MW of demand except during dry periods when it is modelled as reducing demand for up to three months at a time.
- The Southern Green Hydrogen scenario is treated in a similar fashion, except that demand reductions happen more often but generally for shorter periods.

[57] Transpower may upgrade this to 1,400 MW when the Cook Strait cables are replaced sometime within the next decade, depending on the economic and security assessment to be completed at the time.