Non-utility Solar-BESS Uptake Market Impact Study

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Executive summary

This report presents the findings of market modelling and analysis commissioned by the Ministry of Business, Innovation and Employment (MBIE) to evaluate the impact of large-scale distributed solar uptake on the New Zealand Electricity Market (NZEM). The study specifically examines the impact of rapid and widespread uptake of solar and battery energy storage systems (BESS) on grid-scale generation expansion, spot market prices and supply costs.

Using Jacobs electricity market modelling toolset considering hydro and variable renewable energy (VRE) uncertainty, we simulated three scenarios:

- Jacobs Base Case: Our central view of New Zealand Electricity Market (NZEM) evolution to 2055, aligned with the Climate Change Commission's electrification pathway but incorporating Jacobs' projections of capital costs and grid-scale generation development.
- Rewiring Aotearoa Case 1: A sensitivity analysis based on Rewiring Aotearoa's non-utility solar uptake figures.
- Rewiring Aotearoa Case 2: A sensitivity that targets a similar end point in non-utility solar uptake as in the previous case, but with the rate indexed to demand growth to avoid extended period of greater supply than demand.

The graph below presents the non-utility solar and BESS uptake assumptions in each case, where the Base case is drawn from Jacobs Base case assumptions and Rewiring 1 and Rewiring 2 reach penetration levels provided by Rewiring Aotearoa at different rates.

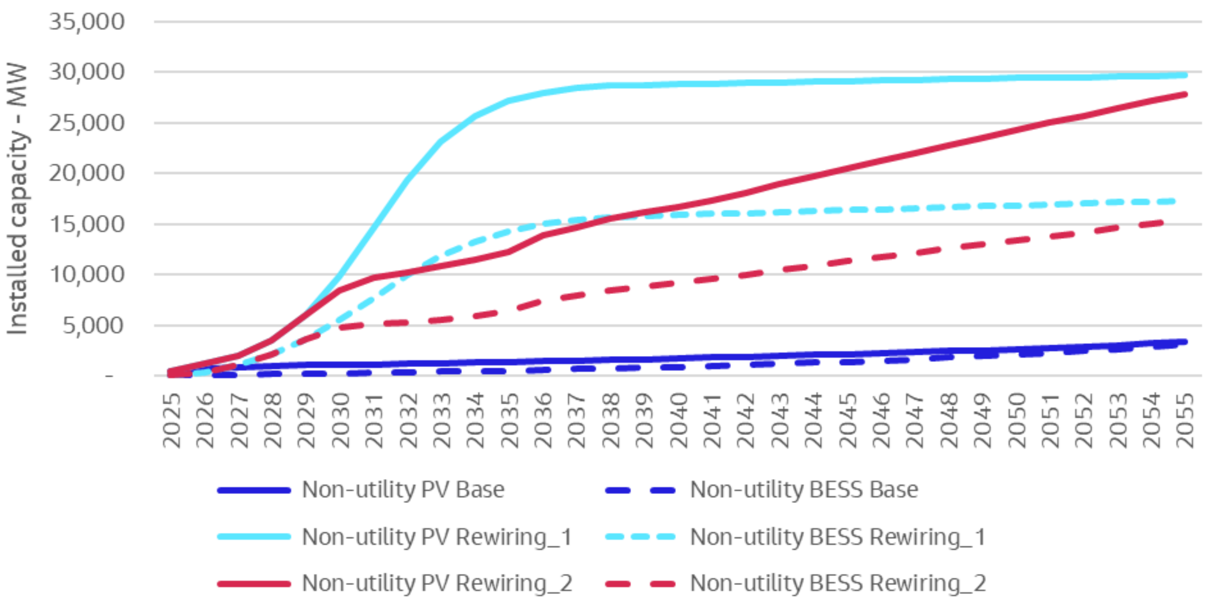

Figure 1. Non-utility solar and BESS assumptions by case

1.1 Grid-scale Generation Capacity and Generation

The analysis of increasing distributed solar generation reveals significant impacts on the development of other generation capacity in New Zealand's electricity system:

1. Delayed Grid-Scale Build: In both Rewiring scenarios, the high uptake of distributed solar substantially delays the need for new grid-scale generation capacity. This delay extends into the

mid-2030s for the rapid uptake case (Rewiring 1) and the mid-2040s for the slower uptake case (Rewiring 2).

2. Reduced Diversity in New Builds: The prevalence of distributed solar leads to a less diverse generation mix. New wind and geothermal projects, which feature prominently in the Base Case, are significantly delayed or deferred beyond the end of the modelling horizon in both the Rewiring scenarios.

3. Thermal Generation: The need for new thermal generation capacity to firm the hydro and solar generation remains and may increase due to the reduced diversity of variable renewables and low solar output over winter.

4. Existing Asset Utilization: Higher levels of distributed solar lead to reduced utilization of existing generation assets, particularly during summer. This could impact on the economic viability of some existing plants.

1.2 Electricity Prices

The analysis of large-scale distributed solar uptake reveals significant impacts on electricity prices in New Zealand's market:

1. Overall Spot-Price Suppression: Annual average time-weighted average prices (TWAP) tend to be lower in scenarios with higher distributed solar and BESS penetration. This is primarily due to non-utility solar being dispatched at zero cost and not being required to recover their costs from market revenues. By contrast, our generation expansion modelling requires that new grid-scale generation of all technologies recover their capital and operating cost from the market.

2. Potential financial support required for existing capacity: If distributed generation were to materially lead demand growth, as in the Rewiring scenarios in this analysis, existing renewables and thermal plants may require financial support to remain viable and available for when demand growth catches up and/or distributed generation growth slows.

3. Long-term Market Signals: Sustained low prices during the period where supply outweighs demand can dampen investment signals leading to developers de-mobilizing development teams or – in the case of offshore developers – exiting the country. This can result in longer lead times when demand growth catches up and/or distributed capacity growth slows and a sustained period of undersupply and high prices to follow – not dissimilar to the situation that New Zealand is in now where there was little growth for a decade or more, then gas supply steadily reduced creating an under-supply and we are still building to catch up.

4. Generation-Weighted Average Price (GWAP) Impacts:

    4.1 Overall GWAP tends to decrease given an increase in solar uptake, particularly for thermal and baseload generators.

    4.2 Solar generators experience a marked decrease in their GWAP due to correlation in output times.

    4.3 Flexible generators may see higher GWAPs as they capture price spikes during low solar output periods.

5. Potential for Negative Prices: Summer periods in the high uptake scenarios could be a compelling case for negative pricing in the New Zealand Electricity Market as our modelling indicates months-long periods of over-supply during summer. Negative pricing could encourage load into the summer months and long-term storage solutions. Note that negative pricing (rather than zero) could adversely impact must-run plants like geothermal.

1.3 Price Volatility and supply security

1. Increased Seasonal Price Variation: While average prices decrease, the inter-seasonal price variation becomes more pronounced. Summer prices are significantly depressed due to abundant solar generation, while winter prices may spike due to lower solar output and higher demand.
2. Increased Price Volatility: Both TWAP and GWAP exhibit greater volatility, with more extreme highs and lows throughout the year. In particular, the high prices due to energy shortages over winter during dry years are higher in the Rewiring Aotearoa Cases than the Base case.
3. This increased volatility indicates reduced security of supply as generation capacity is exhausted, and the likelihood of curtailment increases.

1.4 Cost of supply

"Cost of supply" here refers to the capital and operating cost of new plant, fuel and carbon costs, and the cost of load curtailment. It does not include network investment, which we understand to be estimated in a parallel workstream. All figures are presented in real 2025 dollars.

Cost of supply over the modelling horizon is $30b greater than the Base case in Rewiring 1 and $14b greater than the Base Case in Rewiring Aotearoa Case 2.

3. The difference is due to the combination of:
   - 3.1 higher cost per MWh of distributed solar and BESS systems relative to grid-scale equivalents, noting that uptake assumptions in the Rewiring Aotearoa Cases are such that wind and geothermal capacity is also displaced,
   - 3.2 Increased spilled energy. The Rewiring Aotearoa Cases spill more energy than the Base Case due to higher levels of solar penetration and insufficient storage to hold it for winter (see note below).

1.5 Water values

1. In all scenarios, water values are impacted by increased penetration of variable renewables and the removal of cheap thermal firming options
2. This leads to the system keeping lake levels higher in the lead up to winter to allow the hydros to mitigate both dry spell risk and firm the VRE,
3. This trend is considerably more pronounced in the two cases with higher distributed solar and BESS penetration for two reasons:
   - 3.1 There is surplus energy during summer, meaning that hydros spend a lot of time operating at the minimum flow levels, allowing the lakes to fill up.
   - 3.2 The reduced diversity and low solar output over winter increases the need for hydro supply over winter.
4. As a result, the Rewiring Aotearoa Cases start winter with higher lake levels than the Base case but need that additional stored water due to the reduced diversity of supply and low solar output over winter. By mid-July or August, lake levels tend to be lower in the Rewiring Aotearoa Cases than the Base case, resulting in the security of supply issues discussed above.

1.6 Conclusions and Next steps

We examined three scenarios of distributed solar and battery uptake in New Zealand: the Jacobs Base Case (reaching 3.5 GW nationally by 2055) and two cases based on Rewiring Aotearoa's projections (achieving approximately 28 GW of distributed solar at different rates).

Outcomes, as outlined above, indicate that:

- Long-term time-weighted average annual spot prices reduce by $10/MWh to $15/MWh in the higher solar uptake scenarios but become more seasonal and more volatile,
- all new grid-scale renewable builds are delayed or deferred to beyond the end of the study horizon, and
- cost of supply is higher by $30b in Rewiring Aotearoa Case 1 and $14b in Rewiring Aotearoa Case 2 relative to the Base Case.

The additional supply-side costs in the Rewiring Aotearoa Cases can be viewed as the savings that would need to be realized in other parts of the system - most likely in transmission and distribution costs - for these higher solar uptake scenarios to potentially deliver a lower overall cost of electricity compared to the Base Case. We understand that estimating the extent of these potential savings is part of a parallel workstream.

Based on the findings of this study, we recommend the following steps to further enhance our understanding of the impact of distributed solar impact on New Zealand's energy system:

1. Transmission and Distribution Network Savings Analysis: Conduct a comprehensive study to estimate potential savings in transmission and distribution network costs associated with increased non-utility solar and Battery Energy Storage Systems (BESS) uptake. This analysis should identify potential tipping points where significant cost reductions may occur.
2. Tipping Point Assessment to investigate critical thresholds in distributed solar and BESS adoption that could lead to substantial changes in network infrastructure requirements and associated costs.
3. Whole-of-energy system modelling: informed by steps above, undertake whole-of-energy-system modelling to assess and establish an optimal path forward for New Zealand's energy system to inform policy and regulation development, and market design.

Caveats and limitations

The outcomes summarised above and included in the body of this report should not be interpreted in isolation of transmission and distribution network savings facilitated by increasing penetration of DER.

Furthermore, should the available transmission and distribution network savings be insufficient to compensate for the increased supply-side cost in our outcomes, this should not be interpreted as rejecting the value of DER in general. Rather, such an outcome should be interpreted as an indication that the Rewiring Aotearoa penetration rates modelled are beyond some "tipping point" where the benefits of DER are outweighed by the costs in the context of the demand scenario used in this study. This provides further incentive to undertake the recommended next steps above, to identify penetration levels where the benefit of non-utility solar and BESS can be realized without unintentionally increasing system costs.

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Acronyms and abbreviations

Acronym	Definition
AC	Alternating current
BESS	Battery energy storage system
CCGT	Combined cycle gas turbine
CNI	Central North Island
DC	Direct current
GWAP	Generation-weighted average price
HVDC	High voltage direct current
LNI	Lower North Island
LSI	Lower South Island
LRMC	Long-run marginal cost
MBIE	Ministry of Business Innovation and Employment
NREL	National Renewable Energy Laboratory
NZEM	New Zealand Electricity Market
OCGT	Open cycle gas turbine
PPA	Power Purchase Agreement
PV	Photovoltaic (solar)
SDDP	Stochastic dual dynamic programming
SRMC	Short-run marginal cost
TWAP	Time-weighted average price
UNI	Upper North Island
USI	Upper South Island
VRE	Variable renewable energy

2. Introduction

This report presents the findings of analysis commissioned by the Ministry of Business, Innovation and Employment (MBIE) to assess the potential impact of large-scale distributed solar uptake on New Zealand's electricity market. The study focuses particularly on the effects on security of supply and electricity prices.

The analysis was prompted by ongoing discussions with Rewiring Aotearoa regarding the benefits of widespread solar installation on rooftops, farms, and businesses. Rewiring Aotearoa's view was that such installations could significantly reduce emissions, increase energy security, and lower the total delivered cost of electricity for all network users.

To evaluate the benefit of non-utility solar and BESS, we employed sophisticated electricity market modelling to simulate three scenarios of distributed solar uptake and generation in New Zealand while considering hydro uncertainty. Our analysis utilized Jacobs' electricity market simulation models, incorporating hydrology considerations and multiple forecasts of supply and demand.

The study examined three primary scenarios:

- Jacobs Base Case: Our central view of New Zealand Electricity Market (NZEM) evolution to 2055, aligned with the Climate Change Commission's electrification pathway but incorporating Jacobs' projections of capital costs and grid-scale generation development.
- Rewiring Aotearoa Case 1: A sensitivity analysis based on Rewiring Aotearoa's non-utility solar uptake figures.
- Rewiring Aotearoa Case 2: A sensitivity that targets a similar end point in non-utility solar uptake as in the previous case, but with the rate indexed to demand growth to avoid extended periods of greater supply than demand.

This report provides quantitative comparisons between these scenarios, focusing on key metrics such as grid-scale generation expansion, generation volumes, average prices (both time-weighted and generation-weighted), price volatility, and security of supply. The following sections detail our methodology, assumptions, and findings, offering insights to inform policy and planning decisions regarding New Zealand's future energy landscape and security of supply.

We emphasize that the modelling presented in this report does not claim to encompass all costs contributing to the total delivered cost of electricity to end consumers. Notably, network investment costs are not included in this analysis and will need to be calculated through a separate workstream.

The value of this modelling lies in providing insights into the magnitude of network investment savings that would be required for the studied levels of rooftop solar to result in lower total delivered costs of electricity. This information serves as a valuable benchmark for future, more comprehensive cost analyses.

It is important to note that if the Rewiring scenarios modelled here do not appear to result in lower total delivered costs of electricity, this should not be interpreted as an indication that the Jacobs Base Case represents the system-optimal level of distributed solar penetration. There may well exist a level of rooftop solar and Battery Energy Storage System (BESS) penetration that is materially greater than the Jacobs Base Case, but lower than the two Rewiring Aotearoa Cases studied in this work, which could prove to be more economically efficient.

The optimal level of distributed solar and BESS adoption likely lies on a continuum, and identifying this point would require additional modelling scenarios and consideration of factors beyond the scope of this study. Future work should explore a wider range of distributed energy resource penetration levels to identify potential sweet spots that balance system costs, network impacts, and overall energy system efficiency, including the dynamic impact of increasing supply or encouraging greater levels of electrification and decarbonisation of the broader energy sector.

This caveat underscores the complexity of determining optimal energy system configurations and highlights the need for ongoing, comprehensive analysis as technology, costs, and system requirements evolve.

3. Methodology

Jacobs NZEM Energy Insights utilises our comprehensive understanding of the NZEM to create a robust market scenario forecast. Our approach recognises the current situation in the market and that wholesale prices should converge to long run entry prices over the long term and ensures that every new entry plant is profitable over its lifetime.

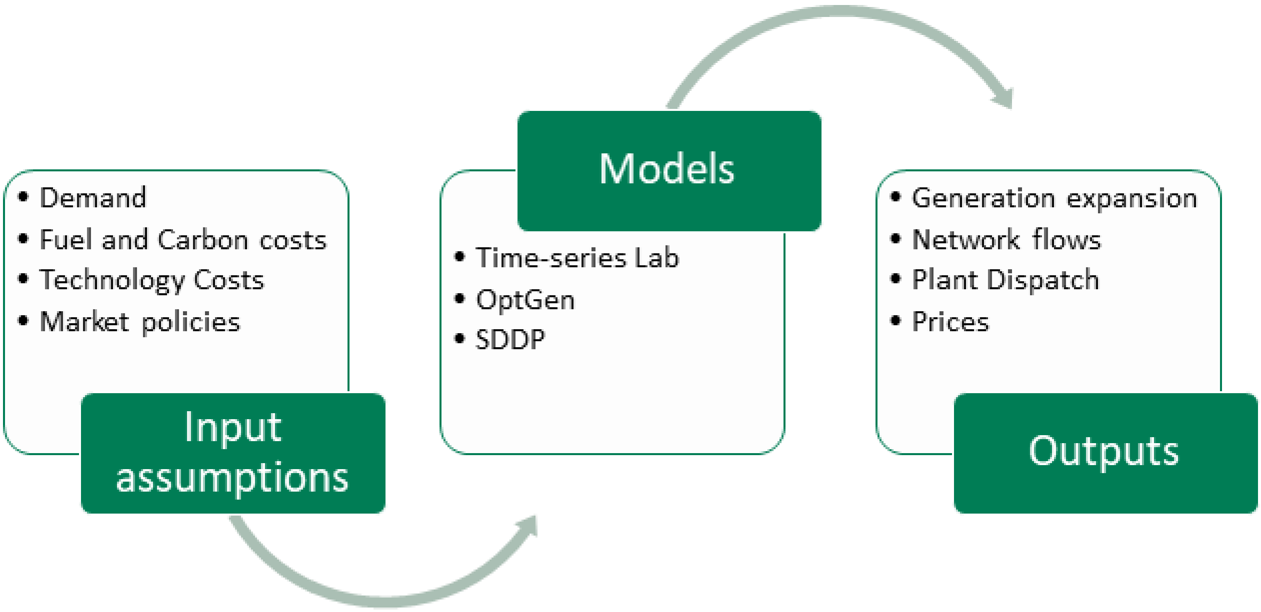


Figure 2. Jacobs market modelling workflow

The approach is to forecast the future generation build in the NZEM using a combination of sophisticated market models and Jacobs' extensive market understanding.

Our approach included:

- An assessment of current trends in the gas and electricity markets, and an outlook of how those trends will develop in the future.
- Development of a Base Case scenario that considers the plausible future development of the electricity and renewable energy markets as expressed through the agreed assumptions. OptGen (described overpage) forecasts produce the quantum of thermal, renewable, and battery capacity build in the NZEM.
- Development of a Variable Case that considers an equally plausible macro-economic evolution of capital costs and gas prices.
- Projecting wholesale electricity prices, time and load weighted on an annual and monthly basis based on agreed assumptions on the:
  - Likely and potential developments in policies affecting the electricity and renewable energy markets. This covered potential developments in carbon mitigation policy, technology support (renewable, energy efficiency) policies, and market reforms.
  - Outlook for demand for electricity, including on the electrification of process heat and transportation, and assessment of potential further uptake of small scale-technologies including storage technologies.

- Outlook for fuel prices namely natural gas and coal based on projected international prices for coal and the local supply and demand balance and storage capacity for gas.
- Trends in capital costs for generation technologies. These impact the long-run marginal cost (LRMC) of generation, a key indicator for long term capacity expansion.

Jacobs used PSR's suite of market modelling tools to develop a generation expansion plan dispatch, simulated across 90 historical hydro sequences to capture the uncertainty and interactions driven by variability in hydro inflows and wind and solar profiles.

Capacity Expansion

OptGen by PSR is a long-term generation and interconnection planning model that determines an optimal expansion plan under uncertainty.

OptGen decomposes the planning problem into two components: investment and operation. The Investment Module uses capital and fixed operation cost data along with generalized constraints to reflect policies and guidelines (e.g., emissions reductions targets, firm energy, or capacity targets) and uses an estimate of operating costs provided by the Operation Module. This integration with SDDP ensures that the expansion plans must consider the same uncertainties that are visible to the dispatch model.

Market Simulation

SDDP by PSR is the world-leading commercial implementation of the Stochastic Dual Dynamic Programming algorithm integrated with a sophisticated mathematical simulation model.

The SDDP algorithm was developed to assess optimal water dispatch policies ("future cost functions") in electricity markets with large amounts of hydro-electric supply. The problem formulation in such markets is fundamentally different to a more typical thermal-dominated system due to the importance of the opportunity value of stored energy and the uncertainty associated with hydrological inflows.

The future cost function provides an expected "cost-to-go" between some point in time and the end of the study horizon as function of storage levels. This provides a water value to be used in the market simulation as the objective function of the minimization is expanded to include minimizing the sum of the immediate costs (e.g., fuel) and future costs (i.e., the value return by the future cost function given the final storage after the decision is made).

The impact of hydrological inflows on nodal prices is diverse and non-linear, making it essential that many inflow years are sampled with the appropriate inter-temporal correlation and correlation between reservoir inflows and wind and solar resource availability. Our NZEM SDDP model is trained on 75 synthetically constructed inflow sequences to avoid 'over-fitting' the policy to historical data and final simulations use all available historical inflow data (1932 to 2021, 90 for simulations). Each simulation begins with a different historical hydro year and follows that sequence until it reaches the end of historical data (2021 inflows), which point it 'carousels' to the beginning of the historical dataset (1932).

Expected nodal electricity prices and the distribution of prices across the 90 inflow sequence simulations are produced as output, calculated either on marginal cost bids.

Jacobs' current SDDP model is updated with all Jacobs' base input assumptions, including all the load, wind and solar traces, AC and DC network information, accumulated from a variety of data-sources. Generation expansion is provided by OptGen outputs.

Jacobs has developed projected load traces for each node of the model based on publicly available historical demand profiles and based the relevant Transpower's demand projection for each connection point. This results in a more nuanced projection of demand, that considers local factors. Jacobs has also developed a

[1]method to assign to each node rooftop PV, small-scale storage, DER, and demand side participation resources.

Renewable profiles

Times Series Lab (TSL) by PSR is a renewable resource modelling tool that retrieves historical trace data for variable renewable energy (VRE) source and develop synthetic traces that are appropriate correlated spatially and temporally with hydro inflows.

TSL extracts historical data from the MERRA-2 global reanalysis database, which can then be calibrated using actual generation data and converted into wind or solar farm production by specifying turbine/panel type, hub-height, tracking behaviour, and other characteristics.

[1] The historical trace data referred to here is hourly wind and solar resource data retrieved from the ERA5 database of satellite data

4. Assumptions

This section outlines the key assumptions underpinning our analysis of distributed solar uptake scenarios in New Zealand. These assumptions form the foundation of our modelling approach and are critical to interpreting the study's results. We have carefully considered various factors including technological advancements, economic projections, regulatory environments, and consumer behavior patterns. While every effort has been made to ensure these assumptions are as accurate and realistic as possible, it is important to note that they represent our best estimates based on current information and trends. The following subsections detail our assumptions across different aspects of the electricity market and solar technology adoption, providing context for the scenarios modelled and the outcomes observed.

Jacobs's models a base case scenario on assumptions based on publicly available data, augmented with Jacobs' market expertise and experience.

Table 1 presents the assumptions associated with the Base Case and the applicable data sources.

Table 1. Base case scenario assumptions

Assumption	Source
Demand – underlying demand	Adapted from Electricity Demand and Generation Scenarios Environmental Case[2]
Demand – transport electrification	Adapted from Electricity Demand and Generation Scenarios Environmental Case
Demand – process heat electrification	Adapted from Electricity Demand and Generation Scenarios Environmental Case
Demand – data centres	Adapted from Electricity Demand and Generation Scenarios Environmental Case
Demand - NZAS	Tiwai Point aluminium smelter remains throughout the modelling horizon
Rooftop solar	Adapted from Electricity Demand and Generation Scenarios Environmental Case
Generation candidate stack	Adapted from Ministry of Business Innovation, and Employment's 2020 Generation stacks and augmented with Transpower's connection request queue and the Electricity Authority's generation pipeline data.
Technology costs	Adapted from NREL ATB 2024 benchmarked against New Zealand costs[4]
Transmission Investment	Grid backbone (including HVDC) upgraded as indicated in:
	- Transpower's Net Zero Grid Pathways[5]

[2] We use the EDGS Environmental scenario as the medium-to-long-term trajectory with some adjustments to align with the most recently observed demand data and to ensure that the modelled embedded generation is consistent with Jacobs models

	- Waikato and Upper North Island Voltage Management[6]
	- Upper South Island Upgrade project[7]
Committed generation	Drawn from Electricity Authority's Generation Investment Pipeline[8]
WACC	8.5% real, pre-tax

Aggregate electricity demand growth utilised in Jacobs' modelling is illustrated in Figure 3, below.

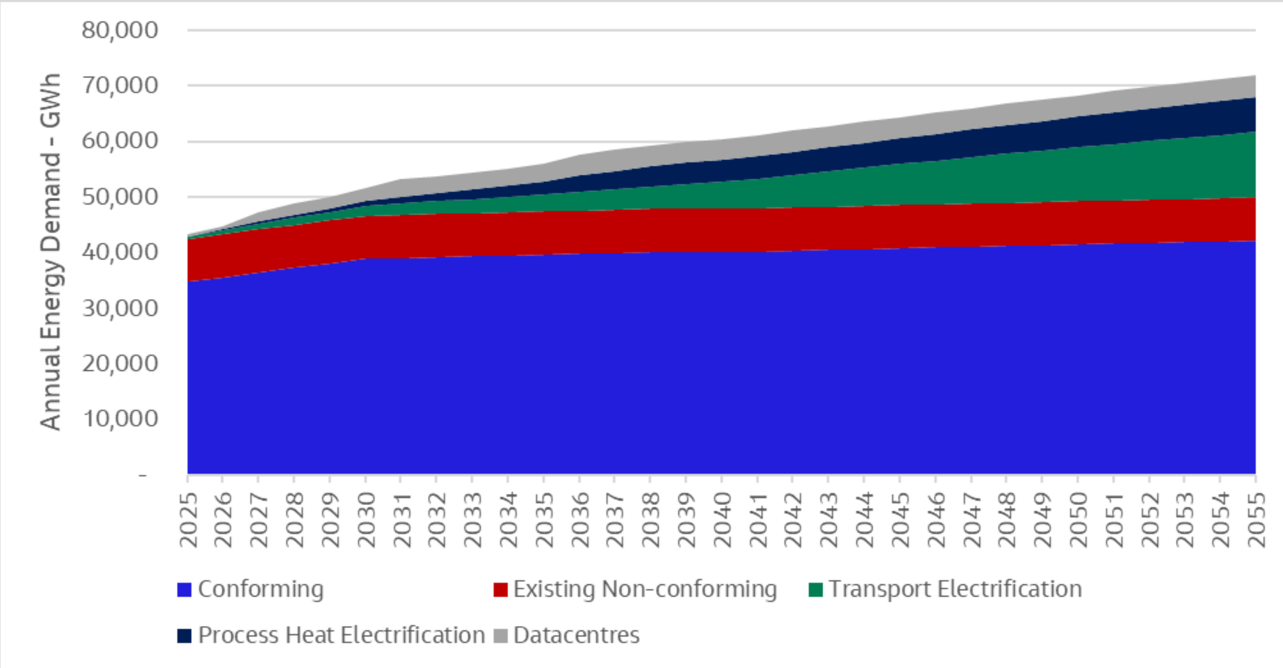


Figure 3. Demand projections[3]

Non-utility solar and BESS assumptions

The Jacobs Base Case reflects our central view of distributed solar and BESS uptake, aligning broadly with current trends and policies.

The other two cases modelled have non-utility solar and BESS uptake provided by Rewiring Aotearoa. Rewiring Aotearoa Case 1 (RA1) incorporates more ambitious adoption rates provided by Rewiring Aotearoa. Rewiring Aotearoa Case 2 (RA2) presents a third view in which the non-utility solar and BESS penetration by the end of the modelling horizon is similar to RA1, but the uptake rate is reduced to avoid extended the periods of surplus supply seen in our RA1 outcomes.

In all cases, non-utility solar and BESS uptake was modelled as a fixed input assumption, with OptGen building additional grid-scale supply as necessary to achieve an economically efficient build schedule. The model was not given the option of making economic retirements of existing plants but existing coal and gas

[3] "Conforming" and "non-conforming" demand is consistent with Electricity Authority's definition of GXPs (https://www.ea.govt.nz/industry/wholesale/spot-market/about-conforming-and-non-conforming-exit-points/). Conforming demand is typically a large number of small customers (e.g. residential/commercial/small industrial) behind a single GXP that allows for statistical forecasting. Non-conforming demand is typically a single or small number of customers behind a single GXP (typically large industrial users).

plants were forced to retire at their expected end-of-life in all cases. In the case of Rewiring Case 1, existing thermal baseload retirements was brought forward to 2030 due to very low utilisation and revenue inadequacy in initial results.

The following details outline the specific assumptions for non-utility solar capacity, generation profiles, and associated BESS deployment for each case. These assumptions form the foundation of our analysis and are crucial for understanding the divergent outcomes observed across the scenarios.

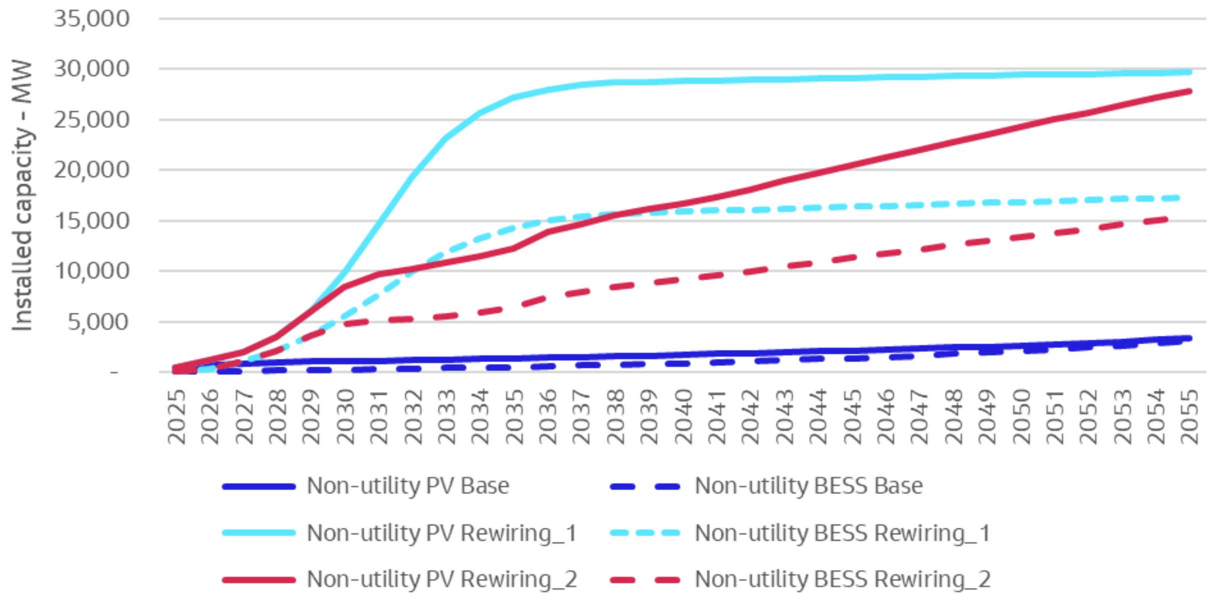


Figure 4. Non-utility solar and BESS assumptions by case

It is important to acknowledge that the equilibrium between electricity supply and demand can be achieved through various mechanisms, including increasing demand, reducing supply, or a combination of both. This study primarily focuses on supply-side dynamics, particularly the impact of distributed solar uptake. However, we recognize that there are likely significant social, environmental, and economic benefits to accelerating the electrification of New Zealand's broader energy sector, which could substantially increase electricity demand.

While exploring multiple demand sensitivities and conducting a whole-of-energy system optimization would provide valuable insights, these analyses were beyond the scope of this study. Such comprehensive assessments would require consideration of factors like electric vehicle adoption rates, industrial process electrification, and changes in building energy use patterns. These elements, along with their interactions with distributed energy resources, could significantly influence the optimal path forward for New Zealand's energy transition.

We emphasize that the findings presented here should be considered within the context of these limitations. Future studies incorporating broader demand scenarios and whole-system optimization approaches would complement this analysis, providing a more comprehensive picture of New Zealand's energy future and the role of distributed solar within it.

5. Outcomes

This section presents the key findings of our analysis, comparing the outcomes across the three modelled scenarios: Jacobs Base Case, Rewiring Aotearoa Case 1, and Rewiring Aotearoa Case 2. We focus on four critical metrics that provide insight into the potential impacts of increased distributed solar uptake on New Zealand's electricity market. These metrics are:

1. Time-weighted average prices
2. Generation-weighted average prices
3. Generation expansion requirements
4. Total supply-side system cost

By examining these factors, we aim to provide insight into how different levels of distributed solar adoption could influence market dynamics, infrastructure needs, and overall system costs. The following subsections detail our findings for each metric, offering comparisons between the scenarios and insights into the potential implications for New Zealand's energy future. These results form the basis for our conclusions and policy recommendations presented later in this report

5.1 Capacity Expansion

This section presents the modelling results related to grid-scale generation expansion across the three scenarios examined: Jacobs Base Case, Rewiring Aotearoa Case 1, and Rewiring Aotearoa Case 2. The analysis of grid-scale generation expansion is crucial for understanding how different levels of distributed solar uptake might influence the need for centralized power generation infrastructure in New Zealand.

Our modelling considers the interplay between increased distributed solar capacity and the requirements for utility-scale generation. We examine how the timing, scale, and type of grid-scale generation investments may shift in response to varying levels of non-utility solar deployment. This analysis provides insights into potential changes in the generation mix, the pace of renewable energy adoption at the utility scale, and the overall evolution of New Zealand's electricity supply infrastructure.

The following subsections detail our findings, comparing the projected grid-scale generation expansion across the three scenarios. We focus on key aspects such as:

1. Total installed capacity changes over time
2. Shifts in the mix of generation technologies
3. Timing of new generation investments
4. Potential deferred or avoided grid-scale projects

Figure 5. Capacity Expansion – Base case

, Figure 6, and Figure 7 show the generation capacity changes by technology from 2025 to 2055.

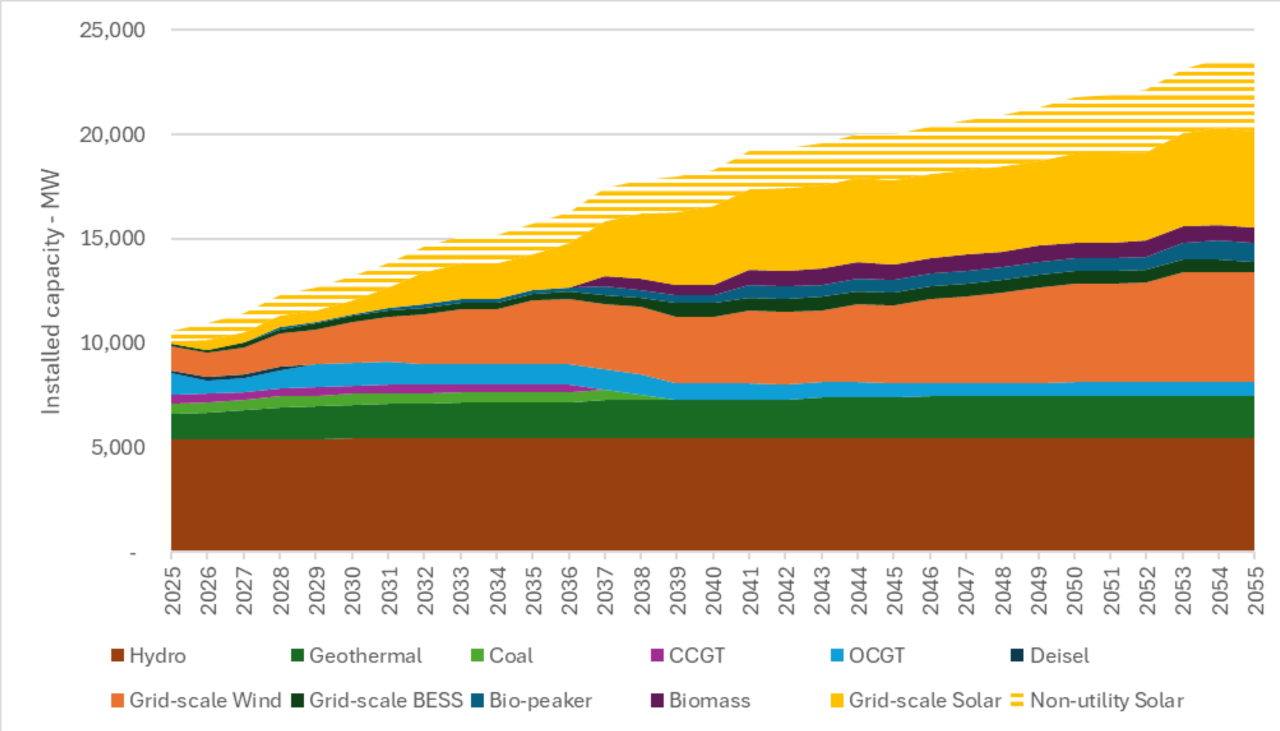


Figure 5. Capacity Expansion – Base case

The Base Case builds grid-scale wind and grid-scale solar in similar quantities and complements the new VRE with new peaking plant for firm capacity. The diversity across wind and solar is driven by the model capturing the impact of increased correlated VRE capacity on generation-weighted average prices, leading the model to switch between technologies according to which has the highest net benefit at the time.

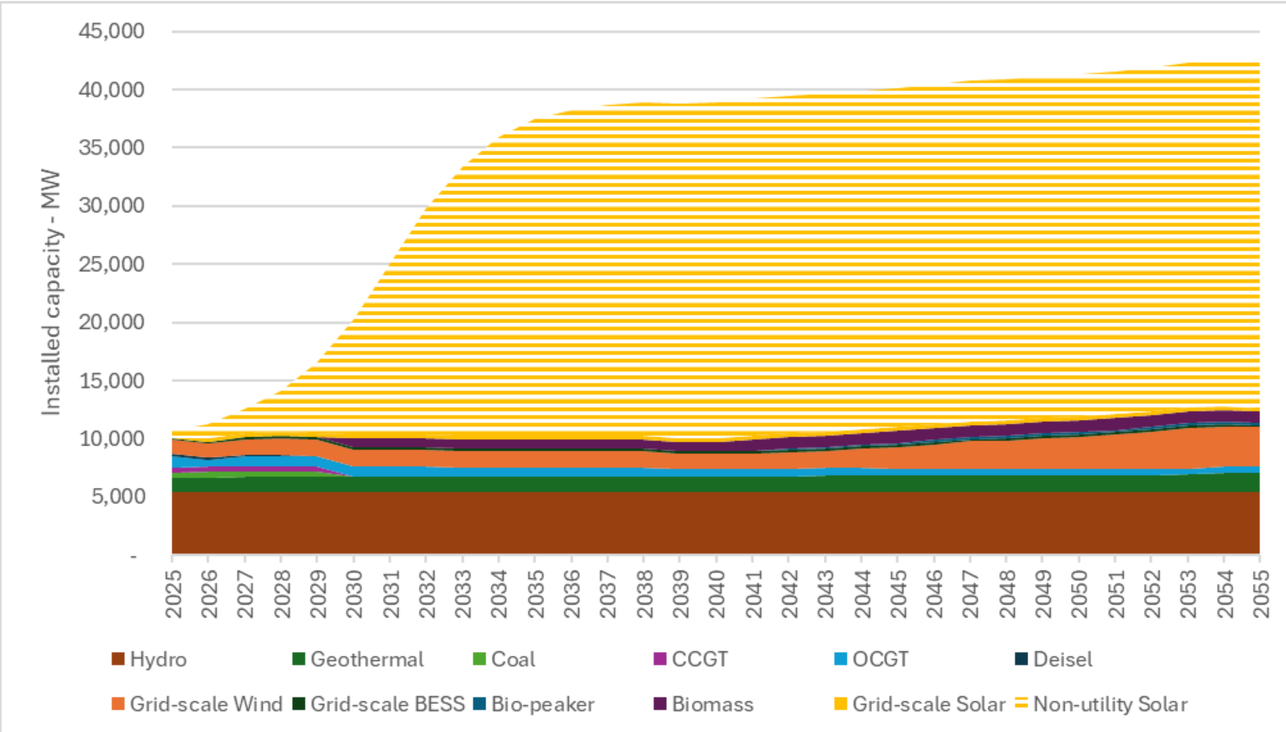


Figure 6. Capacity Expansion – Rewiring Aotearoa Case 1

In both Rewiring Aotearoa cases, there are extended periods of time when no new grid-scale VRE is built due to the supply provided by the non-utility solar. Rewiring Aotearoa Case 1 (above) builds its first uncommitted grid-scale wind farm in 2044, and Rewiring Aotearoa Case 2 (below) builds it in 2036. Neither case builds any new grid-scale solar due to the impact of the non-utility solar on the generation-weighted average price and the likelihood of market curtailment.

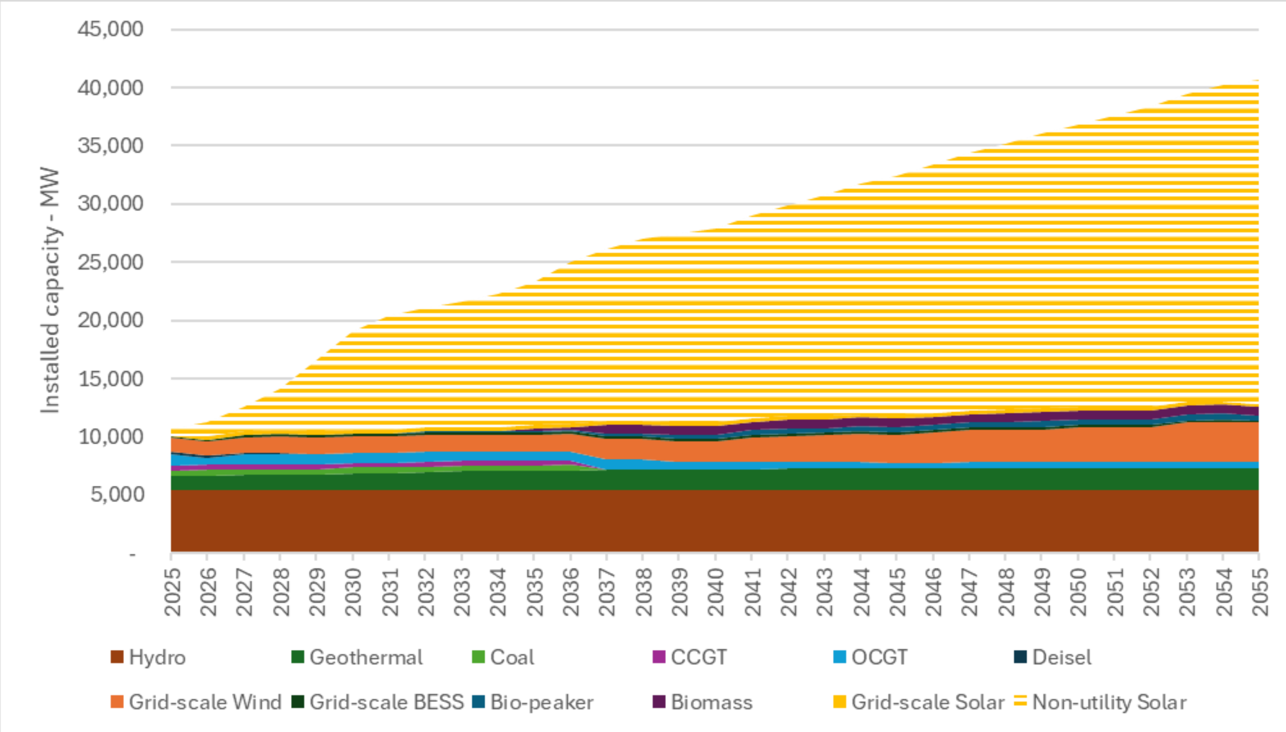


Figure 7. Capacity Expansion – Rewiring Aotearoa Case 2

5.2 Generation by technology

Generation by technology largely follows similar trends to capacity by technology, except:

- Generation figures capture the impact of expected capacity factor, for example wind in New Zealand tends to generate 40%+ of its maximum potential, whereas grid-scale solar tends to generate closer to 21% of its potential.
- Generation figures also capture the impact of generation curtailment, e.g. periods of time when there is more supply than demand or a net network constraint means that generation is reduced.

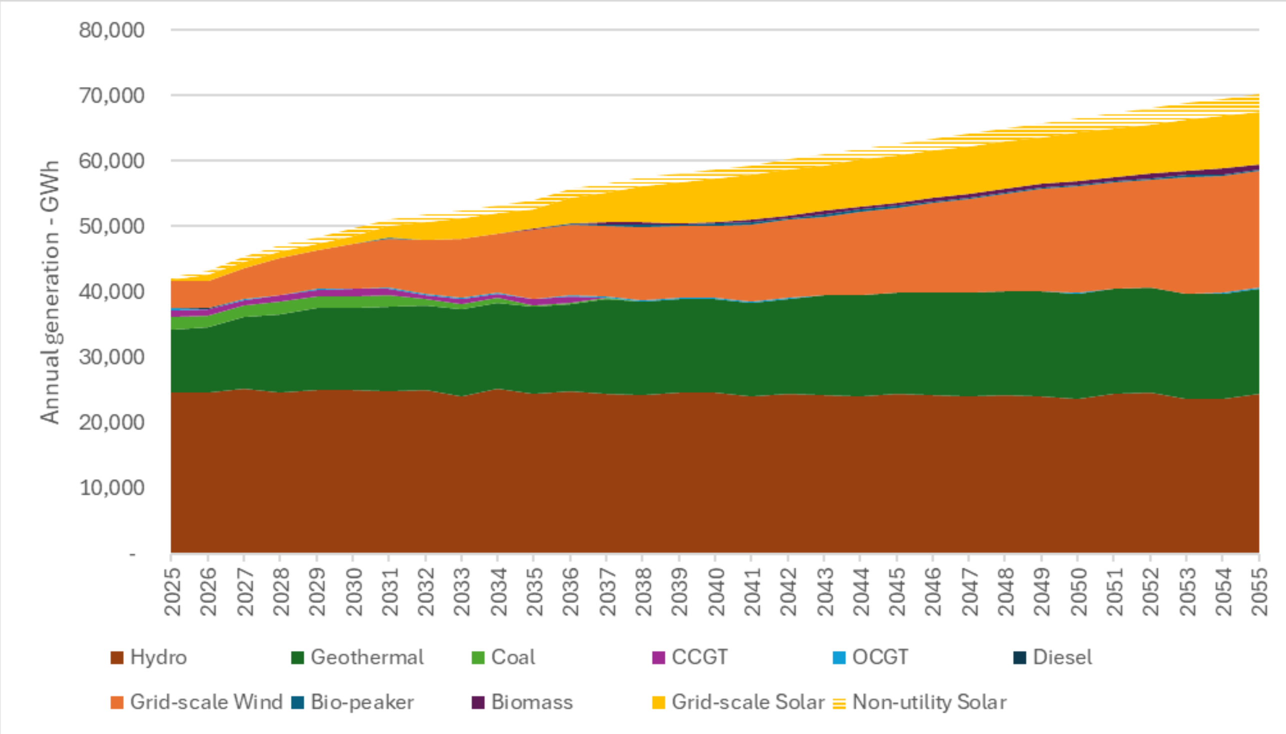


Figure 8. Generation by technology – Base Case

The Base Case, as with capacity, has a diversity of new supply across wind and solar (including non-utility solar). We see a slight downward trend in hydro generation and hydro takes on a greater role in firming VRE and for dry events.

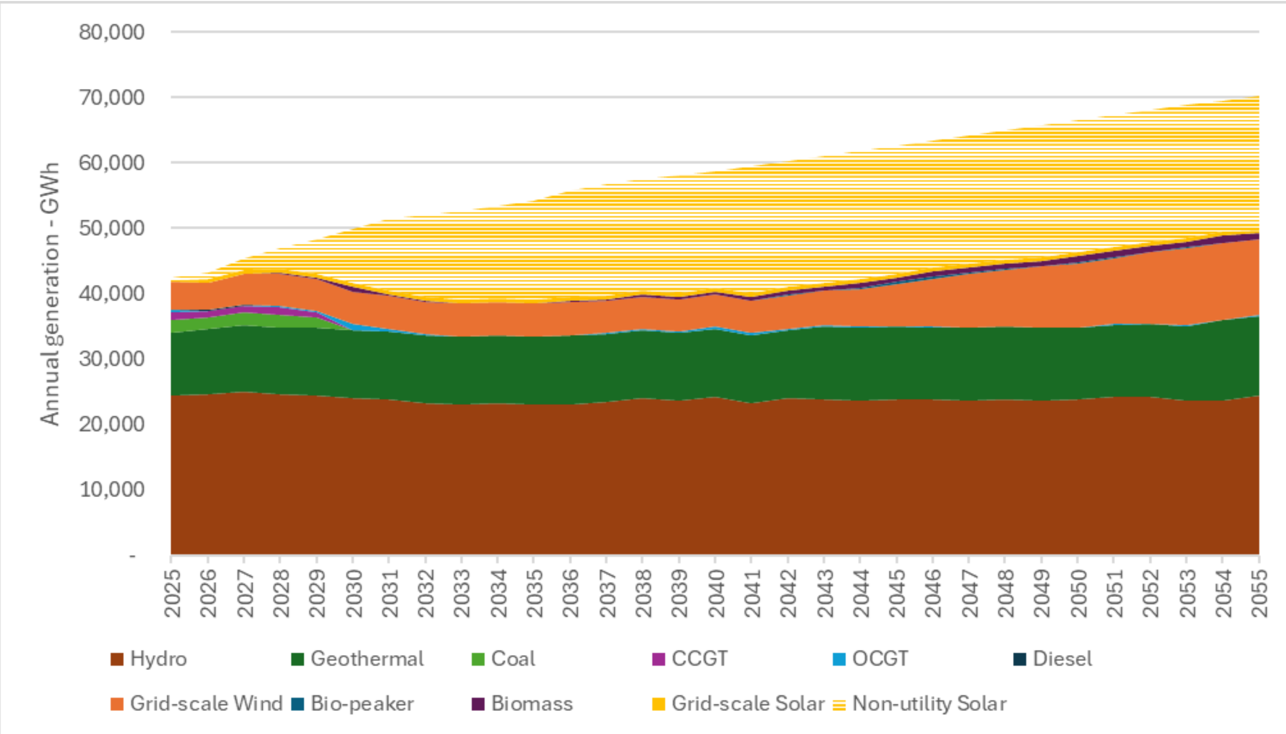


Figure 9. Generation by technology – Rewiring Aotearoa Case 1

In Rewiring Aotearoa 2, we see the rapid uptake of non-utility solar push out thermals by 2030 and grid-based generation reduce slightly more markedly than the Base Case. It is only as non-utility solar growth slows in the early 2040s while load continues to grow that wind generation begins to grow. At its highest point, the percentage of annual energy contributed by non-utility solar is approximately 30%.

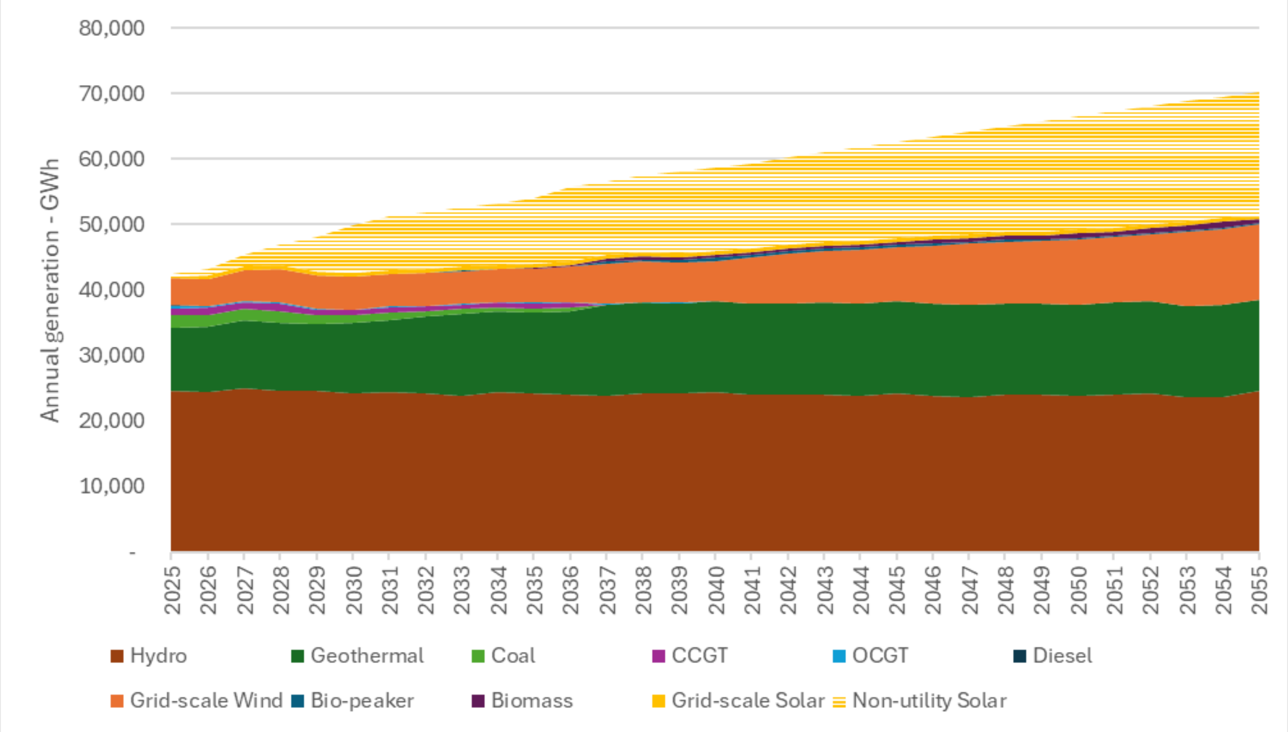


Figure 10. Generation by technology – Rewiring Aotearoa Case 2

Rewiring Case 2 is slightly moderated relatively to Rewiring Case 1. Existing thermal generation stays until the mid-2030s, like the Base Case and wind generation begins to grow at a similar time. In percentage terms, the highest contribution in this case is at the end of the modelling horizon and is approximately 26%.

5.3 Prices

This section presents the modelling results related to electricity spot market prices across the three scenarios: Jacobs Base Case, Rewiring Aotearoa Case 1, and Rewiring Aotearoa Case 2. Understanding the potential impacts of increased distributed solar uptake on electricity prices is crucial for policymakers, market participants, and consumers alike.

Our analysis focuses on two key price metrics:

1. Time-Weighted Average Prices (TWAP): This metric represents the average price of electricity over a given period, with each price point weighted equally regardless of the volume of electricity traded. TWAP provides insight into the overall price trends and is particularly relevant for consumers who pay retail rates based on time-of-use tariffs.

2. Generation-Weighted Average Prices (GWAP): This metric calculates the average price weighted by the volume of electricity generated at each price point. GWAP is especially important for generators as it reflects the revenue they can expect to receive for their output, accounting for variations in generation volumes during different price conditions.

By examining both TWAP and GWAP, we can gain a comprehensive understanding of how distributed solar uptake might affect different stakeholders in the electricity market. The following subsections detail our findings, comparing these price metrics across the three scenarios and over time. We analyze how increased distributed solar generation influences:

- Overall price levels
- Seasonal and daily price patterns
- Price volatility
- Differences between TWAP and GWAP, indicating potential market dynamics shifts

Time-weighted average prices

Analysis of the modelling results reveals a notable trend in annual average time-weighted average prices (TWAP) across the scenarios.

In cases with higher levels of distributed solar and BESS penetration, these prices tend to be suppressed compared to the Base Case. This suppression effect is primarily due to the reduced requirement for grid-scale generation, as a significant portion of demand is met by distributed resources, particularly during peak solar production hours.

However, we note that while average annual prices may be lower, the inter-seasonal price variation becomes markedly more pronounced in these high-penetration scenarios. The market tends to experience oversupply conditions during summer months, leading to very low prices, while winter periods see tighter energy supply, resulting in significantly higher prices. This increased seasonal price volatility reflects the challenges of balancing supply and demand in a system heavily reliant on seasonal renewable resources, highlighting the need for careful consideration of energy storage and demand management strategies to mitigate extreme price fluctuations.

Figure 11, Figure 12, and Figure 13 show box and whisker blots for time-weighted average prices in each of the three cases.

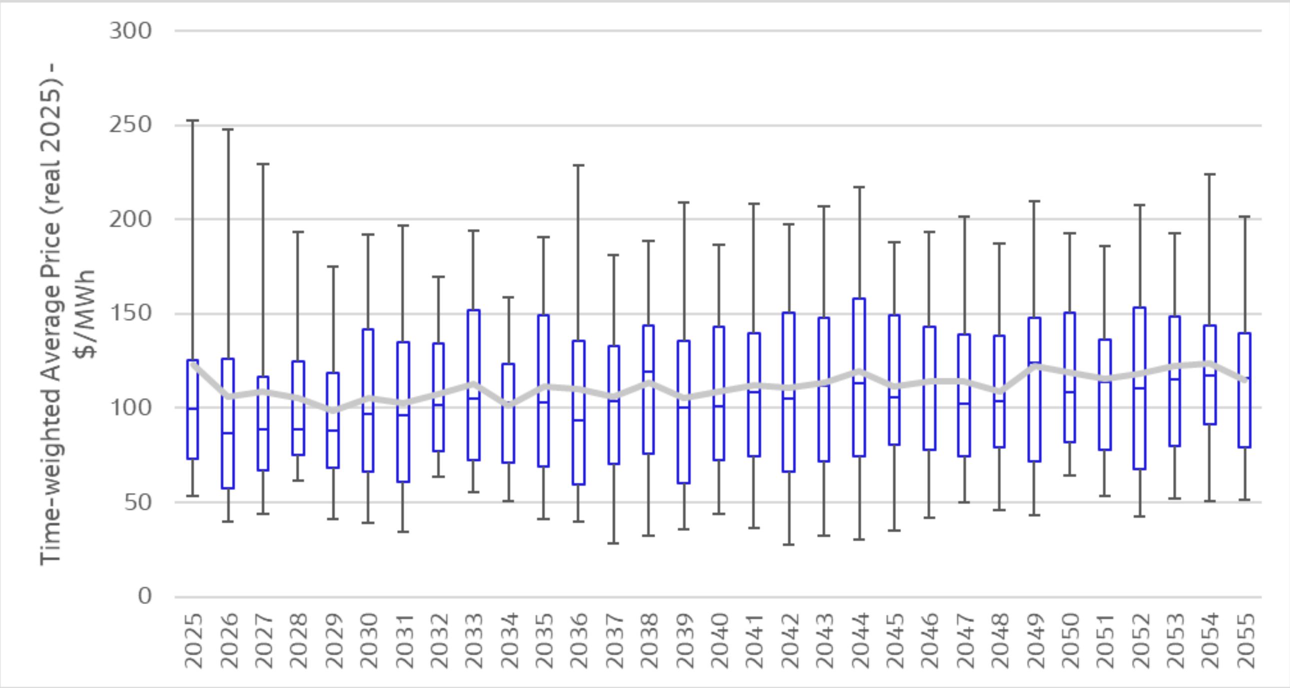


Figure 11. Time-weighted average price – Base Case

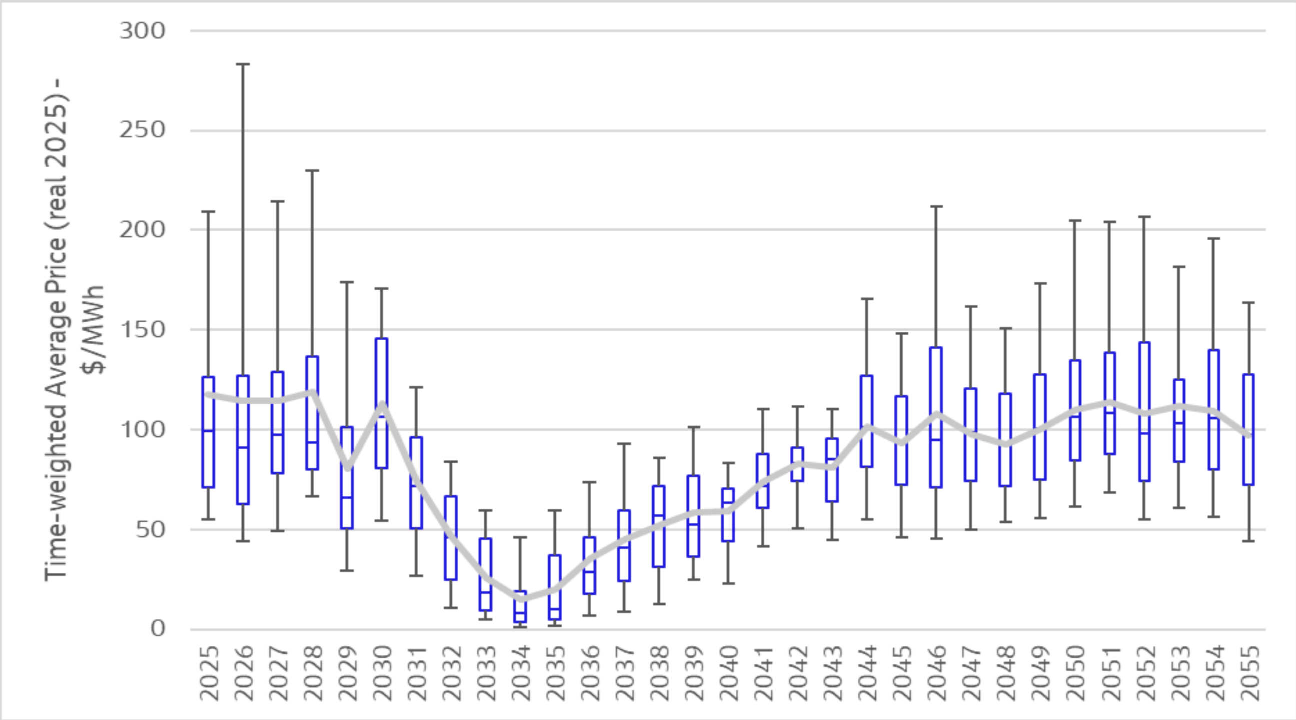


Figure 12. Time-weighted average price – Rewiring Aotearoa Case 1

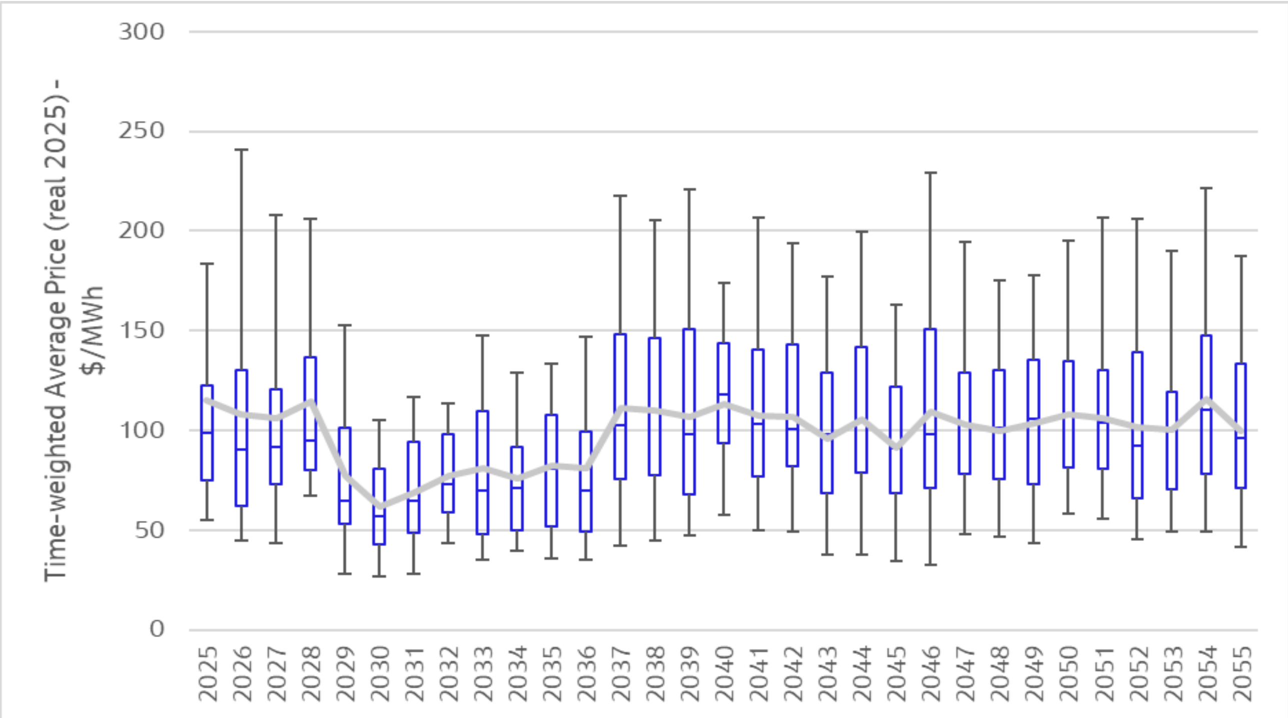


Figure 13. Time-weighted average price – Rewiring Aotearoa Case 2

In this analysis, the additional non-utility solar in the two Rewiring Aotearoa cases brings down annual average prices by $10/MWh to $15/MWh in the long term but slightly increases price volatility over winter due to the heavy reliance on solar resource. During periods of low insolation and high demand, the Base Case has more wind and geothermal generation at its disposal before it is required to call on expensive thermal generation.

These price graphs also demonstrate the impact of the periods of time where the non-utility solar assumptions in the Rewiring Aotearoa Cases – in particularly Rewiring Aotearoa Case 1 – result in an imbalance between supply and demand. In this study, we did not allow the model to bring forward new demand, for example electrification of process heat or transport to take advantage of these sustained periods of low prices. As result, the system appears "over-supplied" until demand catches up.

A valuable consideration of future work would be to understand the implications of this outcome if non-utility solar uptake were to reach the levels assumed in these scenarios, for example:

- does this imply a capacity payment is needed for some existing plant, to ensure that they remain financially viable through the transition?
- Could new load be brought forward to "re-balance" supply and demand?
- What is the whole-energy-system/whole-of-economy/social benefit of increasing the rate of electrification on the energy system?

Figure 14 shows the weekly time-weighted average prices for each scenario in 2050, as an example of the increasing seasonal variability driven by higher solar penetration.

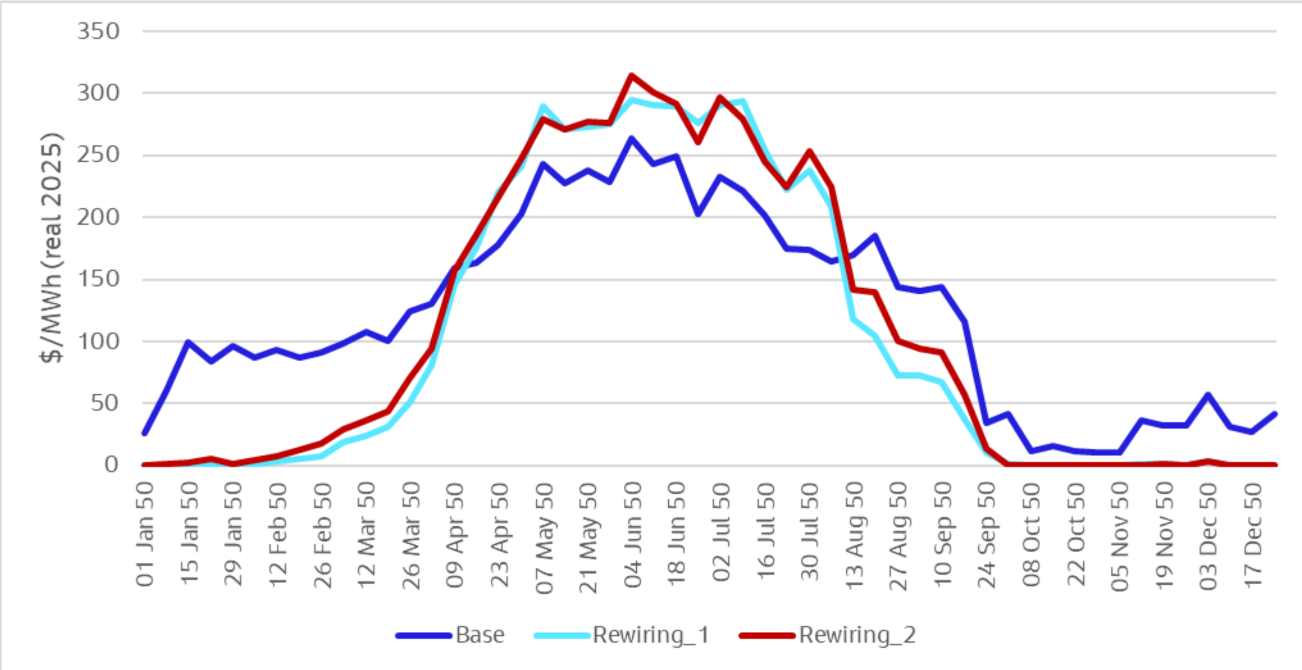


Figure 14. Weekly average prices by scenario in 2050

The graph above shows prices dropping to zero – or very close to zero – from early October through early February as the spring melt fills the lakes, insolation increases, and demand naturally declines post-winter. Conversely, prices increase to about $300/MWh on a weekly average basis over winter. These prices include the impact of moving all planned maintenance of generation plants to spring and summer to maximise capacity over winter.

In addition to average weekly prices being higher over winter in the Rewiring Aotearoa Cases, the high-side risk (the prices during periods of shortage) is greater. The graph below shows the weekly prices average across the most expensive 5% of inflow sequences for the week over the winter months.

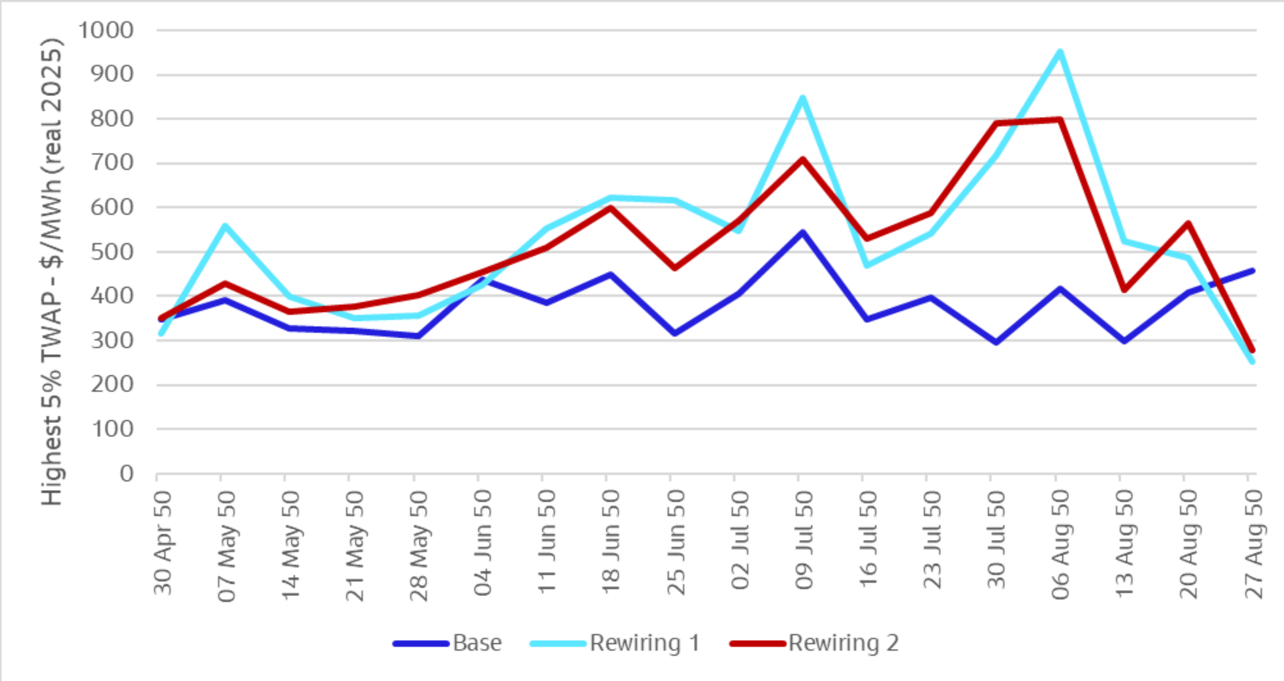


Figure 15. Winter weekly average prices in most expensive inflow sequences - 2050

We note the Rewiring Aotearoa Cases are impacted by weeks of high prices in some inflow sequences that are several hundred dollars more than the Base case over winter. This helps to illustrate that while average annual prices are brought down by surplus energy over summer, the reduced diversity in the Rewiring Aotearoa Cases increases the risk of shortage over winter.

Generation-weighted average prices by technology

The analysis of generation-weighted average prices (GWAP) in scenarios with very high rooftop solar penetration reveals significant implications for market dynamics and generator revenues. In these high-penetration cases, we observe several key trends:

1. Overall GWAP Reduction: Generally, the GWAP tends to decrease compared to the Base Case, particularly for thermal and baseload generators. This reduction is primarily due to the displacement of higher-cost generation during peak solar production hours.
2. Increased Volatility: While average prices may be lower, GWAP exhibits greater volatility, with more extreme highs and lows throughout the year.
3. Seasonal Disparities: The seasonal variation in GWAP becomes more pronounced. Summer GWAPs are significantly depressed due to abundant solar generation, while winter GWAPs appear to spike due to lower solar output and higher demand.
4. Technology-Specific Impacts: Different generation technologies experience varied effects:
    - Solar generators – grid-scale and non-utility solar – see a marked decrease in their GWAP due to high correlation in output times.
    - Flexible generators (e.g., fast-start gas plants) achieve higher GWAPs as they capture price spikes during periods of low solar output.
    - Baseload generators face challenges, receiving lower average prices during their continuous operation.

5. Evening Price Peaks: A shift in daily price patterns emerge, with evening peaks becoming more pronounced as solar generation drops off.

6. Reduced Correlation with Demand: The traditional correlation between high demand and high prices weakens, as peak demand periods coincide with high solar output.

These GWAP dynamics have important implications for generator profitability, investment signals, and overall market structure. They suggest a need for generators to adapt their operational strategies and for market mechanisms to evolve to ensure system reliability and investment adequacy in a high solar penetration scenario. The findings underscore the complexity of transitioning to a highly distributed, renewable-dominated electricity system and the importance of carefully managing this transition to maintain market efficiency and security of supply.

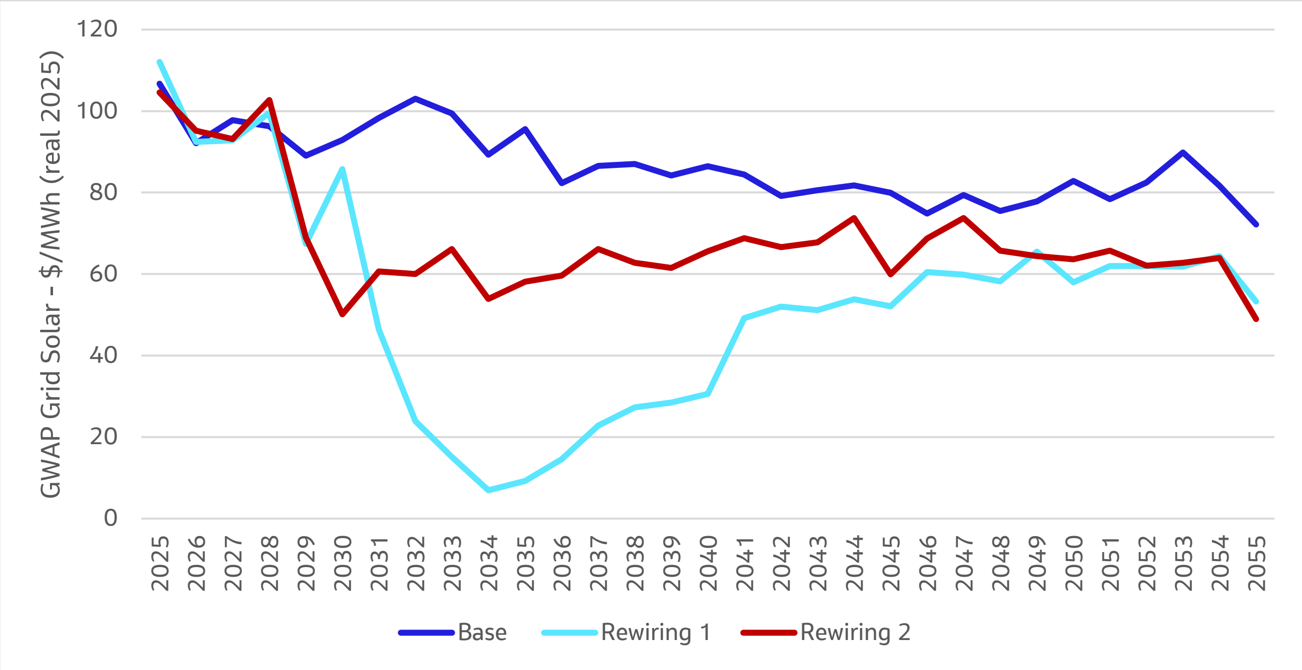


Figure 16. Annual GWAP – Grid-scale solar

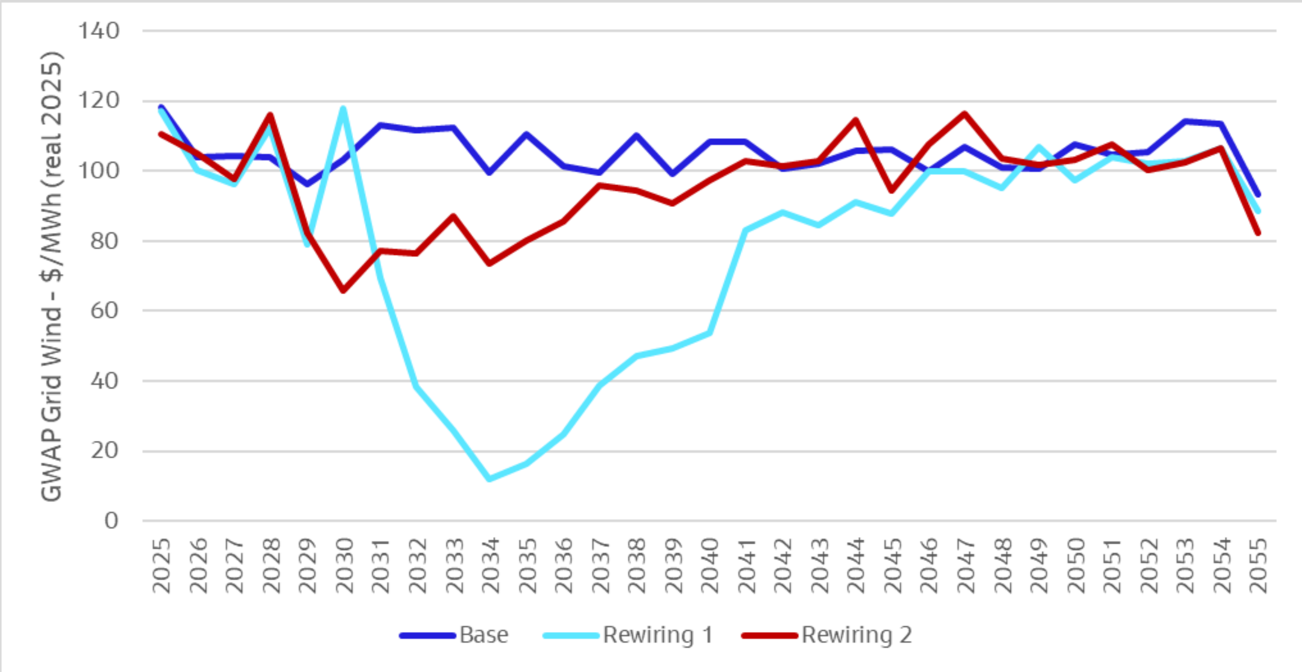


Figure 17. Annual GWAP – Land-based Wind

5.4 System supply costs

This section presents the modelling results related to total supply-side system costs across the three scenarios: Jacobs Base Case, Rewiring Aotearoa Case 1, and Rewiring Aotearoa Case 2. Understanding the potential impacts of increased distributed solar uptake on overall system costs is crucial for assessing the economic implications of different energy pathways.

Our analysis of supply-side system costs encompasses four primary components:

1. Capital Costs: Investments required for new generation capacity and upgrades to existing facilities, including the cost of non-utility solar and BESS[4].
2. Fuel Costs: Expenses associated with fuel consumption for thermal generation.
3. Carbon Costs: Costs related to carbon emissions, reflecting potential carbon pricing or emissions trading schemes.
4. Load Curtailment Costs: Economic impact of any necessary load shedding during peak demand or supply shortages.

It is important to note that this analysis does not include costs associated with network augmentation or expansion. Consequently, the figures presented here can be interpreted as reflecting the network investment savings required for the higher distributed solar cases to become the "system least cost" option. In other words, if network costs in higher solar cases are lower than in the Base Case by an amount greater than or equal to the cost differential shown in this analysis, then those cases would represent a more economically efficient pathway.

The following subsections detail our findings, comparing total supply-side system costs and their components across the three scenarios over time. We analyze how increased distributed solar generation influences:

[4] All capital cost assumptions for non-utility solar and BESS were provided by Rewiring Aotearoa and are presented in Appendix B.

- Overall system costs
- The balance between capital, fuel, carbon, and curtailment costs
- Potential cost savings or additional expenses in different areas of the electricity system

These results provide insight into the economic trade-offs associated with various levels of distributed solar adoption in New Zealand's electricity system, while highlighting the importance of considering network costs in future, more comprehensive analyses.

Figure 18 and Figure 19 show the total present value supply-side system costs in each of the cases.

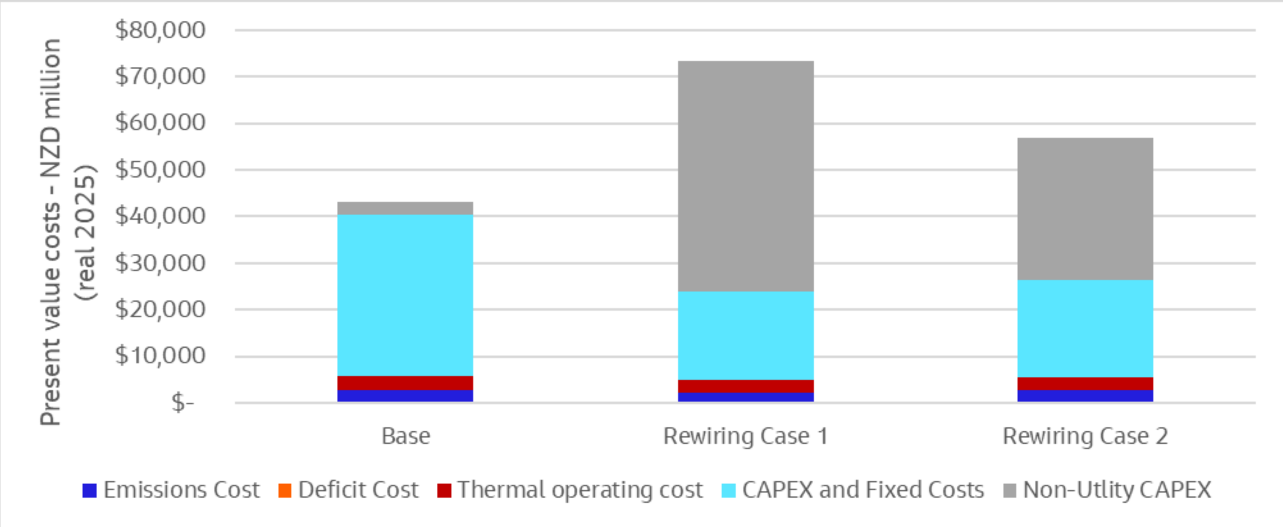


Figure 18. Present value system supply costs

The total system supply costs in the Base Case are $43b, compared to $73b for Rewiring Aotearoa Case 1 and $57b for Rewiring Aotearoa Case 2[5]. These differences ($30b for RA1 and $14b for RA2) provide a reference point for further studies, e.g. if comparable savings exist in transmission and network investment that could offset the additional supply cost, then RA1 and/or RA2 could be reasonably expected to deliver the lowest delivered cost of electricity given this demand scenario.

The additional cost in the two higher non-utility solar cases stems from two sources:

- MWh for MWh, the capital cost of non-utility solar tends to be higher than that of grid-scale solar. Therefore, one MW of additional non-utility solar pushes out less than 1 MW of grid-scale solar
- The magnitude of the uptake means that the non-utility solar is also replacing non-solar generation that is built in the Base Case. This results in some relatively low LCOE (e.g. geothermal, the cheaper end of the wind stack) being removed along with some diversity amongst the VRE, leading to market curtailment.

[5] see Appendix C for tabulated figures

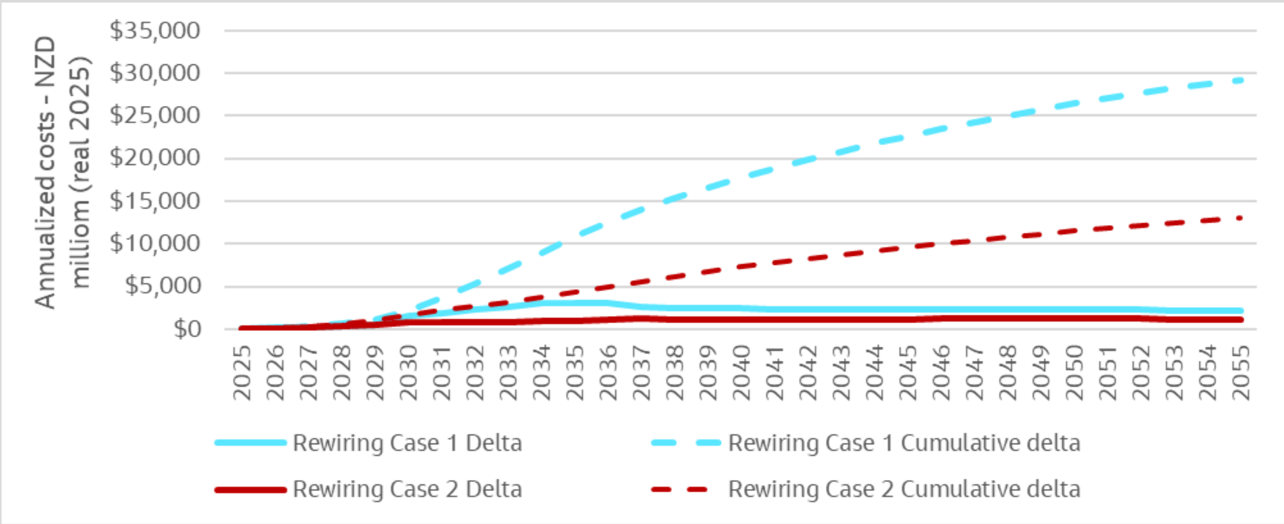


Figure 19. Annualised system cost differences relative to Base Case

5.5 Spilled Energy

This section presents the modelling results related to energy spillage across three scenarios: Jacobs Base Case, Rewiring Aotearoa Case 1, and Rewiring Aotearoa Case 2 energy spillage, also known as curtailment, refers to the reduction or restriction of energy production from available resources. Understanding the patterns and extent of energy spillage is crucial for assessing the efficiency and challenges of integrating high levels of distributed solar and other variable renewable energy (VRE) sources into the electricity system.

Energy curtailment can occur under various circumstances:

1. Market Excess: When total generation exceeds demand, and there is insufficient storage or export capacity.
2. High Correlation between VRE Sources: When multiple renewable sources (e.g., solar and wind) produce simultaneously at high levels, potentially exceeding system needs.
3. Transmission Constraints: When local generation exceeds the capacity of transmission infrastructure to distribute the energy.
4. Operational Constraints: When system stability requirements limit the amount of variable generation that can be integrated at a given time.

It is important to note that energy curtailment is a common and often necessary feature in electricity markets with high penetrations of variable renewable energy. It is not inherently undesirable or uneconomic, as it can play a role in maintaining system stability and reliability. However, very large amounts of spill from particular technologies can indicate diminishing returns on investment, as less production is available to cover the initial capital costs. Significant curtailment may also suggest that the market value of additional capacity from that resource is decreasing.

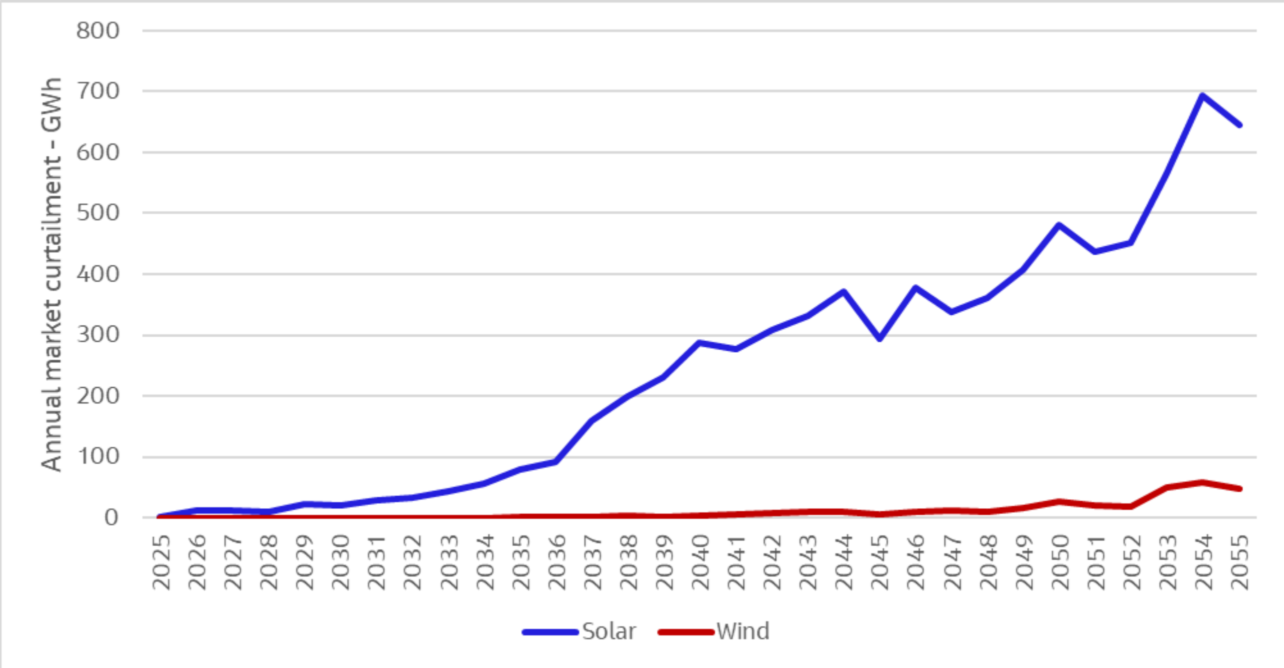


Figure 20. Annual VRE market curtailment – Base case

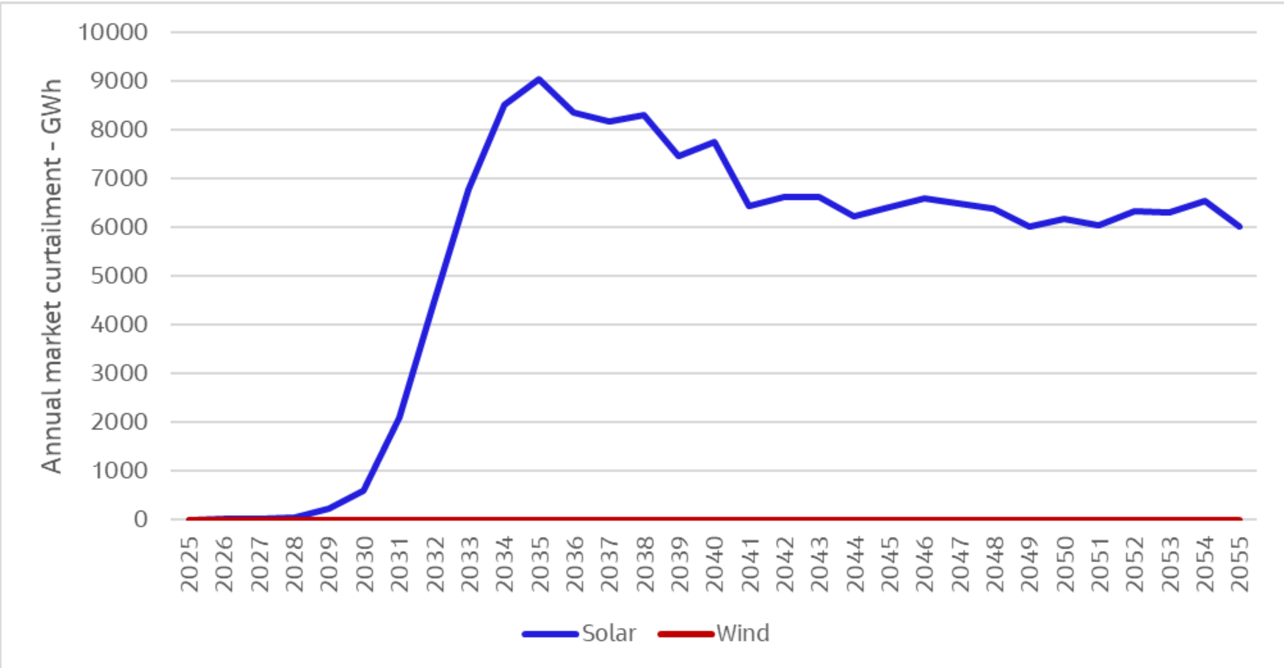


Figure 21. Annual VRE market curtailment – Rewiring Aotearoa Case 1

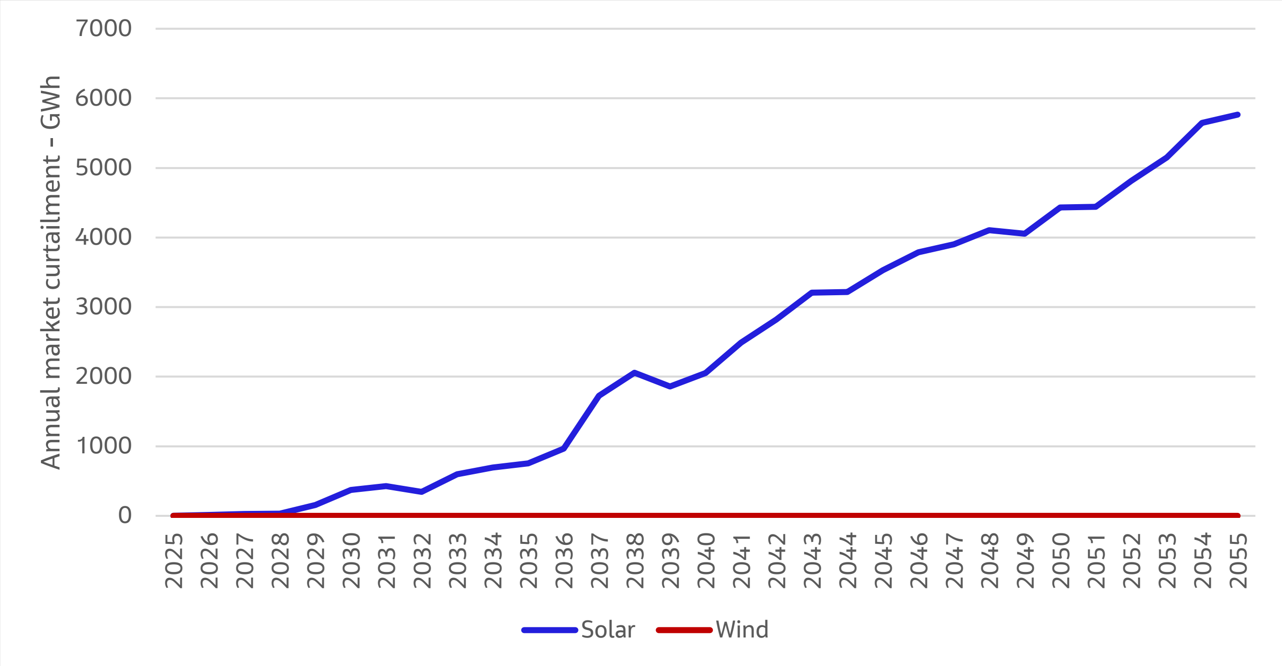


Figure 22. Annual VRE market curtailment – Rewiring Aotearoa Case 2

Energy spillage reaches 6 TWh per year in both the Rewiring Aotearoa Cases compared to 700 GWh per year in the Base cases, in both cases dominated by spill pf solar energy. The trajectory of the spill figures in the two Rewiring Aotearoa Cases illustrate the difference between indexing the solar growth to demand growth rather than using the original Rewiring trajectory, but in both cases, the spill by the end of the modelling horizon is relatively similar.

Wind spill drops to essentially zero in the two Rewiring Aotearoa Cases due to the lower installed wind capacity due to reduced investment in grid supply and an assumption that non-utility generation is preferentially spilled before grid-scale generation which is often bid into the market as "must-run" as it is often financed through PPAs that require it to be dispatched.

A note on relative storage

The New Zealand hydro system has a relatively small amount of storage capacity given its importance to the energy system. In total there is approximately 4.5 TWh of controllable storage – including contingent storage – and a generating capacity of over 5 GW meaning there is about six weeks storage capacity in the lakes. This limits the degree to which hydro operators can conserve for the long term without risking spilling inefficiently.

In addition, there are orders of magnitude difference between the storage capacity that can be reasonably expected from a fleet of BESS (distributed and/or grid-scale) and that which would be required for to move a material amount of surplus solar generation from summer to winter.

For example, this study finds that annual solar spill settles at about 6 TWh in the two high-uptake cases. A reasonable question is "why can't all the BESS move that to winter and avoid those high thermal costs". But the 14 GW of distributed BESS assumed in those scenarios is still only 56 GWh of storage (assuming a four-hour BESS) or a little less than 1% of the spilled energy over summer.

As shown in the following section, the Rewiring Aotearoa Cases start winter full reservoirs even in relatively dry conditions, so the capacity for storing more surplus energy over summer is being used, but it is not enough to avoid the curtailment figures seen in the charts above. The system would require additional storage in the order of several terawatt-hours to materially reduce the spilled energy in the Rewiring cases. For scale context, one terawatt-hour is equivalent to approximately 70 million large residential BESS installations or five thousand grid-scale installations equivalent to the Ruakaka BESS.

While the Rewiring cases start winter with higher lake levels than the Base case, that additional stored water is needed due to the reduced diversity of supply and low solar output over winter. By mid-July or August, lake levels tend to be lower in the Rewiring Aotearoa Cases than the Base case (see Figure 23), resulting in potential security of supply issues.

5.6 Reservoir levels

This section examines the relationship between hydro lake levels and electricity spot market dynamics in New Zealand's hydro-dominated electricity system. Understanding this relationship is fundamental to interpreting the broader impacts of increased distributed solar penetration on market behavior and system reliability.

New Zealand's electricity system is unusual in its heavy reliance on hydroelectric generation, which typically accounts for 55%-60% of the country's total electricity production. This dependence on hydro resources means that lake levels play a pivotal role in shaping spot market prices, generation patterns, and overall system security.

Key aspects of this hydro-market dynamic include:

1. Price Sensitivity: Spot prices are highly responsive to changes in lake levels, with lower levels generally corresponding to higher prices due to the perceived scarcity of the resource.
2. Seasonal Patterns: Lake levels typically follow seasonal patterns, influencing intra-year price variations and generation strategies.
3. Risk Management: Market participants closely monitor lake levels as a key indicator for future price trends and potential supply constraints.
4. Long-term Planning: Hydro storage levels influence decisions about thermal generation dispatch and overall system planning.
5. Security of Supply: During dry years or periods of low inflows, lake levels become critical in ensuring the security of electricity supply across the country.

In the context of increasing distributed solar penetration, it is important to understand how these new energy sources interact with and potentially alter the traditional hydro-driven market dynamics. In particular, as thermal firming becomes more expensive due to gas supply shortages and carbon price increases, the risk associated with running out of water increases substantially leading to higher opportunity cost of generation in the months leading up to winter. Similarly, as hydro is expected to play a firming role for greater penetration of VRE, the value of having hydro capacity at the ready increases.

As a result of these dynamics, all scenarios see a tendency to hold lake levels higher in the lead up to winter relative to the current policy. This leads to slightly lower levels of hydro generation and greater spill as a trade-off for increasing security.

However, this change is substantially more pronounced in the cases with a greater uptake of distributed solar and BESS for three reasons:

1. There is a surplus of solar energy over spring and summer meaning that hydro generators spend more time at their minimum flow, giving lakes the opportunity to fill
2. There is a greater risk of shortage over winter due to the heavy reliance on solar and low solar resource over winter
3. There is very little value in keeping water in the lakes in the lead-up to spring because the combination of spring melt, spring wind, spring sunshine, and decreasing demand mean that the lakes will likely have a lot of opportunity to fill up before the following winter. So, water conserved before spring has a higher probability of being spilt.

The net effect of these dynamics is that the system starts winter with more energy stored in the lakes when there are large volumes of solar in the supply stack – as has been hypothesized by advocates of high non-utility solar uptake – *but it needs to start winter higher due to supply being dominated by solar and therefore storage is lower over winter*.

This point illustrates a material limitation when considering large changes to one part of the electricity market, e.g. large amount of additional non-utility solar, without considering the impact of those changes on the rest of the system. In particular, the assumption that the rest of the market is static will not hold for any length of time. The market would over time respond and find a new equilibrium that accommodates the additional solar supply by reducing investment in other new supply and – potentially – retiring existing supply unless extra-market arrangements were made.

The market response can, of course, come from a combination of supply-side and demand-side changes. For example, energy surplus – and therefore low prices – over summer is likely to provide incentives for loads to find ways to maximize summer load and minimize winter load or incentivize greater electrification of industries that are naturally summer-weighted, such as farming and dairy. This would improve seasonal alignment between supply and demand but would erode the surplus energy and therefore the argument that additional solar leads to higher lake levels at the beginning of winter.

It is important to note that this modelling was undertaken to explore the implications of Rewiring Aotearoa's projected scenario of a high solar uptake (28 GW) by 2050 on the wholesale market. The observed results therefore are relative to that scenario and do not reflect an optimised future investment path, which would likely have different outcomes.

The graphs below provide insight into how we would expect the market to respond to the changing risk conditions under each scenario by presenting 2050 stored hydro energy in each case from three perspectives:

- Mean: Weekly stored energy averaged across all inflow sequences.
- Highest 5% - Weekly stored energy averaged across the 5% of inflow sequences with the highest stored energy in the week. This view indicates how the system stores energy when it is plentiful.
- Lowest 5% - Weekly stored energy averaged across the 5% of inflow sequences with the lowest stored energy in the week. This view indicates how the system stores energy when it is scarce.

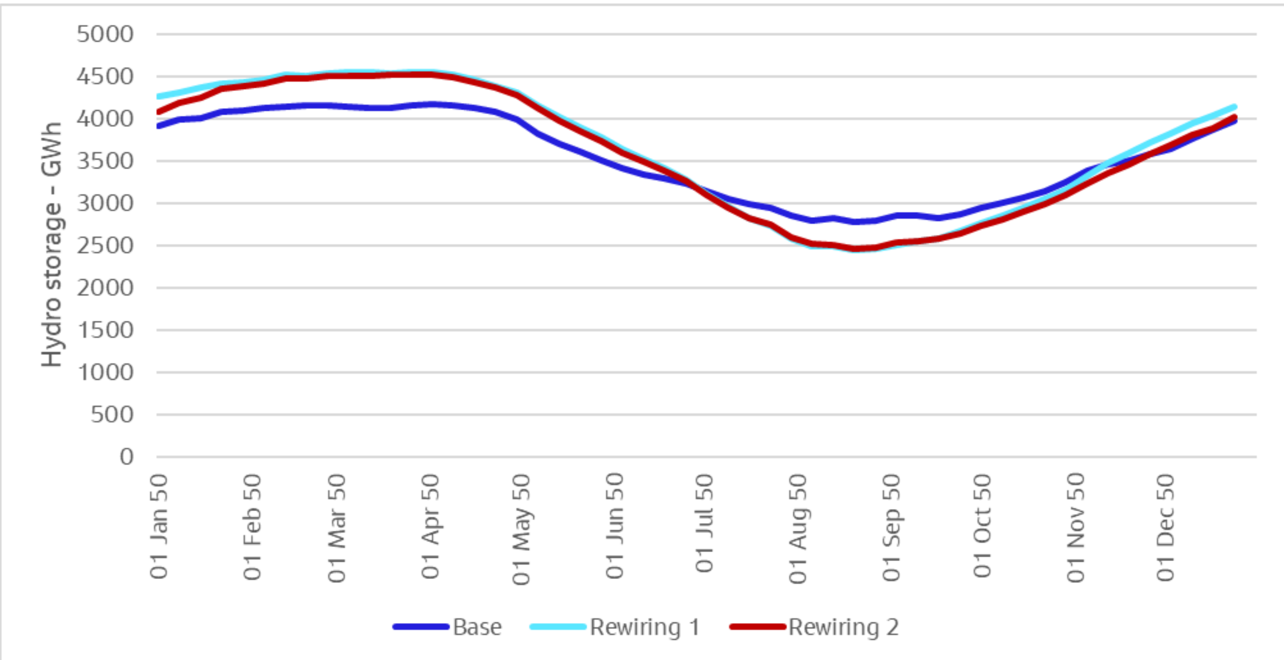


Figure 23. Weekly stored hydro energy in 2050 - Mean

The chart above shows the Base Case maintaining flatter reservoir levels throughout the year compared to the Rewiring Aotearoa Cases on average. The Rewiring Aotearoa Cases use surplus solar energy over summer to ensure that lakes are full by the beginning of winter and then use the additional energy to compensate for low solar output during the winter period. As less non-solar capacity has been built, the Rewiring Aotearoa Cases draw more water from the lakes over winter and by July-August lake levels are – on average – lower in the Rewiring Aotearoa Cases than in the Base case.

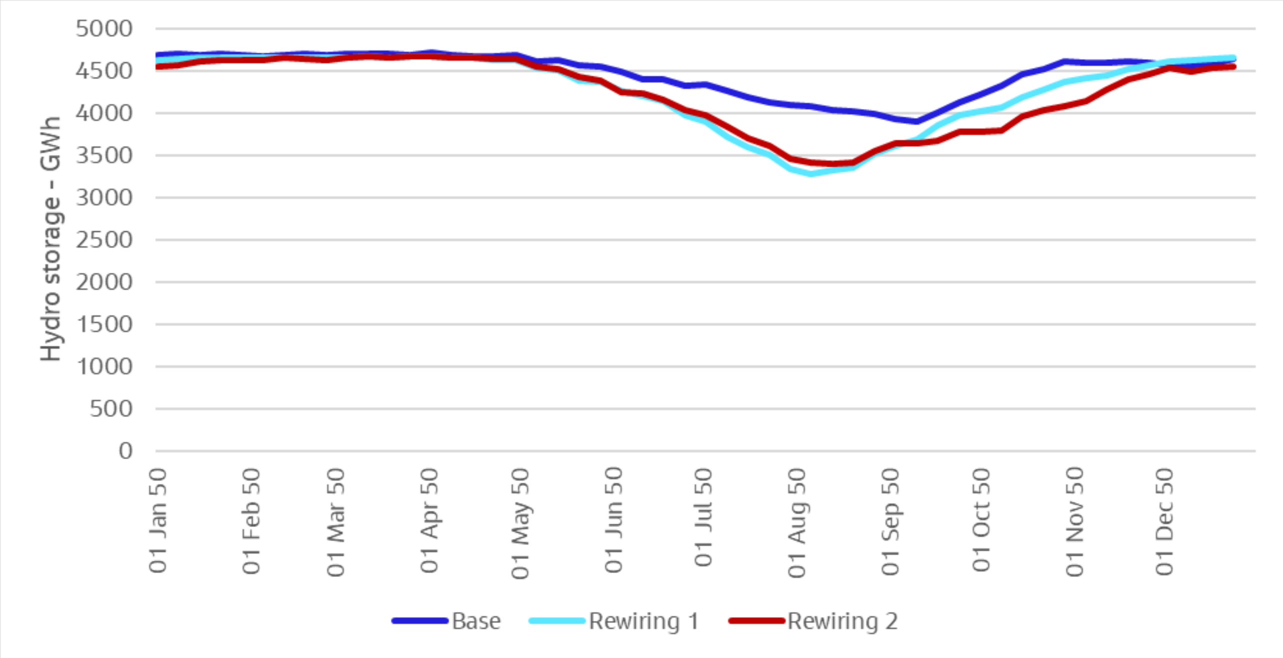


Figure 24. Weekly stored hydro energy – Highest 5%

The chart above shows the weekly stored energy average across the inflow sequences with the highest 5% of stored energy, i.e. sequence where energy has been plentiful leading up to that week. In this view, the primary difference between the scenarios is in winter and spring, when the Base Case retains more stored energy due to having more firm energy over winter. By the end of the year, the reservoirs are full in all cases in these high-energy inflow sequences.

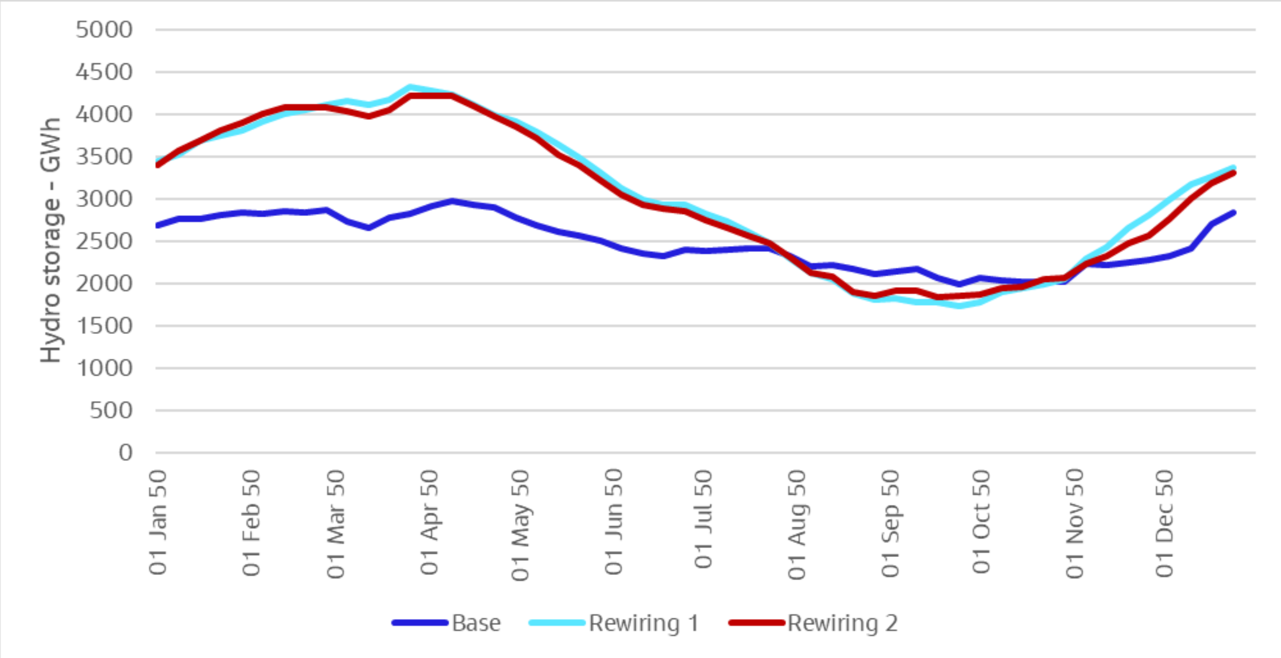


Figure 25. Weekly stored hydro energy – Lowest 5%

The final chart in this series shows the weekly stored energy in sequences with the lowest 5% of stored energy in the week, i.e. sequence where energy has been scarce in the lead up to given week. The Rewiring Aotearoa Cases can fill the reservoirs even in these sequences indicating that they are starting winter in a very similar state in most inflow sequences. Between the beginning of winter and the beginning of spring, however, the Rewiring Aotearoa Cases draw down lake levels by about 1 TWh more than the Base case, meaning that September lake levels are about 500 GWh less in the Rewiring Aotearoa Cases than the Base case.

5.7 Transmission flows

This section presents outcomes related to changes in transmission flows across the scenarios and illustrates an area where increasing distributed solar and BESS has the potential to offset some of the higher supply costs.

Our modelling includes all circuits and nodes in the transmission grid, so we can determine grid flows at each point in time across all hydro sequences modelled.

The graphs below are flow duration curves, i.e. the percentage of time – over all hydro sequences – that flow on the inter-region corridor is modelled to be above a given level. In all cases, a positive flow indicates flow from south to north and negative flow indicates flow from north to south.

The impact on inter-regional flows varies markedly across regions, depending on how much of the distributed solar is allocated to the region and alternative generation available. The most impacted transmission corridor is between the central North Island and the upper North Island, due to the large amount of residential solar allocated to the Auckland region and the limited alternative generation available in the upper North Island. Conversely, the impact on flows from the lower North Island to central North Island is relatively muted due to the prevalence of two-way flow and the strong wind resource in the area that the solar displaces.

Outcomes presented here are for 2040, chosen because it is a year when the difference between the two Rewiring Aotearoa Cases is large, providing more diversity across the results.

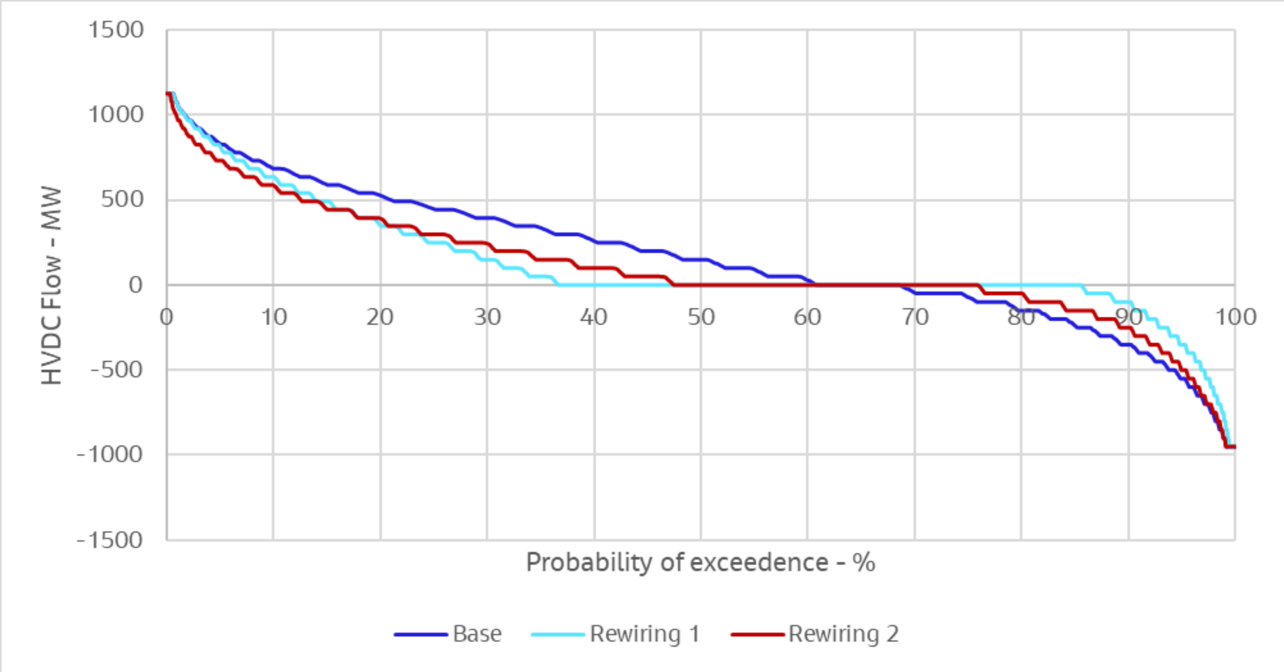


Figure 26. HVDC flow duration curve - 2040

Note the high incidence of "zero" flow on the HVDC in the two Rewiring Aotearoa Cases. This indicates increasing incidences of each island being self-sufficient, leaving HVDC transfer unnecessary. Maximum north and south flows, however, remain similar across all cases.

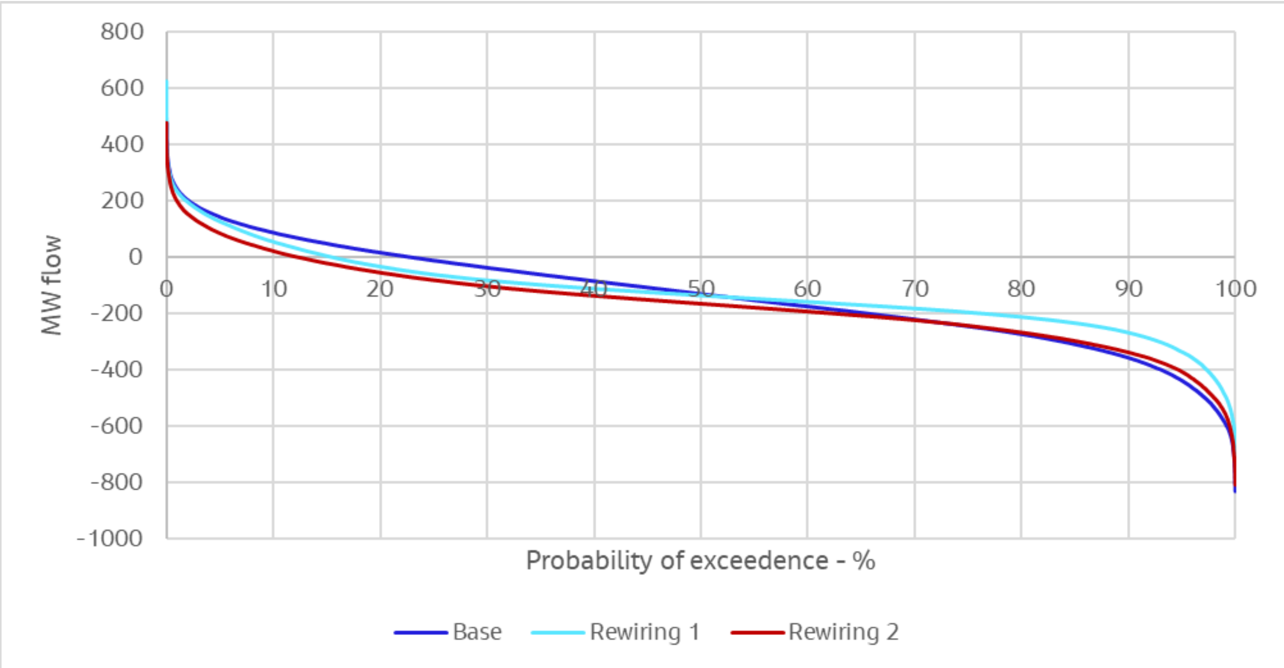
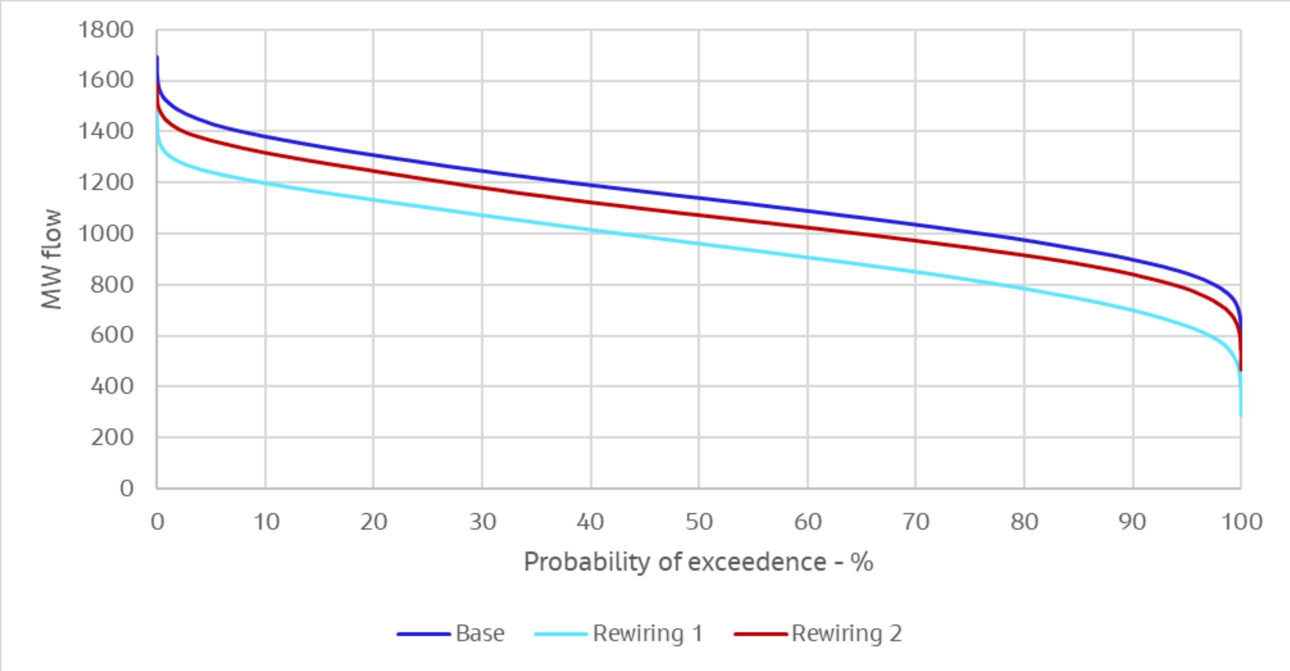


Figure 27. Lower North Island to Central North Island Flow Duration Curve - 2040

Lower North Island to central North Island flows are slightly reduced in the Rewiring Aotearoa Cases, but probably not enough to impact transmission investment materially.

Figure 28. Central North Island to Upper North Island Flow Duration Curve – 2040



The central North Island to upper North Island transmission corridor appears to offer the greatest potential for transmission benefit from uptake of distributed solar and BESS due to both one-way flow from south to north, the high numbers of potential installations in Auckland, and the limited generation capacity expansion in the area.

6. Conclusions

This study examined three scenarios of distributed solar and battery uptake in New Zealand: the Jacobs Base Case (reaching 3.5 GW nationally by 2055) and two cases based on Rewiring Aotearoa's projections (achieving approximately 28 GW of distributed solar at different rates). The analysis reveals several key findings:

1. Both Rewiring Aotearoa Cases show signs of over-supply, particularly the case with faster uptake, given the fixed demand assumptions used.
2. In the more rapid uptake scenario (Rewiring 1), existing renewable and thermal generation face financial strain, potentially requiring support until demand growth and spot price recovery occur.
3. Higher distributed solar uptake replaces all new renewable build, not just grid-scale solar, until the mid-2030s or mid-2040s, depending on the scenario. This results in reduced supply diversity, with wind and geothermal development delayed or deferred beyond the end of the study horizon.
4. The increased reliance on solar leads to greater seasonal price swings and higher volatility, indicating potential challenges for security of supply. In particular, the risk of winter shortage increases in the higher solar cases due to reduced supply diversity and low solar output during the high demand period.
5. Supply-side costs in both Rewiring Aotearoa Cases are substantially higher than the Base Case ($30b and $14b in the Rewiring 1 and Rewiring 2 cases, respectively), primarily due to the higher capital cost per MWh of small-scale generation compared to grid-scale alternatives, and increased energy spill.
6. The impact on inter-regional transmission requirements is likely to be greatest between the central North Island and upper North Island.

The additional supply-side costs in the Rewiring Aotearoa Cases can be viewed as the savings that would need to be realised in other parts of the system - most likely in transmission and distribution costs - for these higher solar uptake scenarios to potentially deliver a lower overall cost of electricity compared to the Base Case. We understand that estimating these savings is part of a parallel workstream.

If the distribution and transmission savings are not enough to offset the additional supply costs, this should not be taken as a rejection of distributed solar or BESS in general, which offer significant potential value to the system. Rather, this would indicate that the higher solar uptake scenarios modelled here may be beyond a tipping point where benefits begin to diminish and the impacts of reduced supply diversity increase in the context of the demand scenario modelled, and further investigation into lower levels of penetration would be valuable.

7. Next steps

Based on the findings of this study, we recommend the following steps to further enhance our understanding of the impact of distributed solar on impact on New Zealand's energy system:

1. Transmission and Distribution Network Savings Analysis: Conduct a comprehensive study to estimate potential savings in transmission and distribution network costs associated with increased non-utility solar and Battery Energy Storage Systems (BESS) uptake. This analysis should identify potential tipping points where significant cost reductions may occur.

2. Tipping Point Assessment to investigate critical thresholds in distributed solar and BESS adoption that could lead to substantial changes in network infrastructure requirements and associated costs.

3. Whole-of-energy system modelling: based on steps above, undertake whole-of-energy-system modelling to assess establish an optimal path forward for New Zealand’s energy system to inform policy and regulation development, and market design.

By pursuing these next steps, we can develop a more comprehensive understanding of the role distributed solar and BESS can play in shaping a cost-effective, resilient, and low-carbon energy future for New Zealand.

Appendix A. Jacobs Market Modelling toolkit

A.1 SDDP

SDDP by PSR is the world-leading commercial implementation of the Stochastic Dual Dynamic Programming algorithm integrated with a sophisticated mathematical simulation model.

The SDDP algorithm was developed to assess optimal water dispatch policies ("future cost functions") in electricity markets with large amounts of hydro-electric supply. The problem formulation in such markets is fundamentally different to a more typical thermal-dominated system due to the importance of the opportunity value of stored energy and the uncertainty associated with hydrological inflows.

The future cost function provides an expected "cost-to-go" between some point in time and the end of the study horizon as function of storage levels. This provides a water value to be used in the market simulation as the objective function of the minimisation is expanded to include minimising the sum of the immediate costs (e.g. fuel) and future costs (i.e., the value return by the future cost function given the final storage after the decision is made).

Figure 29. SDDP Future Cost Function

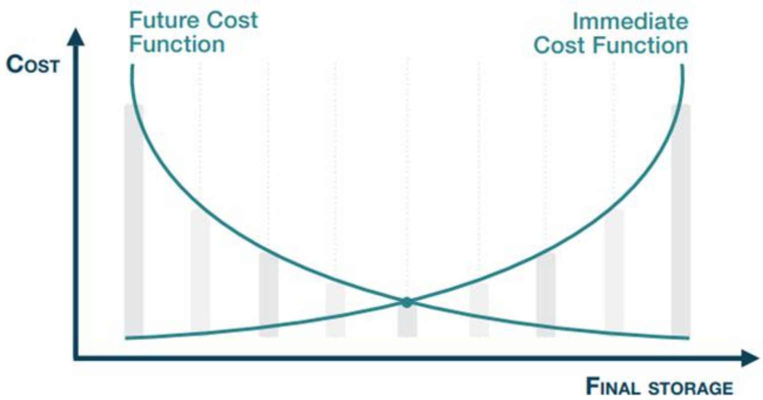


Figure A-30. SDDP schematic

The impact of hydrological inflows on nodal prices is diverse and non-linear, making it essential that many inflow years are sampled with the appropriate inter-temporal correlation and correlation between reservoir inflows and wind and solar resource availability. Our NZEM SDDP model is trained on 75 synthetically constructed inflow sequences to avoid 'over-fitting' the policy to historical data and final simulations use all available historical inflow data (1932 to 2021, 90 for simulations). Each simulation begins with a different historical hydro year and follows that sequence until it reaches the end of historical data (2021 inflows), which point it 'carousels' to the beginning of the historical dataset (1932).

Expected nodal electricity prices and the distribution of prices across the 90 inflow sequence simulations are produced as output, calculated either on marginal cost bids.

Jacobs' current SDDP model is updated with all Jacobs' base input assumptions, including all the load, wind and solar traces, AC and DC network information, accumulated from a variety of data sources. Generation expansion is provided by OptGen outputs.

Jacobs has developed projected load traces for each node of the model based on publicly available historical demand profiles and based on the relevant Transpower's demand projection for each connection point. This results in a more nuanced projection of demand that considers local factors. Jacobs has also developed a method to assign to each node rooftop PV, small-scale storage, DER, and demand side participation resources.

A.2 OptGen

OptGen by PSR is a long-term generation and interconnection planning model that determines an optimal expansion plan under uncertainty.

OptGen decomposes the planning problem into two components: investment and operation. The Investment Module uses capital and fixed operation cost data along with generalized constraints to reflect policies and guidelines (e.g., emissions reductions targets, firm energy or capacity targets) and uses an estimate of operating costs provided by the Operation Module, which SDDP. This integration with SDDP ensures that the expansion plans must consider the same uncertainties that are visible to the dispatch model.

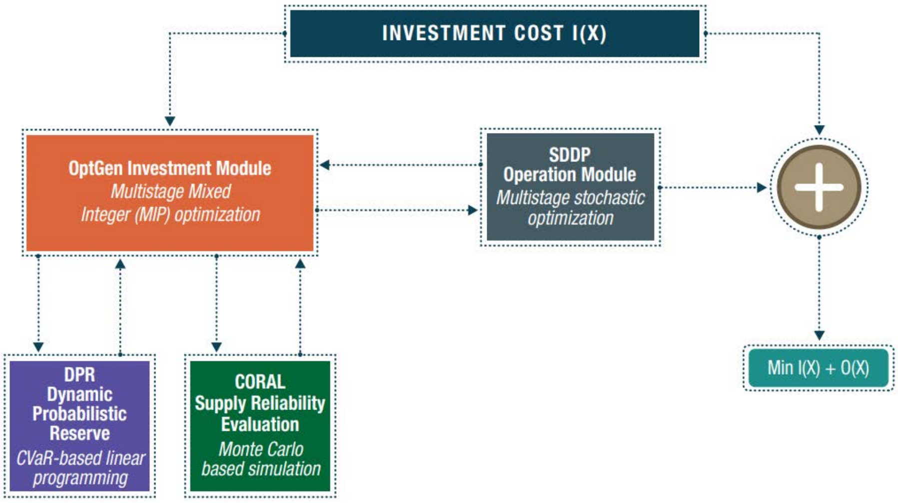


Figure A-31. OptGen schematic

A.3 Time Series Lab

Times Series Lab (TSL) by PSR is a renewable resource modelling tool that retrieves historical trace data for variable renewable energy (VRE) source and develop synthetic traces that are appropriate correlated spatially and temporally with hydro inflows.

TSL extracts historical data from the MERRA-2 global reanalysis database, which can then be calibrated using actual generation data and converted into wind or solar farm production by specifying turbine/panel type, hub-height, tracking behaviour, and other characteristics.

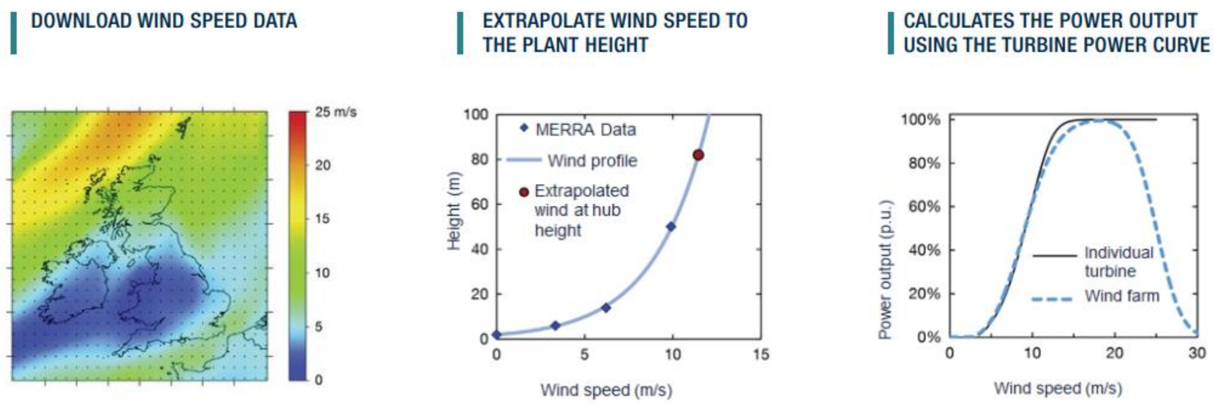


Figure A-32. Timeseries Lab

Appendix B. Non-utility solar and BESS costs

The table and chart below present the declining non-utility solar and BESS costs provided by Rewiring Aotearoa and used in the capital cost calculations in this analysis.

Figure B-1. Non-utility Solar and BESS capital costs

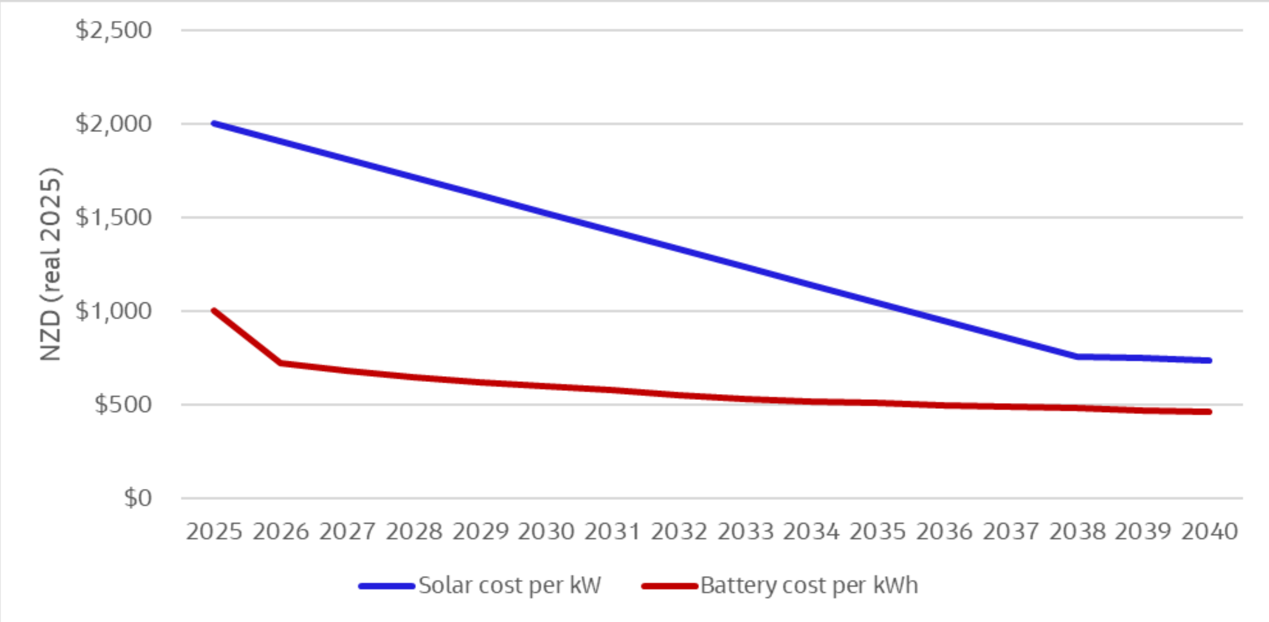


Table B-1. Non-utility Solar and BESS capital costs (real 2025 NZD)

	Solar cost per kW	Battery cost per kWh (2-hour BESS)
2025	$2,000	$1,000
2026	$1,904	$719
2027	$1,809	$679
2028	$1,714	$644
2029	$1,619	$621
2030	$1,523	$598
2031	$1,427	$575
2032	$1,332	$552
2033	$1,237	$528
2034	$1,141	$518
2035	$1,046	$508
2036	$950	$499
2037	$854	$489
2038	$759	$479
2039	$748	$469
2040	$737	$459

Appendix C. Present value supply system costs

Table C-1, below, is the tabulated values from Figure 18 showing the present value supply systems costs.

Table C-1. Present value system supply costs by case (NZD billion real 2024Q4)

	Emissions Cost	Load curtailment Cost	Thermal fuel and operating costs	Grid-scale CAPEX and Fixed Costs	Non-Utility CAPEX	Total
Base	$ 2.85	$ 0.06	$ 2.96	$ 34.57	$ 2.82	$ 43.25
Rewiring Case 1	$ 2.11	$ 0.04	$ 2.86	$ 18.93	$ 49.37	$ 73.31
Rewiring Case 2	$ 2.64	$ 0.04	$ 2.86	$ 20.94	$ 30.48	$ 56.95