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NZ Battery – electricity market study

Problem 2: Market Interaction

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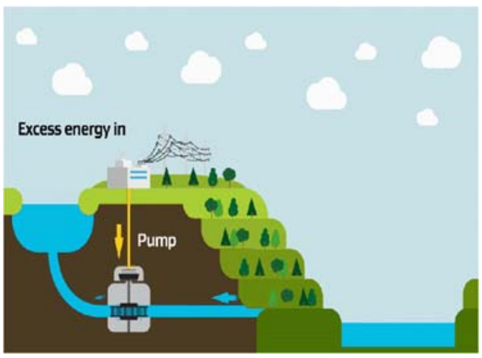

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Glossary

Abbreviation or term	Stands for
CCC	Climate Change Commission
CE	Contingent event
CFD	Contracts for differences
Code	Electricity Industry Participation Code
DSR	Demand side response
ECE	Extended contingent event
ETS	Emissions Trading Scheme
GIP	Grid injection point
GW, GWh	Gigawatt, gigawatt hours
GWAP	Generation weighted average price
HHI	Herfindahl-Hirschman Index
HVDC	High voltage direct current transmission interconnector AKA the Cook Strait Cable. It is made up of three links known as Pole 1, Pole 2 and Pole 3.
ICCC	Interim Climate Change Committee
ILR	Interruptible load reserve
kV	Kilovolts
LCOE	Levelised Cost of Energy, defined as the constant average annual electricity price attained by the plant over its lifetime that just achieves target return on investment after covering all cash costs
LRMC	Long Run Marginal Cost, defined as the minimum increase in total cost associated with an increase of one unit of output when all inputs are variable
MW, MWh	Megawatts, megawatt hours
n-1	Operating security standard where the power system is run to allow for the tripping of the largest risk (plant) without activating automatic load shedding
NI WCM	North Island Winter Capacity Margin
Nodes	Points on the grid where electricity is either exported (generation) or imported (consumption)
O&M	Operations and maintenance
OCC	Official conservation campaign

ORDC	Operating Reserve Demand Curve
PLSR	Partially loaded spinning reserve
ROI	Return on Investment
SFT	Simultaneous feasibility constraints. These protect one line from overloading post the loss of another line
SLR	Supplier of last resort
SOE	State-owned enterprise
SOS	Security of Supply
SRMC	Short Run Marginal Cost, defined as the change in short run total cost for a change of one unit in output
TWAP	Time weighted average price
TWD	Tail water depressed
VoLL	Value of Lost Load

Executive summary

Our brief and the problem definition

Our brief is to address how any large-scale dry year storage mechanism (NZ Battery) would interact with and affect New Zealand's current electricity market. We have interpreted the current market in this context as the operation of the existing market design and institutions after the 100 per cent renewable electricity policy in 2030 has come into effect.

The dry year risk problem the NZ Battery Project is considering arises as the consequence of removing fossil-fuelled thermal generation from the market. Historically, fossil-fuelled thermal generation has provided dry year cover and peaking duties. The question is whether the market will provide dry year cover after that transformation to 100 per cent renewable electricity has taken place or whether there is a case for a further intervention in the market.

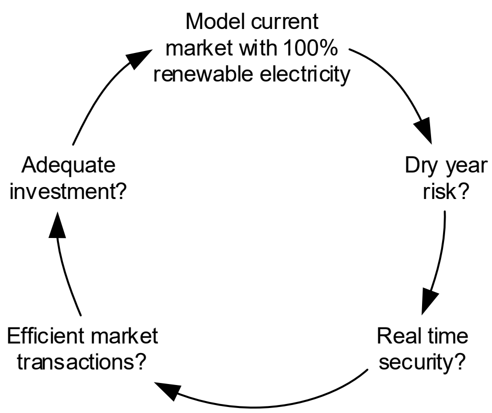
The case for an NZ Battery solution would be made if, in a 100 per cent renewable electricity world, security of supply would not be assured by the market at an overall cost less than the cost of the market with NZ Battery. If the proposed solution that comes out of the NZ Battery project is the Lake Onslow Pumped Hydro Scheme (Onslow), other effects resulting from Onslow's location would also have to be taken into account before proceeding.

Any assessment of the workings of the market also has to take into account whether the market will continue to perform its core roles once the 100 per cent renewable policy was introduced and again if Onslow is added into the market. The core policy objectives for the market are to deliver efficient market transactions and providing adequate investment in generation, all the while providing security of supply. The challenge to deliver adequate investment is heightened by the combined need to replace the fossil-fuelled generation in the move to 100 per cent renewables and then the reliance on electrification for decarbonisation under the net zero carbon 2050 legislation.

Our analytic approach

The analytic logic we applied is shown in Figure 1 below. First, we carried out the modelling with the current market design and fossil-fuelled thermal removed as at 2030, which is, for this purpose, the current market. We applied the tests as shown. We then reran the model with an Onslow pumped hydro scheme in operation and repeated the tests.

Figure 1: Ilustrative analytic approach to the "current market" with and without Onlsow



The thinking behind this approach and the outputs from the modelling provide an initial look at the decisions that have to be made and the impacts of those decisions in an integrated way, which will, in turn, inform the development of the case to construct Onslow and/or any other required scheme.

We have had to make an assumption about the operating model for an Onslow scheme. We considered a range of governance models and operating regimes. For this first look at how Onslow would interact with the market we have assumed it would be run by an independent regulated entity with an operating regime of buying (pumping) when prices are low and selling (generating) when prices are high. Managing dry year risk would be the entity's preeminent objective. We also assume that the conventional water values approach to hydro pricing is used to inform the agency's offer strategies. We have shown the possible revenue implications of that operating regime but have not considered how unmet costs would be recovered. If costs were to be recovered by levy on consumers, for example, that would change the price outcomes from the modelling.

An important issue we have taken into account, and an important issue for the whole market, is that price formation in a 100 per cent renewable electricity world will be quite different than it is today. After the shift to 100 per cent renewable electricity, the offer curve – and, as a consequence, cleared prices – will have a greater incidence of low SRMC based prices and potentially a higher incidence of prices that reflect scarcity. In lay terms, compared to a market with thermal generation, it will be a market with lower prices most of the time, but with an increased chance of occasional very high prices. We consider the shift in prices resulting from that new price formation dynamic in the 100 per cent renewable case to price formation after Onslow is added into the 100 per cent renewables market.

We have focused our analysis on a pumped hydro scheme at Lake Onslow because this scheme is documented and has the potential scale to address the problem the NZ Battery project is looking at. However, our analysis has shown that large-scale storage in the South Island leaves unsolved problems for the system in the North Island after fossil-fuelled thermal is removed. The problem intensifies with increased demand from electrification.

Modelling results

The modelling reflects the iterative approach shown above. The modelling tests for the level of prices that would encourage enough generation investment to meet dry year risk for the given set of circumstances. For the first step to 100 per cent renewable electricity supply, the level of generation required is referred to as "overbuild" because much of the available renewable generation uses fuel supply that cannot be stored. That is to say it is the amount of generation required in a dry year and, by implication, some of it would not run to commercial level of capacity utilisation in other conditions. The concept of overbuild carries through when Onslow is introduced, but the amount of required overbuild is reduced.

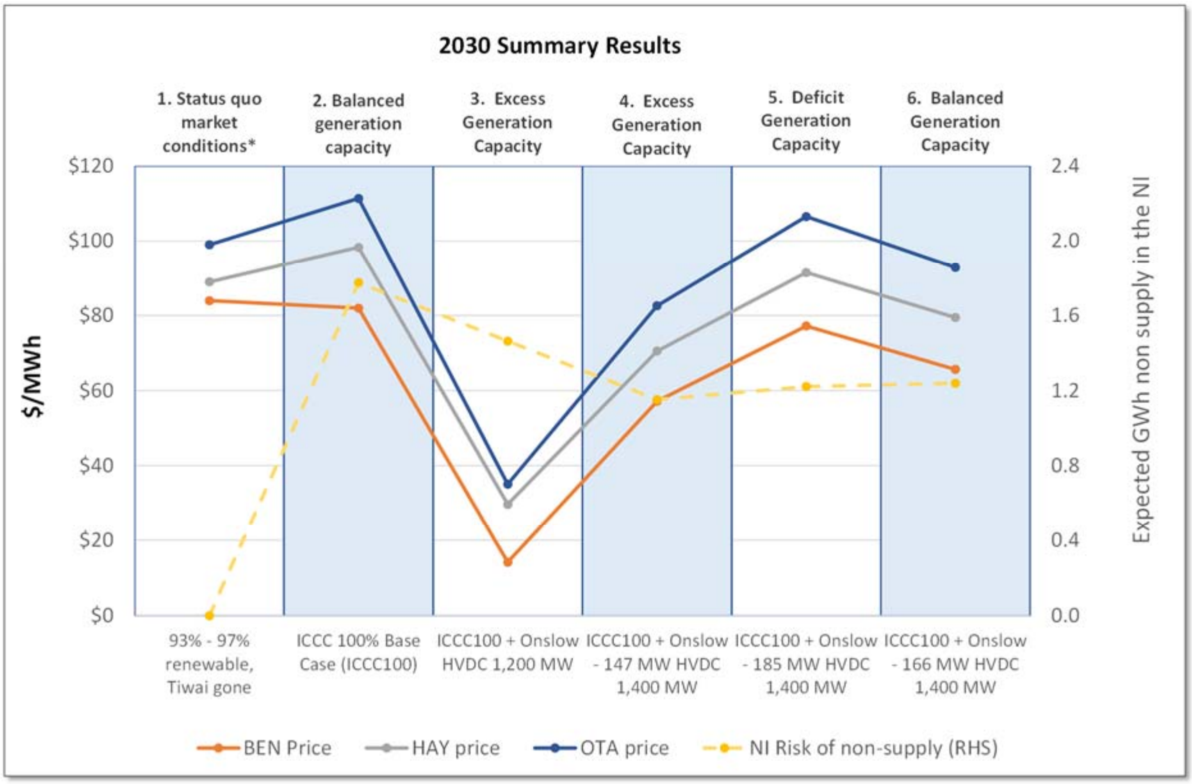
In both 2030 and 2050, the market was modelled initially without Onslow, with only enough new plant built so that each achieves its target Return on Investment (RoI),[1] more or less, in the year of interest. To build more new plant than this would depress prices, causing new generation to fall short of its target RoI, and to build less would see new plant recovering greater than target RoI, neither of which

[1] The test is actually performed on target EBITDAF, which includes cash RoI.

is likely, on average, in a competitive market.[2] This test for new plant building is not an exact test, but the results are sufficient to inform the questions we have been asked. Figure 2 and Figure 3 show the results on the modelling for 2030 and 2050 as a series of progressions.

Scenario 1 of Figure 2 shows the expected prices in 2030 and the risk of non-supply in the North Island under current arrangements i.e. with fossil fuelled thermal generation still performing the roles it performs today. Scenario 2 shows prices where there is enough investment in the market to cover dry year risk but there is a risk of non-supply in the North Island with the change to 100 per cent renewable electricity supply. The prices reflect the levels required to attract the investment in new generation necessary for a secure system.

Figure 2: Summary results for 2030. ICCC 100% renewable electricity base case with Onslow added and then capacity reduced to balance the system. Risk of average non supply in the North Island is also shown.



Scenario 3 shows the drop in prices that would result from the introduction of Onslow into the market (based on 5,000 GWh storage and 1,000MW generation capacity). Critically, the risk of non-supply in the North Island is stubbornly high compared to the market with fossil-fuelled thermal peakers available for this role. We have labelled this scenario excess generation capacity because that is effectively the price signal the market receives in this instance. We have removed some of the new built generation (over capacity) and expanded the capacity of the HVDC in scenario 4. Prices are more attractive to investors, and the risk of non-supply in the North Island declines. In scenario 5, by removing additional new build, prices step up again but now signal a deficit of generation capacity

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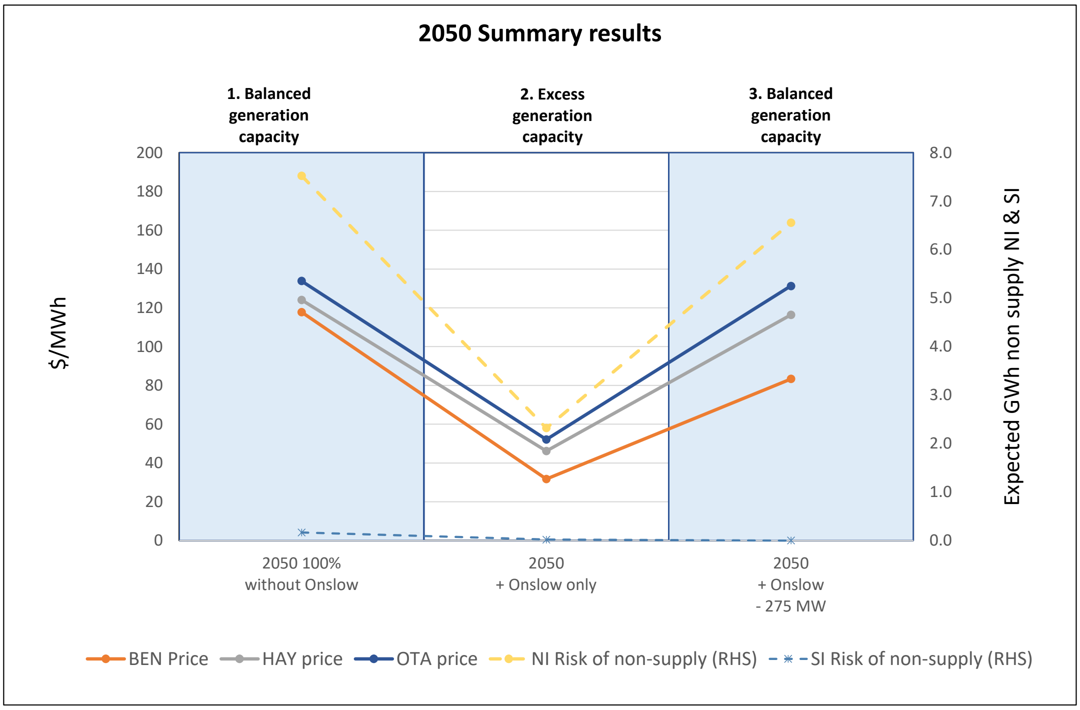
[2] After 2008 we saw a period of years when demand was expected to follow its long-term growth path, and a lot of new capacity was added through to 2014. However, the growth rate of demand fell dramatically after 2008, and the end result was a surplus of capacity.

compared with the levelised cost of new generation. Scenario 6 balances generation build, investment signals and dry year cover with Onslow in the market. The risk of non-supply in the North Island remains.

In Figure 3 we set out the results of the modelling for 2050 using the same conventions as above.

Scenario 1 shows prices required to attract the level of investment (overbuild) needed to achieve security of supply with 100 per cent renewable electricity supply without Onslow in 2050. These prices are 40 per cent higher than the equivalent scenario in 2030, which reflects the higher demand expected by then. The risk of non-supply in the North Island is higher by a factor of 4 compared to the 2030 equivalent. Scenario 2 shows the price outcome with Onslow introduced but without adjusting the generation build. Dry year risk is managed and the risk of non-supply in the North Island falls, but at those prices the necessary investment in new generation would stall. Scenario 3 shows balanced dry year cover and generation capacity with Onslow in the market. The price outcomes would continue to attract the necessary level of investment to balance the system and deliver security of supply.

Figure 3: Summary results for 2050. ICCC 100% renewable electricity base case 2050 with Onslow added and electrification demand. Risk of average non supply in the North Island and South Island shown.



The risk of non-supply in the North Island reflects the expected lack of capacity in the North Island, combined with constraints on the HVDC and even the risk of the HVDC failing (although that is a low probability event). It is also an indicator of a lack of diversity due to locating the major security of supply mechanism at Onslow or elsewhere in the South Island. Table 1 below reflects the risk to security of supply based on the assets available under four different scenarios. This illustrates the shift in reliance on hydro storage, the HVDC and AC grids that results from the shift to 100 per cent renewables, and then with the addition of Onslow compared to the diversity we have today.

Table 1: Diversity and reliance on key assets

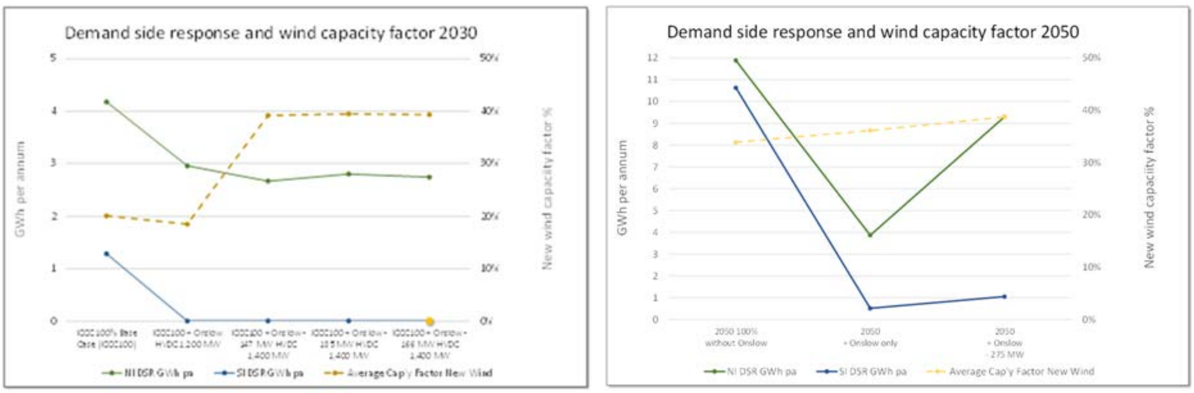
	Reliance on Key Assets for Security										
Scenario	SI hydro	NI hydro	Wind	Solar	Coal	Gas	Other	Storage excl Hydro	HVDC Link	AC Grids	Diversity Score
Present day	High	Low	Medium	Zero	Medium	High	Low	Zero	Medium	High	High
95% renewables	High	Low	Medium	Medium	Zero	Medium	Medium	Zero	Medium	High	High
100% renewables - ICCC 100%	High	Low	High	High	Zero	Zero	Medium	High	Very High	Very High	Low
100% renewables with Onslow	High	Low	High	High	Zero	Zero	Medium	Very High	Very High	Very High	Low

Figure 4 picks up two other dimensions from the results: demand side response (DSR) and wind capacity factors. The simple point about DSR is that the market would need a great deal more DSR than is available to the market today to provide secure dispatch with 100 per cent renewable supply.[3] If Onslow were to proceed it would reduce the need for more DSR but the market would still require far more than today.

The average wind capacity factors in 2030 start very low without Onslow, because the amount of DSR and supply of last resort (SLR)[4] modelled is sufficient to incentivise over-building of windfarms. But with Onslow, overbuild of wind capacity can be reduced, and capacity factors restored somewhat.

In 2050 the wind capacity factor is also low without Onslow, but not as low as in 2030, because the 2050 market is slightly under-built. The modelling issue here is that the high occurrence of very high prices makes the market very sensitive to small changes in the amount of new plant built.

Figure 4: DSR and capacity factor of new windfarms in 2030 and 2050

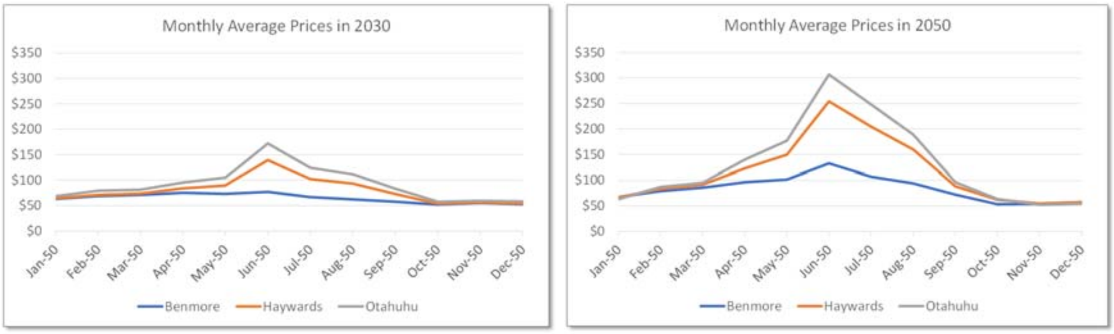


[3] We understand that more DSR will become available by virtue of the penetration levels of batteries accompanying solar systems, EV chargers and digital energy management systems but we haven't assessed the quantum of that compared to the future requirements for this work.

[4] Priced at $10,000/MWh and which could include non-supply.

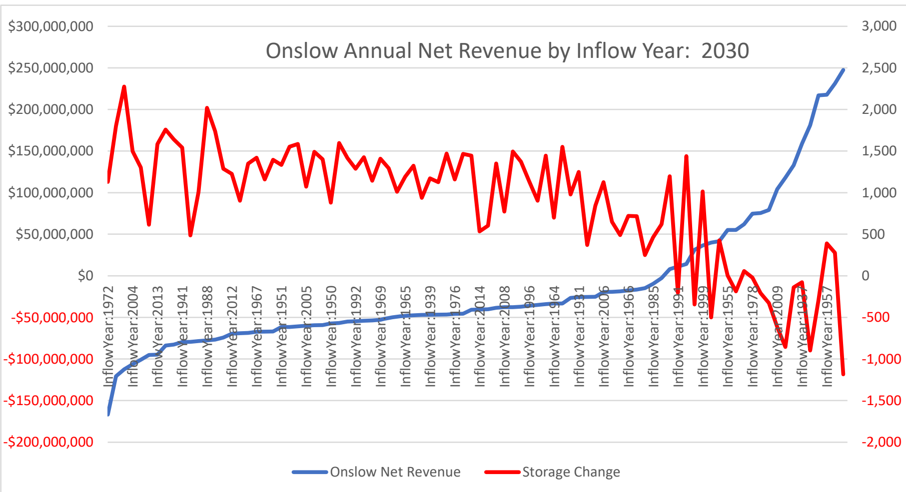
The average annual intra-year spread of prices in 2030 and 2050 is shown in Figure 5. These absolute prices in winter are interesting but, more critically, the effect of the inevitable incidence of constraints binding at the HVDC under an Onslow-only scenario is clearly observable. These price differentials could be addressed with increased HVDC capacity or addition of a North Island option under the NZ Battery project. If we accept that increasing reliance on the HVDC link does nothing to improve diversity and to lower the risk of non-supply, then this shows that the renewables intermittency drives the market need for additional storage solutions in the North Island.

Figure 5: Monthly average prices 2030 and 2050



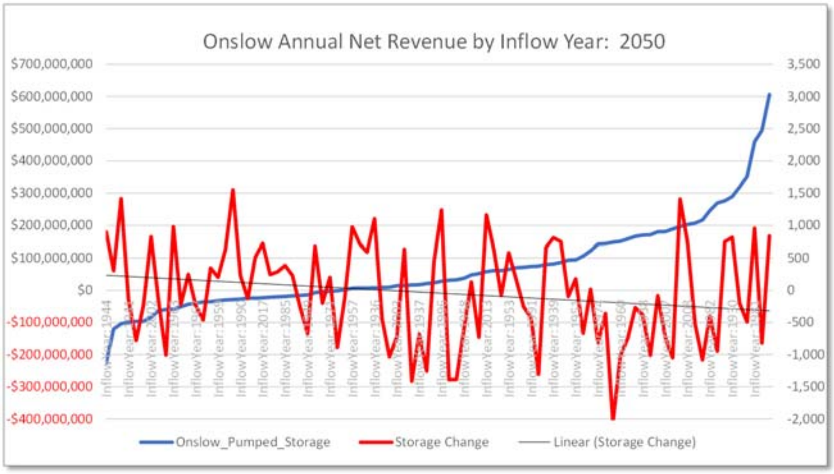
Finally, we show in Figure 6 the modelling results of annual storage change and net revenue achieved by the operator of Onslow using the full range of historic inflows. Based on the sub-set of years in which storage ends at about the same as it started, then the annual net revenue is between $55 million and $90 million.

Figure 6: Onslow net revenue distribution and storage change 2030



In 2050 the correlation with storage change is not as marked because in this scenario the average start and end storage are about the same, and average net revenue is $66 million.

Figure 7: Onslow net revenue distribution and storage change 2050



Modelling key takeaways

- Adding Onslow to the market after supply becomes 100 per cent renewable achieves the objective of reducing the additional generation capacity required to achieve SoS.
- Onslow also contributes substantially to preserving security but is limited in the contribution it can make to North Island security by the capacity of the HVDC link.
- The combined effect of removing fossil-fuelled thermal generation in the North Island and building Onslow in the South Island reduces the overall diversity of the electricity supply system and increases its reliance on the HVDC link compared with the present.
- With or without Onslow, 100 per cent renewables in 2030 presents a substantial challenge to get enough plant built to preserve security: the market essentially pays a premium for generation that comes with fuel storage ability and, by default, pays less of a premium for plant that doesn't. We refer to plant with no storage capability as intermittent, which covers wind, solar and hydro that doesn't have meaningful storage capability. The overbuild required to provide security of supply in future will be largely intermittent generation.
- Onslow has to be filled to its normal operating range, within a reasonable time. That can either be achieved by allowing fossil-fuelled thermal generation to remain in the market for a year or two after Onslow is commissioned, or bringing forward renewable generation needed to cover ongoing load growth through the electrification expected to deliver the decarbonisation objectives.
- Operating Onslow with a bid and offer strategy based on water values would achieve positive net revenue on average, but there would be a large range from very negative to very positive, depending on prices and hydrology in each year.
- Adding Onslow reduces prices and price volatility to a modest extent compared to the situation with 100 per cent renewables in the early years. However, by 2050 in the North Island, price pressure and volatility is evident where meeting peak demand presents significant challenges.
- In 2030 and 2050, the HVDC link constraints lead to persistent price separation between North Island and South Island prices. In particular there would be extremely high prices

when DSR and SLR is dispatched, which depresses, in turn, the realised prices for wind and solar farms in the North Island relative to geothermal stations; these imbalances indicate the value of significant amounts of storage in the North Island and/or of significant transmission investment.

- The current market structure may not deliver sufficient spare capacity to ensure there is always enough standby reserve capacity available and to refill Onslow after a dry year.[5] We expect this will be the subject of further study following the completion of this work.

Implication for the next phase as MBIE develops the scope for the business case for NZ Battery

We have:

- considered the policy context in which the NZ Battery study is being conducted
- developed a default operational model and pricing approach for an Onslow project for the purpose of testing how an NZ Battery solution would interact with the market
- analysed the likely security of supply and security settings in the current market with fossil-fuelled thermal removed in line with the 100 per cent renewable electricity in 2030 policy. We have shown that either the market has to overbuild a great deal to provide security of supply or Government can intervene so the market requires less overbuild, it can continue to fill all of its roles and security of supply is assured.
- projected the security of supply and security settings in 2050 with Onslow in the market and the market design otherwise unchanged
- taken into account advice from MBIE and the team working on problem 1 on the method of intervention to meet government objectives
- demonstrated the market impacts of the intervention based on the Onslow scheme, notably the loss of diversity in the system and the risk of non-supply in the North Island under certain conditions.

This work provides the NZ Battery project a framework for thinking about the operation of a state-owned intervention in the market and sets out a full range of matters we recommend should be taken into account. The implication for the next phase of the project is that all of these matters should be resolved when the business case for a project is developed.

[5] The fossil-fuelled thermal fleet currently adds to security in the form of actual generation, but also in the form of 'standby reserves': this is plant that is offered but not dispatched, either for energy or reserves. If an outage occurs, reserves act to bring the frequency back into the frequency-keeping control zone, within the 15-minute offload time specified by Transpower. But after 15 minutes, it may be standby reserve capacity that is dispatched to replace the outaged plant.

Introduction

New Zealand has operated an energy-only wholesale electricity market since 1996. The market has been tested a number of times, governance arrangements have been changed twice, the Crown briefly re-entered the market, new participants have entered, existing participants have departed, consumers have been increasingly included in decision making, behaviours have been investigated, and outcomes have been challenged. The Crown's expectations of the market have evolved, most notably with the recent requirement of Government that electricity supply should come 100 per cent from renewable sources by 2030.

To date, thermal has filled several roles in the market, including peaking duties (security) and management of dry year risk (security of supply). With fossil-fuelled thermal gone, the market may struggle to fill those two roles. In addition, the Government's GHG emission agenda relies heavily on electrification of transport and process heat. As a result, demand may increase in the order of 50 per cent by 2050. The combination of removing fossil-fuelled thermal and increasing demand will test the market.

The move to 100 per cent renewables leads Government to ask the question whether the market will deliver an acceptable level of security of supply at least cost to New Zealand. Governments have asked this question before the market was conceived and at a number of points through its history, so this is not novel. The corollary is if Government cannot be confident that security of supply will be maintained without fossil-fuelled thermal in the market, it must consider what forms of policy intervention are available to it. The Government's focus is a storage option such as a pumped hydro storage scheme. Given the scale required, this could lead to two new pressures on the market: the Crown may re-enter the market, and the operation of the scheme could change market dynamics. We have been asked to consider the impact of an NZ Battery option, potentially owned by the Crown, entering the market.

First, we consider what the wholesale price distribution might be without fossil-fuelled thermal in the market and the implications for investment and security of supply. Then we consider how an NZ Battery solution might functionally interact with the market in 2030 and 2050.

The issue around what wholesale price distribution looks like without fossil-fuelled thermal in the market is significant. Fossil fuelled thermal generation has performed a substantial role, directly and indirectly, in price formation since the inception of the market and price formation will be very different without it.

The iterations show that price formation and the need for ongoing investment in the sector exposes a risk for North Island security if the dry year risk solution is Project Onslow, i.e. a large battery solution located in the South Island. If Onslow is the preferred solution for security of supply in a 100 per cent renewable market, we show that the solution may have to include a component in the North Island or expanded and more reliable grid capacity. If the NZ battery solution has two components that may complicate the governance and operating arrangements.

Our engagement

MBIE has engaged Sapere to assist with the development of the initial scope and assumptions for the business case evaluation for the NZ Battery project, specifically how any NZ Battery project will interact with and affect New Zealand's current electricity market. Sapere has teamed up with Energy Link and Chapman Tripp for this assignment.

MBIE is the primary government department responsible for advice to the Government on energy issues and associated legislation and regulation. The NZ Battery is a project being administered in its initial phases by MBIE.

The NZ Battery project is a government initiative to develop the business case for a solution or solutions to New Zealand's dry year risk problem, whereby in years with low hydro inflow, electricity generation can face a shortfall on average of around 5,000 GWh.

The Government has allocated a multi-year appropriation of $100 million to fund the project. The project is divided into phases. The first phase is the business case evaluations ($30 million), and the second phase is the engineering design of the selected options ($70 million). The project is being managed by a core project team, supplemented through services procured through a number of consultancies.

The NZ Battery project is established in conjunction with the Government's goals of 100 per cent renewable electricity by 2030 and net zero carbon by 2050. The central issue is how to best meet these goals while maintaining security of supply. This requires an examination of potential energy storage solutions and the consideration of the costs and benefits of each and what trade-off may need to be considered. In order to commence this work, MBIE identified two interrelated problems that should be addressed at the outset:

- Problem 1: Dry Year Size
- Problem 2: Market Interaction.

This report focuses on Problem 2: Market Interaction. The work has been conducted in parallel with work that focuses on Problem 1: Dry Year Size.

Problem 2: Market Interaction

The NZ battery project provided the following background to our assignment:

> The second problem MBIE is looking to address is how any dry year storage mechanism will interact with and affect New Zealand's current electricity market.
>
> Currently New Zealand operates an energy-only electricity market; that is, no separate capacity payment or similar mechanism exists. Experience from the government operation of the Whirinaki diesel power station a decade ago was that it was thought to have deferred private investment in generation. A dry year solution may have a similar effect, particularly if its operational rules permit it to operate at times of high prices, as well as low water storage.

Conversely, a dry year solution, such as a pumped hydro that purchases energy at low prices, may act to stabilise income streams for intermittent renewables, by removing very low to zero prices.

Accordingly, our deliverable is an assessment of how the currently configured electricity market would be affected for given levels of dry year storage invested in by the Crown under a range of operating arrangements.

The insights and information provided in the deliverable will inform the identification of an NZ Battery solution. It should include inputs into the initial scope and assumptions for the business case evaluation for the NZ Battery project. We understand it will help establish the framework for subsequent analysis.

Moving to 100 per cent renewables

Policy objective

The broadest context for this task is the role of the electricity market. Liberalisation of state ownership of electricity generation and the introduction of wholesale markets was intended to address a number of roles which, in turn, would satisfy public policy objectives. The overarching question now facing the sector is whether the market in New Zealand will still be able to carry out all of those roles and meet the accompanying public policy objectives without fossil-fuelled thermal generation. Implicitly, if the answer is no, the need for an NZ Battery solution is made, and then the question is whether the market in New Zealand will still be able to carry out those roles and meet the remaining public policy objectives without fossil-fuelled thermal and with the NZ Battery project in place. In order to address those questions we have to also understand the likely operating model for any such project.

To recap, after more than two decades of retail competition and a wholesale market for electricity, the New Zealand electricity sector is performing reasonably well. Governance has changed along the way, issues have been debated, many improvements to the Code have been made, retail competition has demonstrably improved, dry years managed, and renewable generation built. For the most part, the sector has delivered the outcomes expected of it. There are areas where the industry hasn't done itself any favours. For example, increases in retail prices have not been well explained to consumers, and as a result consumers remain unconvinced that electricity prices are fair and reflect reasonable costs. Another example is the current trading environment where a constrained gas system on top of low hydro levels is leading to unprecedented and sustained high wholesale electricity prices.

One way to assess outcomes from the electricity sector is to analyse those outcomes against the following five public policy objectives—objectives that are enduring for policy makers across countries and time:

- security of supply – in the sense of supply meeting demand continuously without involuntary cutting of supply, or a heightened threat of cuts to supply
- efficient operation of the wholesale and retail sectors, with competition a primary tool for achieving efficiency
- efficient use of, and investment in, long-life assets (including transmission and distribution), guided by economic regulation
- meeting community or social minimums, including universal access to electricity and support for those who can't pay
- integrating environmental objectives while mitigating the impact on the industry of achieving these objectives, with a current focus on climate change.

From time to time, outcomes under one or other of these public policy objectives come to the fore, leading to heightened interest from – and potentially intervention by – government. In this report we take account of the sector's outcomes against each public policy objective, first with the implementation of the 100 per cent renewable electricity policy in 2030 and then the addition of an

NZ Battery solution based on an assessment of a full range of operating models. This is the same framework we used in our 2009,[6] 2014[7] and 2018[8] reports.

Underlying this framework is the idea that the wholesale market design we have supports and does not undermine all of the policy objectives. This was questioned in 2006 and 2009:[9]

> December 2006: Electricity Market Review A review of the electricity market, prompted by ongoing concerns about security of supply and price increases, was completed. The review concluded that the performance of electricity market arrangements had been mixed, and that while the current regulated market should be retained, a range of enhancements should be pursued to improve performance, particularly regarding security of supply.
>
> April 2009: Ministerial review of electricity market A Ministerial review of the electricity market was announced, with the review team being supported by a technical advisory group of six independent experts. The review was to examine market design and regulation and governance issues, drawing on work done by the Electricity and Commerce Commissions as input to the review.

Changes to market design were contemplated in 2014 although no action followed. Outcomes from the market were tested again in the 2018 Ministerial Review, and changes arising from that review continue to be implemented. Security of supply wasn't at the centre of this 2018 review. However, the 2018 review reinforced the needs for market solutions to be equitable:[10]

> In April 2018, the Minister of Energy and Resources commissioned an independent review into New Zealand's electricity market. The 2018-19 review was unique as it addressed the need for electricity prices to be fair and affordable, not just efficient or competitive. Another novel element was the review's focus on the consumers' point of view and their say in the direction of the sector.

Using this framework to describe the context for this paper, Government has introduced a policy targeted at environmental goals (100 percent renewable) that may impact on the electricity market's ability to deliver on the security of supply objective. The NZ Battery project is a response to the possible implications for security of supply. To answer the question that is the subject of this work, we need to assess whether the other ever-present policy goals (efficiency, investment, and equity of access to energy) would still be met with the renewable electricity supply target and an NZ Battery solution in place. Critically, the question is whether there will be sufficient investment in renewable generation and whether the wholesale market can still deliver efficient market transactions with the renewable electricity supply target and an NZ Battery solution in place.

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[6] Dr Graham Scott, Kieran Murray, Toby Stevenson (2009) *Determining outcomes or facilitating effective market processes: a review of regulation and governance of the electricity sector.*

[7] Kieran Murray, Toby Stevenson, Joanna Smith (2014) *Achieving policy objectives for the electricity industry.*

[8] Kieran Murray, Toby Stevenson, David Reeve, Corina Comendant, Ashley Milkop, Dean Yarrall (2018) *Electricity Sector Review 2018.*

[9] MBIE Energy Markets Policy Energy & Resources Branch, Chronology of Market design in New Zealand reform 2015.

[10] MBIE website https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price-2018-19/

Can we anticipate a problem?

If there is a problem, it emerges from the answer to the question: why wouldn't the current electricity market deliver 100 per cent renewable by 2030, and security of supply with equity, transaction efficiency and investment adequacy? Some background into our electricity market will be useful here.

The concept of the spot market for electricity was driven by a need to encourage efficient investment in, and to seek private capital input into, grid-supplied electricity generation. The driver overseas, and particularly in the USA, was ageing fossil-fuelled thermal plants that were highly inefficient. In New Zealand, increasing inefficiencies within the New Zealand Electricity Department were a concern, but so was the fact that 30 per cent of the Government's fixed budget was being spent on electricity projects. The solution was an observable, independent central spot pricing mechanism with prices based on the marginal cost of generation, combined with low barriers to entry for new investment.

When an electricity market is highly competitive, generators seek to gain whatever volume they can from the spot market, providing they recover at least their variable (SRMC) costs. Clearing prices are set at the offer price of the most expensive generator and so prices tend to be the SRMC of those plants under effective competition.

In the early days of an electricity spot market, this was all that was needed as the LRMC of new plant was less than the SRMC of old inefficient plant and was able to displace the end-of-life assets. However, markets soon rationalised, and the SRMC of the marginal plant was no longer sufficient to necessarily attract new investment, especially for security of supply.

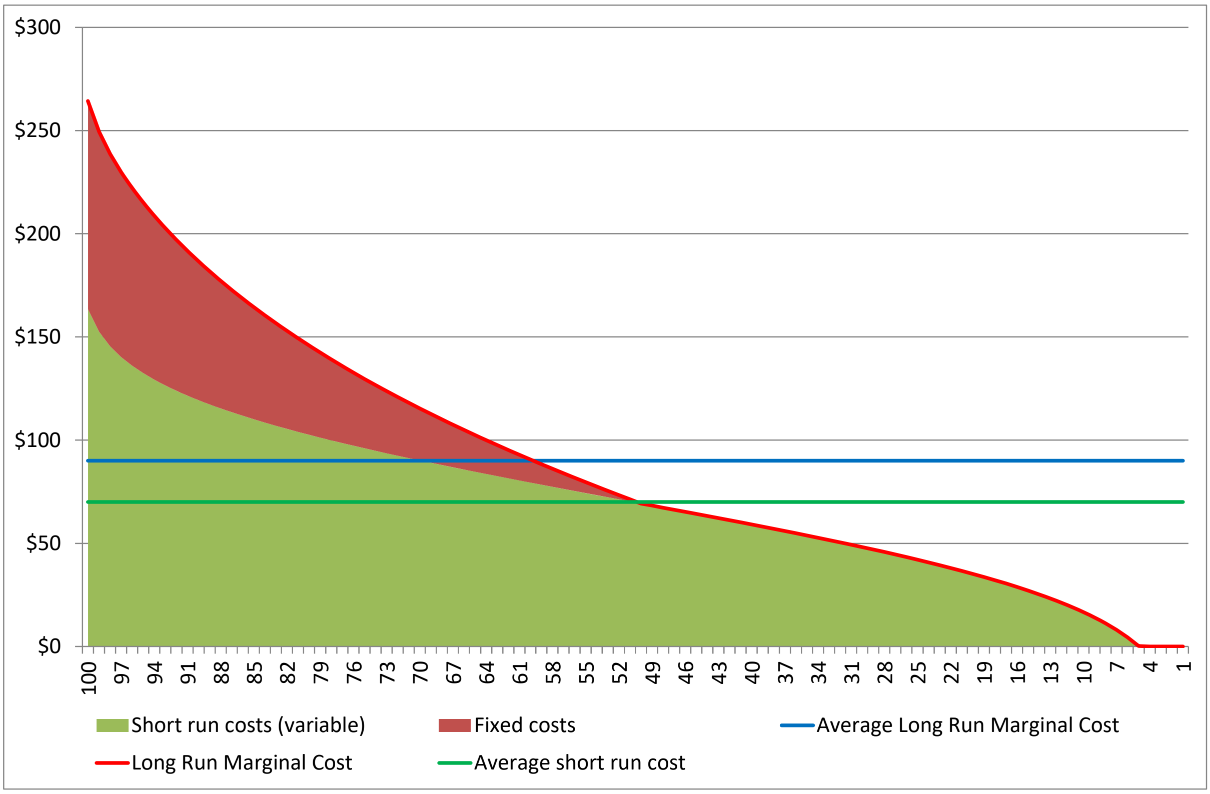
Many overseas markets, especially in North America, addressed this by having capacity markets. In a capacity market, generally, purchasers are given the obligation to secure enough capacity for their peak demand with a reserve margin. The purchasing of this capacity is intended to recover the fixed costs of generation, and the spot market is expected to clear at variable cost.

The capacity market mechanism couldn't work in New Zealand as, especially in the 1990s, New Zealand had plenty of hydroelectric peaking capacity. New Zealand's problem was dry periods and a need for firm energy to replace hydro for a period of up to many months. New Zealand's high proportion of hydroelectricity compared to overseas jurisdictions was also a factor. Hydro doesn't have significant variable costs in the sense of costs that are avoidable in the short run, but hydro must be priced in a market to ration storage and allocate it to periods where it is most valued. Instead, hydro plants offer on the basis of short run opportunity costs,[11] which easily adapt to the cost of scarcity. New Zealand needed a different mechanism.

The mechanism chosen had at its core an 'energy-only' market, which simply means no capacity market and prices are expected, at times, to rise above SRMC during times of scarcity to enable the recovery of fixed costs and enable revenue adequacy for new investment (see Figure 8).

[11] See explanation of water values in Appendix B.

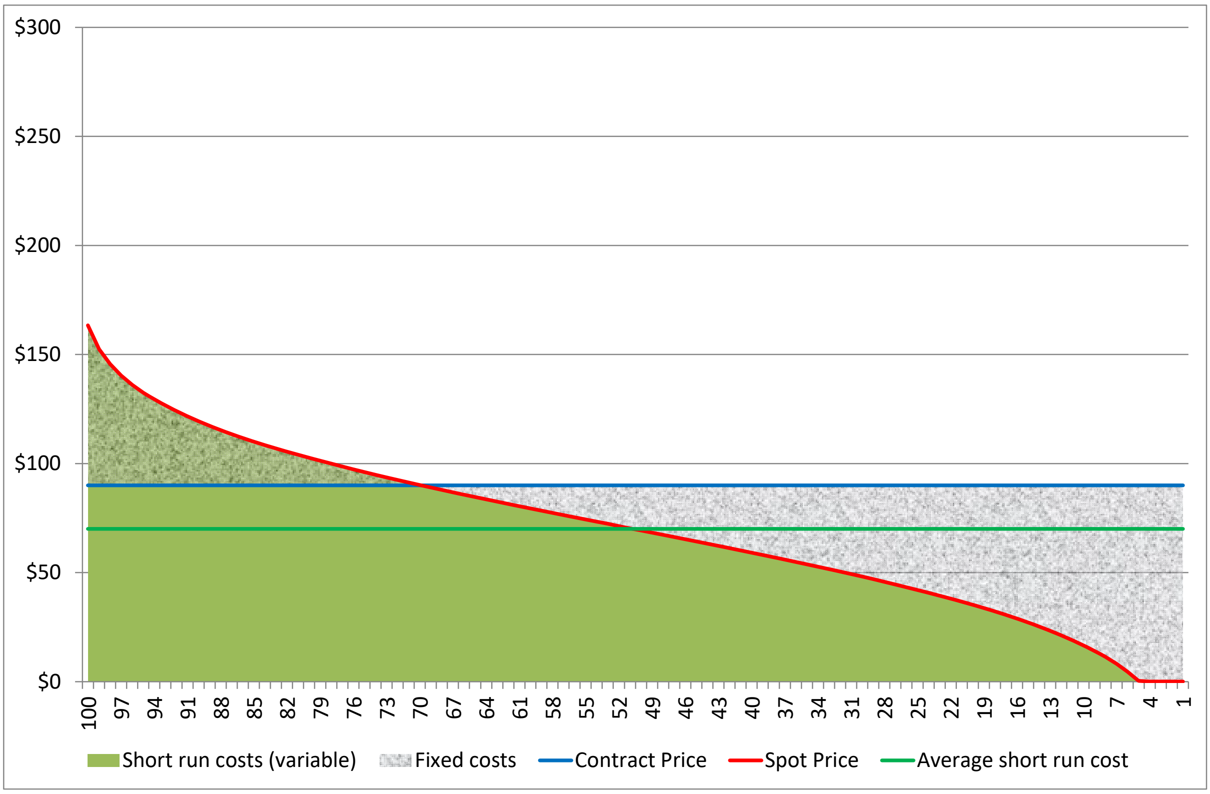
Figure 8: Illustration of how the energy-only market contributes to fixed and variable costs



However, an energy-only spot market also needs working contracts markets. Without financial arrangements to smooth cashflows, retailers could go bankrupt in one dry year and generators ensuring security of supply could go years before they stand a chance of making an economic profit. Contract prices should strike above the current average electricity spot price. This wedge between contract prices and the average electricity spot price is the risk premium for retailers to transfer their purchase volatility to a generator, and this risk premium pays for generator fixed costs (see Figure 15).

This might suggest that efficient contracts should be of long duration so that generators are sure of recovering fixed costs and purchasers are sure of managing risk. Theoretically, in a perfect contracts market where every party has the same information, understands the risk and there is no market power, then contract duration doesn't matter. Counterparties will be able to determine the efficient price. However, contract markets are never perfect and, in electricity, access to relevant information and understanding risk are particular problems. In this context, longer duration contracts don't help. The efficient price agreed between the parties is still a forecast and information asymmetry, hidden or misunderstood risks, and market power can still disrupt an efficient transaction.

Figure 9: Illustration of how contracts contribute to fixed and variable costs



As the generator now has the risk, through its contract obligations, and is recovering fixed costs, then the generator will run when it needs to at its SRMC. In other words, in theory and with effective competition, an energy-only spot market with a well-functioning contracts market achieves the same thing as a capacity market but with no regulatory intervention. However, how well functioning either the spot market and/or contracts markets are is often a matter of debate.

So the substantive question is: can the New Zealand energy-only spot market and accompanying contracts market function well – i.e. deliver a secure market, cover dry year risk, discover prices through a competitive process, incentivise sufficient investment, at prices consistent with equity of access – while moving to 100 per cent renewable electricity by 2030?

Can the current market deliver?

The distinction between New Zealand's electricity generation when the market started in 1996 compared to the market that would exist in a 100 per cent renewable 2030 is key to assessing the problem.

In 1996 there was sufficient fossil-fuelled thermal generation, with hydro operators' shadow pricing to fossil-fuelled thermal, that low prices weren't particularly low.[12] Fossil-fuelled thermal generation has high variable costs and relatively low fixed costs. Therefore, when hydro inflows were high, average prices were often still relatively high, and contract premiums, similarly, didn't need to be very high.

[12] See further discussion in Appendix B on water values

Even the low prices, at the time, were sufficient to make a significant contribution to the high fixed costs of hydroelectricity.

In the 2030 factual of 100 per cent renewable, two things are different:

1. There is a significant amount of generation, such as geothermal and wind, that has no opportunity or variable costs above its costs of operations and maintenance, which are low.
2. To clear any volume, hydroelectric operators need to shadow price to these low opportunity costs. To recover their fixed costs, prices must be set by reference to extremely high water values during periods of scarcity.

This yields very low prices for long periods of time with extremely high risk premiums over future prices then being required for contract prices. Several predictable dynamics flow from this new pricing landscape in a 100 per cent renewables market.

The incentive for retailers to ignore security of supply in favour of low spot prices, when they can, becomes very strong. Similarly, the incentives to seek political or regulatory remedy during periods of high prices are also strong. For generators, with market power but without contracts, years of sub-economic returns create strong incentives to lift prices higher than warranted during periods where the market favours sellers over buyers, given that it could again be some time before conditions are profitable again.

Even generators setting prices by reference to very high scarcity water values, but no more, face risks. While water values are a defined calculation, the inputs are not. If different assumptions are used about inflow distributions, potentially driven by different adaptions to the historical record to account for climate change, or about the risk and cost of shortage, then quite different water value calculations can occur. Hydroelectric generators face many risks of shortage, which include physical, operational, with environmental stakeholders, and portfolio risks that may be less or more than straight spot market risk. Additionally, hydroelectric generators, or new renewable generators for security of supply, will optimise their resource value for their own portfolio, whereas a regulator, seeking to check prices, will use a global optimisation. Different approaches will give different water values with neither party necessarily being wrong.

If a regulator is under pressure to 'correct' market prices and, having calculated its own water values, is seen to adjust prices in the few periods where security of supply generators are profitable, then this can disincentivise investment, even if the regulator's calculations are correct and justifiable.[13]

[13] The issue that generators may not be able to recover the full cost of providing security of supply as well as energy is often referred to as the missing money problem. Hogan (2005) describes this: "Electricity resource adequacy programs often target the 'missing money' problem. The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants. The resulting missing money reduces the incentives to maintain plant or build new generation facilities. In the presence of a significant missing-money problem, alternative means appear necessary to complement the market and provide the payments deemed necessary to support an appropriate level of resource adequacy."

Such a correction may not always revise prices down. While regulators will be concerned to let prices rise too high, they are also cognisant of the role of scarcity pricing for price formation. A power system that can easily supply even the highest of peaks is an expensive system because it is almost certainly overbuilt. In practice, the highest peaks that can occur will stretch the system to the limit. In the worst case the market cannot clear, i.e. there is insufficient generation available for the worst peaks to supply demand and retain prudent levels of reserve generation. In this case the System Operator has no option but to accept a lower level of security for the short duration of the peak. However, prior to 2009, by relaxing the security constraints in the market pricing model, prices would drop. This was the wrong outcome as the reason for the relaxation was that there was insufficient generation and yet the price for generation was arbitrarily low.

The Ministerial Inquiry of 2009 made recommendations on this that were given effect under section 42(2)(b) of the Electricity Industry Act 2010. This addressed the issue by recommending a scarcity pricing regime whereby, in a situation where the lack of peak generating resources might constrain the market price model and lead to lower prices, a scarcity price should be administered.[14] As the market solution required a relaxation of security standards, increasing the chances that load would be interrupted, the recommendation was that the scarcity price should be equal to the Value of Lost Load (VoLL). It was determined that the administered scarcity price should be no less than $10,000/MWh and no more than $20,000/MWh. In the latter case of $20,000/MWh it was determined that, for any solution that cost more than $20,000/MWh, that it would be more economic to reduce load, preferably the most price-sensitive load.

The scarcity pricing regime is, in effect, performing some of the role of a capacity market. By ensuring prices don't go too low during periods of scarcity, the scarcity pricing regime:

- provides incentives for short-term peaking solutions
- lifts the average generation price, helping the recovery of fixed costs
- increases the cost of shortage for hydroelectric operators, affecting water value calculations.

Evidence

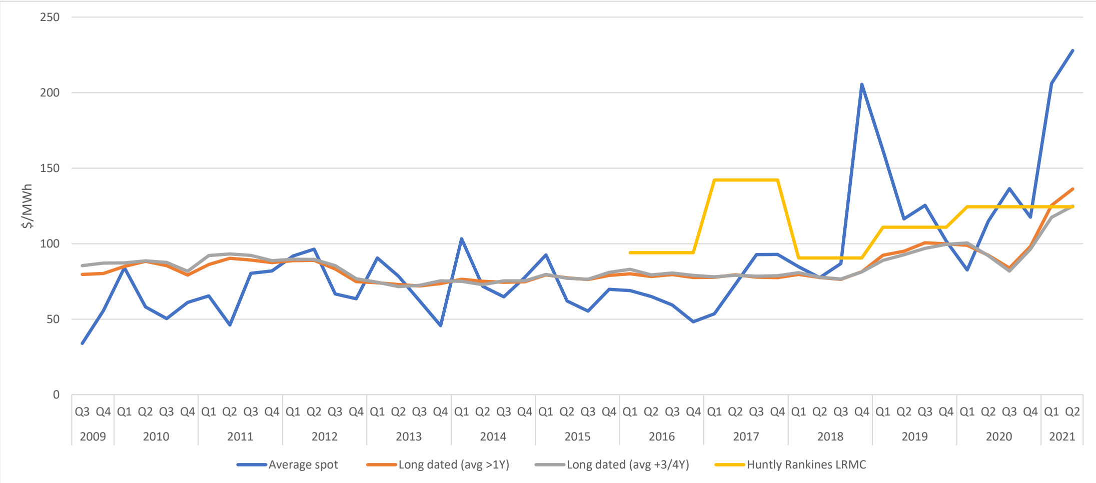
After around 2007 New Zealand's national electricity demand growth rate changed significantly. It went from steady linear growth to not growing on average. As the market had continued to anticipate demand growth, and because power station projects were already underway, a significant surplus of generation was available from 2009 until 2015. As a result, prices stayed soft for a few years, though 2012 was a dry year. As would be expected, low electricity prices lead to rationalisation, and the Southdown and Ōtāhuhu power stations were decommissioned at the end of 2015.

With the removal of the fossil-fuelled thermal capacity in 2015 and a dry period in 2017, prices started to firm and remained higher than they had done over the earlier period. Then the tightening of the gas market from 2018 strongly affected prices, which have been at record levels since.

[14] Described in the Act as "imposing a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including public conservation campaigns)".

The spot price series is shown in Figure 10. Also shown is the Huntly forward-looking total cost of energy (LRMC), which we have assessed from 2016. This is forward looking because it includes no sunk costs, but does include fuel costs, variable O&M, and the fixed cash costs required to retain the units. Also shown are prices of future contracts entered in to well ahead of the contract maturity, i.e. they should reflect the efficient contract price of forecast spot plus a risk margin.

Figure 10: Long dated futures vs spot vs HLY LRMC



From 2009 to 2012 contract prices were higher than average spot prices and were almost equal to our lower assessment of Huntly LRMC, i.e. contracts were recovering fixed costs and encouraged the retention of security of supply capacity. From 2012, when:

- the market easily weathered a significant dry period,
- participants recognised that demand was not going to grow again immediately, and
- the Electricity Authority strongly supported retail competition

there was a perception that prices would continue to be flat and risks would be lower, leading to contract prices moving closer to variable spot prices. Now there was no risk premium and no contribution to fixed costs from contract prices. Under this regime, fossil-fuelled thermal generation exited the market. This is not the first time this has occurred. Competition and the perception of a benign market also led to low contract prices and under-contracting in 2000, then a dry year in 2001 stressed the market and lead to the exit of On Energy, which had been New Zealand's largest retailer.

Once the market tightened from 2017, contract prices lagged spot prices, i.e. they were not reflecting the actual risk, and retailers weren't contracting so much ahead for multi-year risk, e.g. dry period risk. Tellingly, the total cost of energy of the Huntly Rankine machines increased as the two-for-one carbon credit policy rolled off and then ETS reforms pushed up carbon prices. Of course, a lift in the total cost of energy of Huntly Rankines wouldn't lead retailers to believe that risks had also increased. However, as can be seen, the futures contracts weren't pricing in risk. However, few parties, if any, anticipated the level of price increase that occurred from 2018 on.

Generators appear to have been a little complacent about risk as well. The workings of the contract market and its role in the market have undergone a great deal of scrutiny given that:

- even generators don't predict some significant market risks

- retailers have less information than generators
- low prices can be sustained for a long period where the incentives to undervalue risk are strong
- many retailers are too small to justify sophisticated trading teams.

Under the factual scenario of 100 per cent renewable by 2030 with Onslow, as shown in Figure 18, prices will be significantly lower than the low price period from 2009 to 2016 for the majority of years, while high price periods will need to be at least as high as 2021 to date. By 2050, as shown in Figure 19, the high price years will need to be significantly higher again. With no fossil-fuelled thermal available the supply curves will be much steeper than has been the case to date. In the absence of intervention or new market solutions, scarcity pricing is likely to be much more evident in the 100 per cent renewable world, which will put further pressure on the contract market. That could lead to under-recovery of fixed costs for generators in most years followed by extreme market stress in few years.

Conclusion

This would be a classic tragedy of the commons. Acting individually, retailers will have strong incentives to take spot market risk for long periods and either ignore dry period risk or not even understand it. Yet, when a dry season occurs, the resulting prices could bankrupt some and cause severe market disruption, leading to regulatory (political) risk. There could be a case for mandatory insurance.

Can we rely on market-based interventions?

The market-based intervention that can be applied is some form of mandatory security of supply insurance for all retailers. As the mandated requirement would be on all retailers, this would preserve retail competition but at higher prices than will clear in the spot market – equivalent to the LRMC of new security of supply, given set reserve capacity requirements.

In most markets this would take the form of a capacity market, but that is not the best solution for New Zealand's problem. While capacity may become more of a problem in the future, in New Zealand we need firm energy to be available for extended periods during hydrological dry periods. A firm energy market not only encourages investment when needed but also ensures that assets are operated to maximise availability during dry periods. In markets that have similar problems to New Zealand, the solutions have included some form of firm energy market or an operating reserve demand curve (ORDC) rather than capacity markets.

Firm energy market

Generally, a firm energy market puts the obligation on retailers to purchase firm energy contracts to the level and specification determined by an independent party (usually a regulator). This market is the opportunity for those that provide security of supply to secure revenue for fixed costs. Usually, all generators get access to the market to the extent they can guarantee minimum energy contributions over the time periods specified. As a result of the firm energy market, prices in the energy market are expected to clear at SRMC (including water value which is the short run opportunity cost of hydro).[15] Hydro generators may still have high water values in times of shortage but, due to the firm energy market, there is still plenty of competition to clear at SRMC and dispatch firm energy resources.

Operating Reserve Demand Curve

An ORDC is a function added to the spot price calculation. It is similar in concept to our instantaneous reserve market, which solves for instantaneous reserve at the same time as energy dispatch in the market. However, where instantaneous reserve is formed from offers from providers, the ORDC is a predefined curve. The price from the ORDC is set based on the remaining generating capacity available (probably by island) after energy and reserve is dispatched.

It is designed to lift prices to the LRMC of security of supply plant as the operating reserve declines. This function is intended to ensure prices lift to the 'correct' level in times of shortage and, therefore, give confidence to investors. As such there should be sufficient new investment in security of supply plant that prices rise during shortage but otherwise there is always sufficient capacity to otherwise clear at SRMC. Again hydro water values may rise high, but plant with firm energy availability will get dispatched ahead of the hydro plant.

However, there are concerns from the electricity market in Texas, which is similar to New Zealand's and uses an ORDC, that the ORDC approach doesn't work as intended with high levels of wind generation. It is also not clear that an ORDC approach would necessarily ensure firm energy over a dry period, as it is more of a capacity mechanism.

Scarcity pricing

New Zealand's scarcity pricing regime, where shortages of peak capacity activate administered prices, is conceptually similar to the ORDC approach. Potentially, the scarcity pricing approach could be modified to encourage firm energy. However, the same problems may exist as for the ORDC approach where it doesn't necessarily encourage firm energy over dry periods and may not be effective with high levels of intermittency.

Will a market intervention work?

Despite the possibility of above interventions, the market could still fail as a result of two possibilities:

1. The economic options for security of supply convey too much dominance to one or more market participants.

2. Despite the interventions, no party would invest in the most economic security of supply option.

[15] Other forms of storage can also have a short run opportunity cost higher than cash costs.

Market power

Market power is a term that means that a party to a market is able to influence price without losing sales, or where the price uplift compared to the loss of sales is more profitable than committing their full volume. Some market power is accepted in energy only electricity markets during periods of scarcity so that prices lift to the level for recovery of long run fixed costs, which encourages investment in security of supply as described above. Ideally markets should have no market power, so that consumers are paying the least cost for their purchases. However, most markets are not perfect and the term 'workably competitive' is often used to describe markets where there may be market power but the exercise of it is not excessive. This is context-specific; for example, a 100 per cent renewable energy only electricity market that was perfectly competitive in the short run would fail in the long run as prices would never lift high enough to encourage new investment when needed.

There are two key attributes to market power that are equally important from an effective competition perspective: the existence of market power, and the incentive to exercise it. Markets are still considered workably competitive where there is potential for market power to be exercised but it is not exercised. The Electricity Authority has spent a great deal of time trying to ensure that mechanism in the Code disincentivise generators from exercising market power for example.

For this paper the issue is whether the existence, or potential exercise, of market power might be changed with the introduction of a single storage facility into the market. We have not addressed the issue directly but have factored the issue into the default operating model we used for the modelling. This model has, we consider, the least risk of exercising market power mainly because it would prioritise meeting dry year needs over any other objectives and its earnings would be regulated thereby reducing the incentive to manipulate the market.

Best option cannot meet private investment criteria

It could also be the case that the best security of supply option cannot meet investor criteria. For example, the potential Lake Onslow scheme is very large and involves significant tunnelling and civil works. At a nominal cost in the order of billions of dollars, geotechnical risk could make it look too big and too risky to private investors. Similarly, private investors may conclude that the resource consenting issues are too significant for a private investor.

Evidence

The assessment of whether security of supply options would need to be in public ownership is a function of what option looks to have the best business case. An option where security of supply was highly distributed – e.g. overbuild of wind farms, if this can be encouraged using market interventions – could probably be left to private investments, whereby Onslow probably could not.

As a rough guide to the level of distribution of security of supply that might be required for private investment, we use the Herfindahl-Hirschman Index (HHI) to assess the potential for market power in the provision of security of supply. HHI is a measure of market concentration which can be used as a qualified guide for the potential for market power. Generally, a HHI of 2,500 or less is required for a market to be considered moderately competitive.

Assessing a couple of possible and illustrative options, the results are shown in Table 2.

Table 2: HHI assessment of market power in security of supply

Security suppliers	**Current**		**100% renewable in 2030 plus 1 supplier**		**100% renewable in 2030 plus 2 suppliers**		**100% renewable in 2030 plus 3 suppliers**	
	GWh	%	GWh	%	GWh	%	GWh	%
Pukaki	1,600	34.8	1,600	27.8	1,600	27.8	1,600	27.8
Tekapo	290	6.3	290	5.0	290	5.0	290	5.0
Waikato	560	12.2	560	9.7	560	9.7	560	9.7
Huntly	1,100	24.4						
Stratford	1,000	22.2						
Supplier 1			3,300	57.4	1,700	28.7	1,100	19.1
Supplier 2					1,700	28.7	1,100	19.1
Supplier 3							1,100	19.1
HHI	2,500		4,200		2,500		2,000	

This rough assessment suggests that the concentration of market power, if more than 50 per cent of security of supply storage were to be held by one party, would be untenable. Such an entity would need to be under some form of public control or restraint.

One extra (two new suppliers in total) security of supply resource, as long as the storage is evenly distributed between them, should be no less competitive than the current market. Three equal security of supply providers should, subject to other factors such as access to market, be more competitive than the current market. Private investment could be considered for two equal suppliers, and certainly for three or more.

Conclusion

In this section we have highlighted two questions that the NZ Battery project has to consider as context for the business case:

- Will there be sufficient investment in renewable generation, and can the wholesale market still deliver efficient market transactions with the 100 percent renewable electricity supply target and an NZ Battery solution in place?
- Why wouldn't the current electricity market deliver 100 per cent renewable by 2030, and security of supply with equity, transaction efficiency and investment adequacy?

The conclusion around the need for public control or restraint on a security of supply option under the 100 per cent renewable criterion depends on the best option identified under the business case assessment. If the best option identified were to be the concentration of security of supply storage in one entity, then this entity would need to be publicly controlled or restrained. (For this exercise we assume Onslow would be controlled by an independent regulated Crown entity with a clear dry year risk mitigation objective.) If better options suggested two or more equal providers of security of supply providers, then private investment under market mechanisms should be feasible. However, this would have to be further tested with the specific details of the options, e.g. transmission constraints affecting one provider over another may lead to undue market concentration under certain circumstances.

The modelling for different options would, then, need to be different as a publicly controlled or restrained dominant entity is likely to have different market impacts than more competitive options.

NZ Battery – a discussion case

Getting started

We have modelled scenarios as per our brief. We have found it necessary to zoom out and clarify the context that the market would operate in. By understanding that, we can see the tensions that are created by Onslow and which have to be recognised as MBIE works its way ultimately through to a best solution in the business case. A great deal of the tensions and challenges are created by the need to get to 100 per cent renewable in the first instance (at whatever date that inevitable transition occurs). While a government intervention raises further challenges, the reason it is being thought about is that it addresses one of the likely challenges raised by the move to 100 per cent renewables – security of supply. The modelling outputs provide quantitative answers to some of the questions, but the analytic framework also provides MBIE a way to think about the problems holistically.

Overview of the analytic framework

Figure 11 and Figure 12 tease out the analytic framework for the current market without fossil-fuelled thermal (the counterfactual) and for the market where a Crown-owned NZ Battery solution is created. We base the modelling on the potential Lake Onslow pumped hydro storage scheme, as the early evidence is that this is the most accessible solution if the 100 per cent renewable market fails to deliver security of supply at least cost. We revisited this framework once we saw the early results from modelling because the risk of failure to supply in the North Island came through clearly in the modelling.

Figure 11: Analytic approach to understanding the "current market" i.e. in 2030

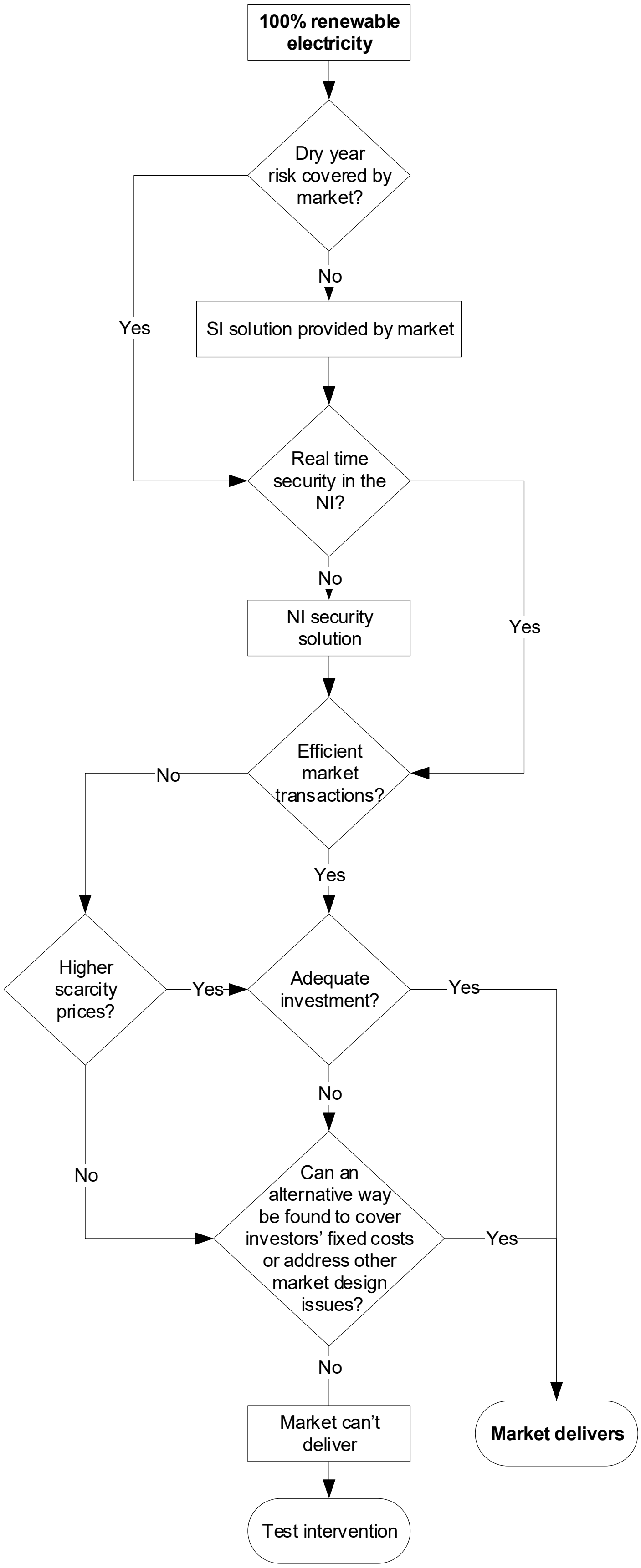
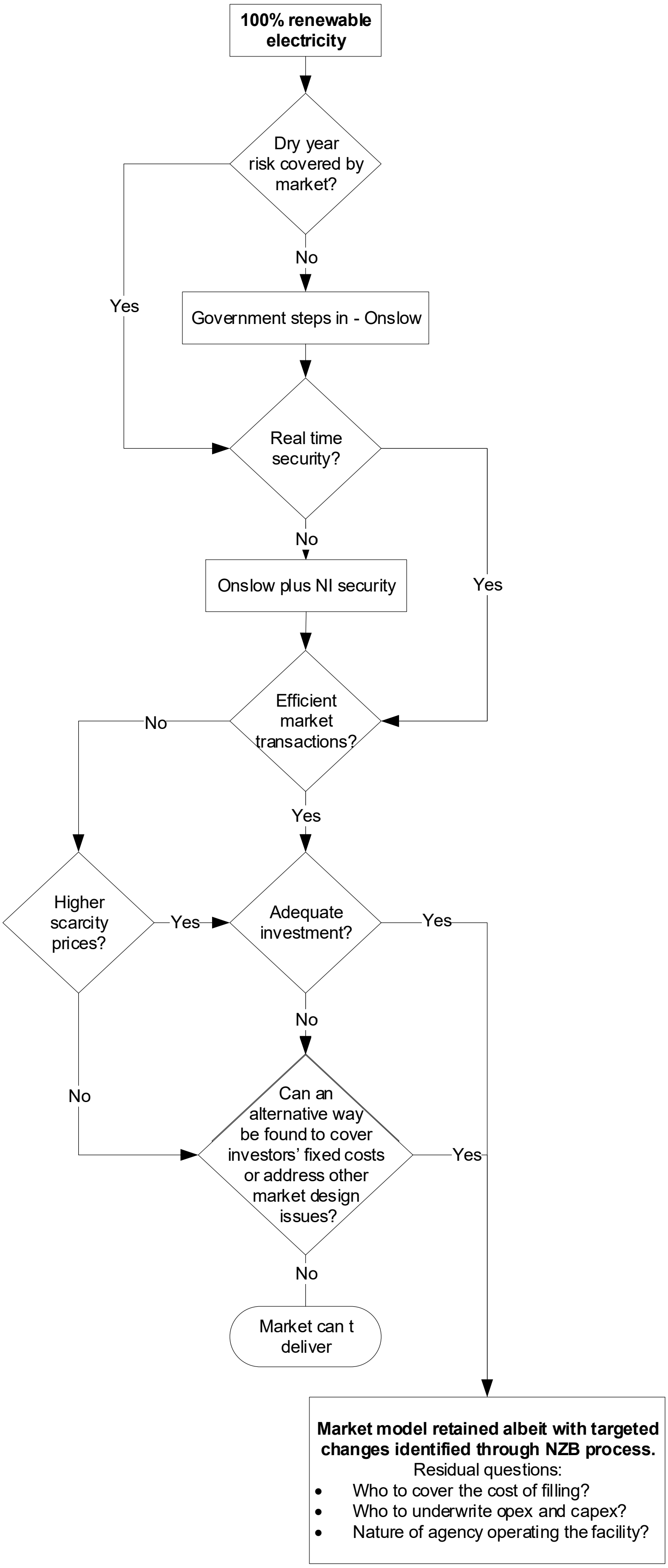


Figure 12: The analytic approach to understanding the current market with Onslow added in using our assumptions for the operational model



Dry year risk

We use the terms 'security of supply' and 'dry year risk' interchangeably. This is the requirement for large volumes of energy to make up a deficit of hydro generation which may last several months. It is not time-of-day specific; it is sufficient to provide volume day by day to firm other generation sources.

Real time security

In this paper, real time security is the risk of non-supply at a particular time. That might be a cold, dark calm winter peak or when a generator fails or the HVDC is constrained.

Efficient market transactions

Efficient market transactions include price formation in the spot market reflecting scarcity of supply when it should and stimulating investment where prices exceed the LRMC over time on average. There is a presumption that market power is dealt with by the market regulator. W we chose an independent entity, regulated for cost recovery only, operating continuously on the basis of a water value approach for our modelling because we think this model will have the least risk of a market power problem.

Efficient market transactions include a thriving forward market. It is possible that the NZ Battery operator offers dry year contracts as part of its activity, but obviously this could not be at the expense of its preeminent operating objective.

Higher scarcity prices

With no fossil-fuelled thermal setting prices in the dry year role and the peaking role, the supply curve may be much steeper than is the case currently. In the absence of interventions or changes in market design, scarcity prices would become a bigger feature of wholesale prices, and some thought may have to go into what is acceptable for the level of prices that signals scarcity. If those high prices are suppressed, that would raise the risk of underinvestment.

Adequate investments

Adequate investment is critical for the success of the market. Investment is required to replace fossil-fuelled thermal generation, meet increased demand from decarbonisation, contribute to security of supply and contribute to real time security.. If a scheme at Lake Onslow went ahead there would also be the need for gernation to fill the dam initially and after events.

Alternative ways for investors to cover fixed costs or address other market design issues

If the workings of the market do not yield spot prices or forward prices that encourage investments or if other issues arise from the 100 per cent renewable policy, there may be ways the market design can be advanced to create incentives or deal with other problems. This paper is not intended to address the problems. It is to provide a first look at a context for understanding how all of these issues fit together.

Residual questions

These are the questions our analysis does not address but which will have to be addressed if the case for an intervention is made.

Operating models

In order to understand *the potential market interactions or effects which MBIE will need to consider when completing the evaluation of options to address the dry year problem or issue* we have to understand:

- the mandate the organisation interacting with the market has, and
- the objective function the organisation's traders apply when they are interacting with the market.

When thinking about the possible operating model for NZ Battery, there will be a number of characteristics to work through, including:

- level of independence from the Crown
- operational settings
- revenue or profit objective
- price setting.

For each of these there will be a range or spectrum of possibilities.

For example, the possible independence settings could include a spectrum from Crown control, to Crown entity, to SOE, to bespoke statutory framework guaranteeing independence (such as the Reserve Bank), to private ownership.

The range of operational settings could be from:

- Onslow is held full and generates only when dry year criteria are met; to
- Onslow is able to pump (consume electrical energy) and generate (produce electrical energy) as the operator sees fit. This would leave the operator free to operate half hour by half hour in the market. The operator could also enter into bilateral contracts including, mainly, dry year or firming contracts. The operator could be required to provide dry year risk contracts.

Revenue or profit settings could range from:

- not-for-profit / cost recovery, to
- revenue / profit maximising subject to independent regulation, to
- unregulated pursuit of revenue / profit.

Resolving the revenue or profit settings will still leave choices to be made on how NZ Battery should set prices.

We assume, given the scale and potential market power of NZ Battery, that revenue or profit settings will be at the cost recovery or regulated end of the spectrum of choices rather than unconstrained pursuit of profit. But even where revenue or profit is regulated, on say a one-year or five-year basis, that still leaves considerable room for choices to be made about how to set prices.

It seems self-evident that if an NZ Battery solution were to be built, its preeminent priority must be dry year risk (security of supply) at all times, regardless of what other objectives might be taken into account. This would be the primary objective guiding price setting. As discussed below, an operator of Onslow charged with pricing in a way that maximises the security of supply objective would set prices by reference to water values. The regulatory and governance regime would need to rise to the challenge of assessing ex post how well the operator performed that task.

Given the potential scale of NZ Battery in the electricity system and the fact that it would be set up to exercise judgment to advance the public policy objective of security of the system, there is the potential for the analogy of the Reserve Bank to illuminate some of the choices to be made in establishing NZ Battery, in its independence, articulation of a primary objective of security of the system, and potential for secondary objectives where they don't detract from the main mission.

The final model would have to be tested against some criteria. For example, for a given model, does the market:

- meet security of supply requirements?
- meet real time security requirements?
- support efficient market transactions?
- encourage sufficient investment?
- achieve an equity policy objective?

We have not modelled Onslow's financials because we don't know what the capital cost or operating costs would be. As a result we can't assess whether its revenue will be sufficient or whether there would be a net cost that requires underwriting. If there is a net cost, those could be met from taxes, levies, or a charge set against generators along the lines of the current HVDC charge. We haven't needed to address the level of costs or the approach to cost recovery for the modelling. For this report the only point we have to make is that a levy approach to cost recovery would alter the distribution of price outcomes from the modelling.

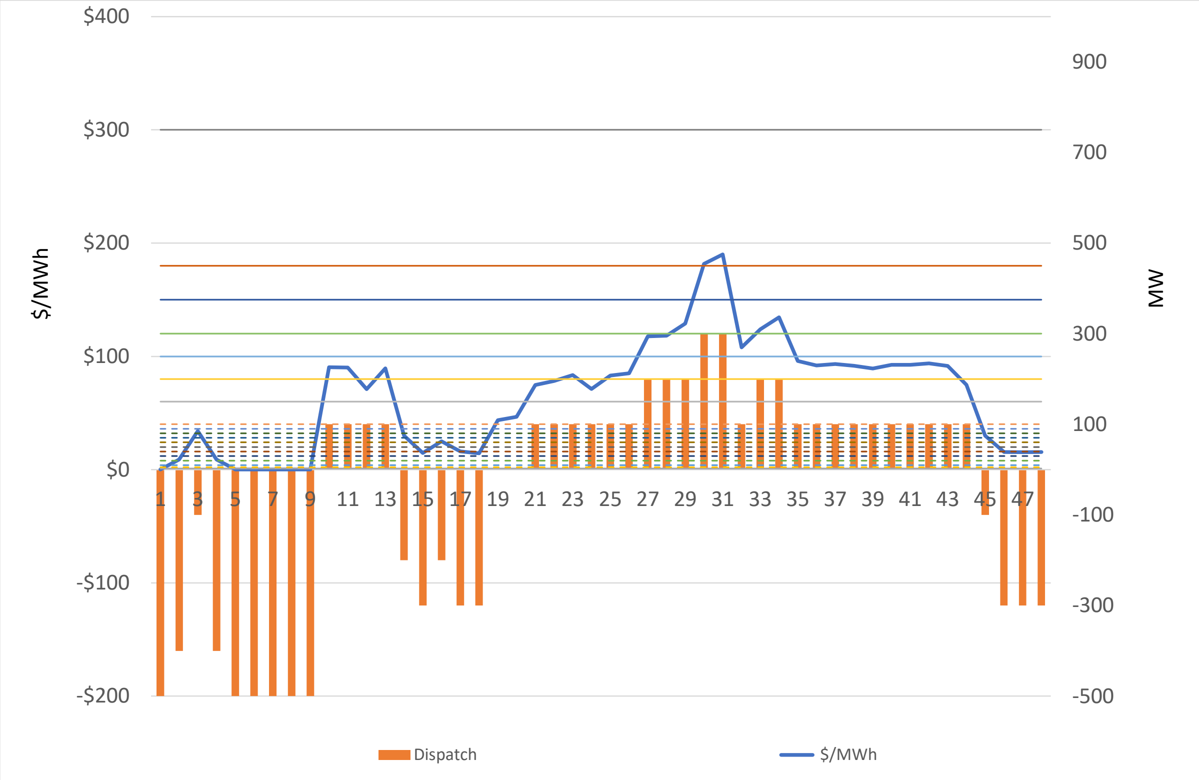
How continuous operation would work

Figure 13 illustrates how an operator at Onslow might set up their offer. This informs how Onslow would integrate into the market. Periodically, say weekly, the target average purchase (for pumping) and sales (generation) prices would be developed based on a water values approach. If the operator was a not-for-profit independent agency, the difference between the annual average target prices would reflect the preeminent objective of managing dry year risk followed by the efficiency loss between pumping and generating and any other permitted (regulated) ability to earn net revenue from the scheme.

The horizonal lines in the chart show the prices that 100MW tranches are offered and bid at progressively. If this approach were adopted it would mean that the entire pumping requirements or generating ability isn't brought into the market at one time. For this example the orange bars show the MW of pumping and generation through the day at the given prices.

No account has been taken of the impact on price outcomes that the presence of Onslow would have. In this case Onslow would have consumed 3,100 MWh pumping and generated 1,850 MWh for a net revenue on the day of $88,572.

Figure 13: Stylised Onslow offer and illustrative outcome 02/02/2020



Contracting

Contracts could be a method for recovering fixed costs for NZ Battery and could also form the basis of a firm energy market. An original market design for the New Zealand Electricity Market had considered using obligations on retailers to purchase option contracts to cover their capacity risk as a capacity market. The same mechanism could be used for a firm energy market.

To recover costs and manage its primary objective, NZ Battery could look at many contract structures, for example CFDs. If NZ Battery were to underpin a firm energy market, then some degree of optionality would be ideal. Options or swaptions contracts have no impact on the spot market until the option conditions are met. This could be to incentivise NZ Battery to operate to cap prices, or to incentivise it to run under defined hydrological conditions.

NZ Battery is also suited to offer collar contracts where purchasers would ensure NZ Battery gets a minimum price when prices are low in return for NZ Battery capping prices when prices go high. NZ Battery works a bit like a physical collar on the electricity market, lifting low prices and lowering high prices.

Having contracts will change the incentives on NZ Battery, as shown in Figure 14, but the incentives from these derivatives put the obligation on the NZ Battery operator to cover other party's price risk; the operator must either generate to cover the risk or purchase from the market. Even with contracts, the NZ Battery operator will still use the opportunity cost of storage, e.g. water values in the case of pumped hydro, as the cost of operating in the market and responding to contracts.

Figure 14: Workings of hedge contracts

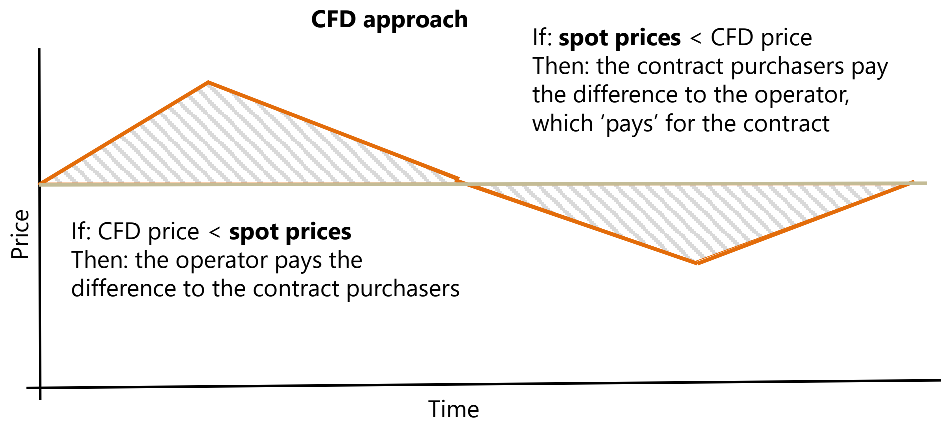
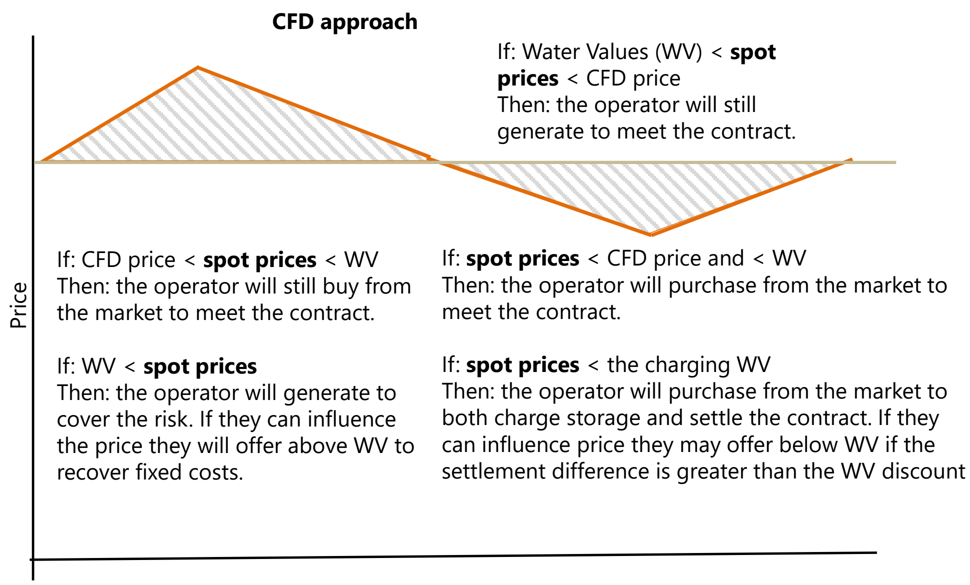


Figure 15: How contracts change market participant incentives



The operator of Onslow could offer hedge contracts to recover fixed costs as long as the activity didn't undermine its preeminent objective of managing security of supply. If NZ Battery were used to underpin a firm energy market, then this objective would be explicit in the contract obligations and form.

The simplest way to implement a firm energy scheme would be to require market participants to purchase contracts for the term of the defined dry period from NZ Battery in proportion to their assessed need for firm energy. This method is most attractive for the investors in NZ Battery as it guarantees some fixed cost recovery.

However, there are good reasons why the investors in NZ Battery should take investment risk, i.e. open the firm energy market up to competition. Under this method the requirement on market participants would be to purchase a defined level of approved firm energy contracts for the defined dry period. Participants would be allowed to purchase from anyone who met the firm energy contract specification. Participants could also meet their requirements from multiple parties over the term. This approach would allow the most innovation and would have the least impact on the market from the presence of NZ Battery. NZ Battery would effectively become a safety net. It would be pointless for investors to consider schemes and firm energy contracts that are more expensive than NZ Battery, and there would always be sufficient firm energy to meet dry period risk.

The operating model we have used in our analysis

In Figure 16 below we set out a matrix of possible entity styles and active regime approaches. We suggest five criteria for assessing each combination and permutation of operating entity and operating modes.

For this report we have modelled an independent regulated entity operating 24/7 in the market basing its pricing on water values. These results provide a starting point for the development of the initial scope and assumptions for the business case evaluation for the NZ Battery project – specifically how any NZ Battery project will interact with and affect New Zealand's current electricity market – as per our brief.

Figure 16: Illustration of how options for NZ Battery operating models would be tested and some criteria that could be used. The default operating model adopted for this analysis is highlighted.

Onslow status / Operating entity	Active regime	Meets security of supply requirements	Meets real time security requirements	Supports efficient market transactions	Encourages investment	Equity
Crown entity	Dry year operation only					
	Hybrid					
	24/7 continuous operation					
Regulated independent entity, dry year priority – pricing in market based on opportunity cost	Dry year operation only					
	Hybrid					
	24/7 continuous operation	We have based our modelling on this option using a water values approach				
Non regulated profit maximising	Dry year operation only					
	Hybrid					
	24/7 continuous operation					

Once the modelling results are digested and the operating model options, operating modes, pricing approaches and criteria are refined, the options represented by the individual cells can be considered.

The modelling

Introduction

Modelling of the electricity market was undertaken to test the impact of Onslow on the electricity market as it is likely to be in both 2030 and 2050, on the assumption that generation is 100 per cent renewable by 2030, i.e. that there are none of the current fleet of fossil-fuelled thermal generators remaining in service by 2030.

Demand is expected to grow by 2030 and even more so by 2050, as the economy decarbonises and fossil fuels are phased out by improvements in energy efficiency or replacement by electricity as an energy source. For example, by 2050 the light vehicle fleet is largely expected to be comprised of EVs[16] and industry is expected to have replaced fossil fuels for raising heat with electricity. In the latter case, it might also be that green hydrogen replaces gas in many applications, with electricity required to power electrolysers to produce the hydrogen.

Our approach

In both 2030 and 2050, the market was modelled initially without Onslow, with only enough new plant built so that each achieves its target return on investment (RoI),[17] more or less, in the year of interest. To build more new plant than this would depress prices, causing new generation to fall short of its target RoI, and to build less would see new plant recovering greater than target RoI, neither of which is likely, on average, in a competitive market.[18]

But this test for new plant building is not an exact test. In the real market, prices might turn out higher or lower than expected. In the modelled market, it is simply not possible for all new plant to simultaneously achieve its exact target RoI, so the test for a 'balanced build' is that new plant is, on average, close to achieving target RoI in the year of interest. An additional complication is that new grid-scale projects are large, and there can be periods when adding one new project reduces RoI below target for all new plant, but without that one project, target RoIs are exceeded for all new plant: hence some judgement is required as to when sufficient new plant is built.

Geothermal plant tends to outperform wind and solar farms because it runs baseload, so it gets the advantage of price spikes that occur when wind and solar output is low, e.g. on cold, calm winter evenings. But there is a relatively small supply of new geothermal plant, whereas wind and solar farms have a much greater supply and will be required in significant number to satisfy demand in 2050.

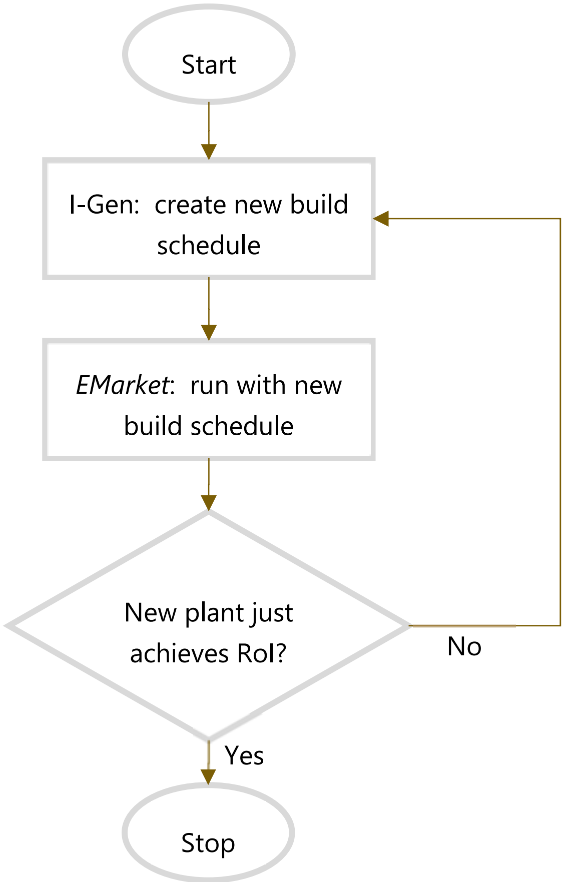
There are two models involved: I-Gen[19] and *EMarket*. I-Gen works out which plant to build and when, with the list of new plant known as a 'build schedule', whereas *EMarket* models the market including the new and existing plant. This configuration is ideal for this exercise where the question of adequate

[16] Primarily battery electric vehicles.
[17] The test is actually performed on target EBITDAF, which includes cash RoI.
[18] After 2008 we saw a period of years when demand was expected to follow its long-term growth path, and a lot of new capacity was added through to 2014. However, the growth rate of demand fell dramatically after 2008, and the end result was a surplus of capacity.
[19] It is planned to integrate I-Gen into *EMarket*, but currently the two models are separate.

generation investment is critical to Government's policy objectives for the sector. It allows us to calibrate the generation build then test to see if security of supply and security is achieved.

There is an iteration between I-Gen and *EMarket* as shown below.

Figure 17: Creating a final scenario



I-Gen has inputs which allow it to calculate the levelised cost of energy (LCOE) of each potential new project. LCOE is equal to the constant average annual electricity price attained by the plant over its lifetime that just achieves target RoI after covering all cash costs. In simple terms, if a project reaches a point where its forecast GWAP[20] exceeds its LCOE, then it becomes a committed project and starts construction.

The emphasis in the modelling was on exploring market impacts, rather than on creating, to the extent possible, models of 'perfectly built' markets, because achieving these could hide potential negative impacts on the market or hide the potential for instability. For this reason, the iterations shown above were not taken to the point where a perfect solution was attained. It was also observed that in 2050 the high frequency of occurrence of DSR and SLR dispatch caused prices to become highly sensitive to small changes in the build schedule, and also to assumptions around how much

[20] Generation-weighted average price.

short-term battery storage and capacity was available; on the latter point, for example, a key uncertainty is how much EV battery capacity will be available to supply the market, and at what cost.

The forecast GWAP must be calculated carefully because it is a function of a project's location on the grid and its output profile. For example, the output of windfarms in New Zealand, on average, correlates negatively with price, so the ratio of a wind farm's GWAP to the TWAP at its GIP is less than 1. There is no standard definition for this effect, and it goes by the name of 'GWAP/TWAP', peaking factor or market premium, with the latter defined as GWAP/TWAP -1. For wind farms, the market premium is less than zero and currently averages about -10 per cent, though over time it is expected to fall further as more windfarms are added.

The solar market premium is currently greater than zero, but will fall over time as more solar depresses summer prices.

Geothermal generation is baseload, so its market premium is close to zero.

The Supplier of Last Resort (SLR), which partly takes the place of fossil-fuelled thermal peaking generation, has a large positive market premium.

The final run in *EMarket* uses existing generation, less (forced) retirements, but with new plant commissioned according to the final build schedule from I-Gen. A run for 2030 or 2050 consists of 89 runs of this year but with a different historical inflow sequence each time, starting with inflows from 1931 and ending with inflows from 2019: 89 inflow years in total.[21]

To obtain a realistic spread of storage outcomes, the final *EMarket* run was also iterated a couple of times, taking final storage for each inflow year and using this as the starting storage for the immediately following inflow year in the next *EMarket* run. This gives a spread of starting storage values, thus we capture the impact of, for example, consecutive dry years or consecutive wet years. There is a limit to this approach, however, as it will not fully capture the impact of more than two consecutive dry years, and it cannot be used to stress-test the market using multiple dry years. But the spread of storage trajectories actually used was sufficient to allow market impacts to be assessed without skewing results.

EMarket was run in three-hour mode, giving a total of 2,920 steps in each inflow year. *EMarket* can run down to the half-hourly level, which matches the granularity of the spot market, but this would require run times of around nine hours. Three-hour mode achieves a good balance between model run times and the need to model the ability of the market to meet peak demand.

The core elements of *EMarket* are listed below.

1. A grid consisting of 220 nodes and around 290 transmission lines: this provides enough detail to allow accurate calculation of power flows and losses on the grid including the high voltage DC (HVDC) link that connects the two main islands, along with accurate nodal spot prices.

2. Detailed modelling of major hydro systems including large storage reservoirs, head ponds, individual generating stations, minimum flows and water values.

[21] Mean inflows is also run as a scenario, so each run actually has 90 inflow scenarios.

3. Detailed modelled of wind and solar farms, including use of historical wind speed data for wind generators back to 1980.

4. Detailed modelling of geothermal generation.

5. Full modelling of the process of generators submitting offers to the System Operator.

6. Full modelling of the dispatch process and the process of calculating the final spot price used for settlement.

7. An internal programming language that is used for a variety of purposes including modelling scheduled maintenance of large generating plant.

EMarket can run with the thermal rating limit constraints active on all lines, thus capturing the pricing and dispatch effects of network congestion, but this can slow runs down significantly for little value. We used our usual approach, which is to enforce the HVDC limits and, since Tiwai is not included in either year, the post-upgrade limits between the Clutha and Waitaki valleys.

What the modelling is not

The focus of this report is the impact on the market of Onslow, or a similar large battery, intended to ensure that SoS is preserved with once it is added to the market after the move to 100 per cent renewables supply. We undertook enough modelling to allow us to understand these impacts, but this did not require the modelling of a fully developed 100 per cent renewables market. For example, and as noted above, the build schedules were not iterated to a fully converged solution. That being said the market models a lightly dystopic market for the purpose of highlighting potential negative impacts.

Since the modelling is market modelling, it reflects the dynamic processes inherent in the electricity market; it is not a technical optimisation of SoS or security.[22]

Furthermore, we did not systematically seek to determine which, if any, aspects of the current market design might need to change, and how, to sustain a market of 100 per cent renewables. However, where the modelling showed that the current market design may struggle or fail, then we have noted this in the discussion and conclusions.

How do we know that Onslow solves the dry-period problem?

It is not a given that a large storage battery such as Onslow is required to maintain electricity supply during dry periods. From a purely technical perspective, if enough renewable generation capacity were to be built, then there could be sufficient capacity to always meet demand. But to achieve this would require a substantial 'over-build' because renewable generators such as windfarms and solar farms cannot be relied on to produce energy; they rely on wind and sun.

During a dry period, when hydroelectric generation is reduced, the additional capacity would provide the additional energy.

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[22] By this we mean that dispatch is based on prices as per the market design and not on the physical capability of plants.

But there is a particular problem that occurs on cold, calm winter evenings when the sun has set and demand peaks: in these cases, solar generation is zero and total wind generation may be very low indeed. Something is required to fill the gap, and that 'something' is generation that can be relied on to produce energy, including geothermal generation, biomass-fuelled generation, other forms of renewable generation, batteries, demand-side response (DSR) and supply of last resort (SLR).

Batteries in this context means any source of stored electrical energy provided into the market for reserve duties. They have high capacity but low overall storage, so they charge during off-peak periods when prices are low, and discharge (generate) during peak periods when prices are high, with the charge-discharge cycle being quite short-term, typically between one and several days. The battery capacity could be supplied by grid-scale batteries or by small-scale batteries that sell power back to the grid, and these could be in EVs, houses, businesses, or they could be attached to generators such as wind and solar farms.

DSR represents demand that is contracted to turn off when the price reaches certain thresholds, and it is modelled by DSR generators that offer at between $2,000/MWh and $8,000/MWh, with total of 100 MW in 2030 and 150 MW in 2050. To qualify as DSR, the response must be firm, in the sense that it has contracted out of any discretion as to whether it can be dispatched off at any time.

SLR is priced at $10,000/MWh which is the value that is currently specified in the Code as the lower end[23] of the price that will be set when there is a shortage of generation offered into the market relative to actual demand. The assumption here is that SLR would be offered at or just below $10,000/MWh and it could represent very expensive generating capacity that operates infrequently, or ultimately it could be non-supply.

Without a large battery such as Onslow, which has seasonal storage, the over-build is required to ensure SoS and security, to the extent possible. But with Onslow in the market, even though it may solve the SoS problem, some over-build may be required to ensure security. If Onslow contributes to SoS and to security, then the over-build might reduce even further once Onslow is added to the market.

Nevertheless, the basic test that Onslow makes a substantial contribution to the dry-period problem is that its presence in the market reduces the over-build to the extent possible, while still preserving SoS.[24]

[23] In a scarcity pricing situation, prices are scaled so that the GWAP in the affected island sits between $10,000/MWh and $20,000/MWh. If the GWAP is initially less than $10,000, then all prices are scaled up until the GAWP equals $10,000. If the GWAP is initially greater than $20,000, then all prices are scaled down until the GAWP equals $20,000. There is a 'safety valve' that operates if the average price remains above $1,000/MWh for a week.

[24] The full list of assumptions is contained in Appendix A.

Results

The main modelling results are shown in Figure 18 and Figure 19. In both cases the sequence of modelling runs progresses from left to right across the page. The 2030 result shows the modelled equivalent with no intervention to force 100 per cent renewables as the first scenario for comparative purposes.

For both 2030 and 2050, a market with 100 per cent renewable supply was first modelled without Onslow. Onslow was then added but without adjusting the build schedule. Subsequently, the build schedule was recalculated with Onslow. The charts below show the results of this process for both 2030 and 2050.

Figure 18: Summary results for 2030. ICCC 100% renewable electricity base case with Onslow added and then capacity reduced to balance the system. Risk of average non-supply in the North Island is also shown.

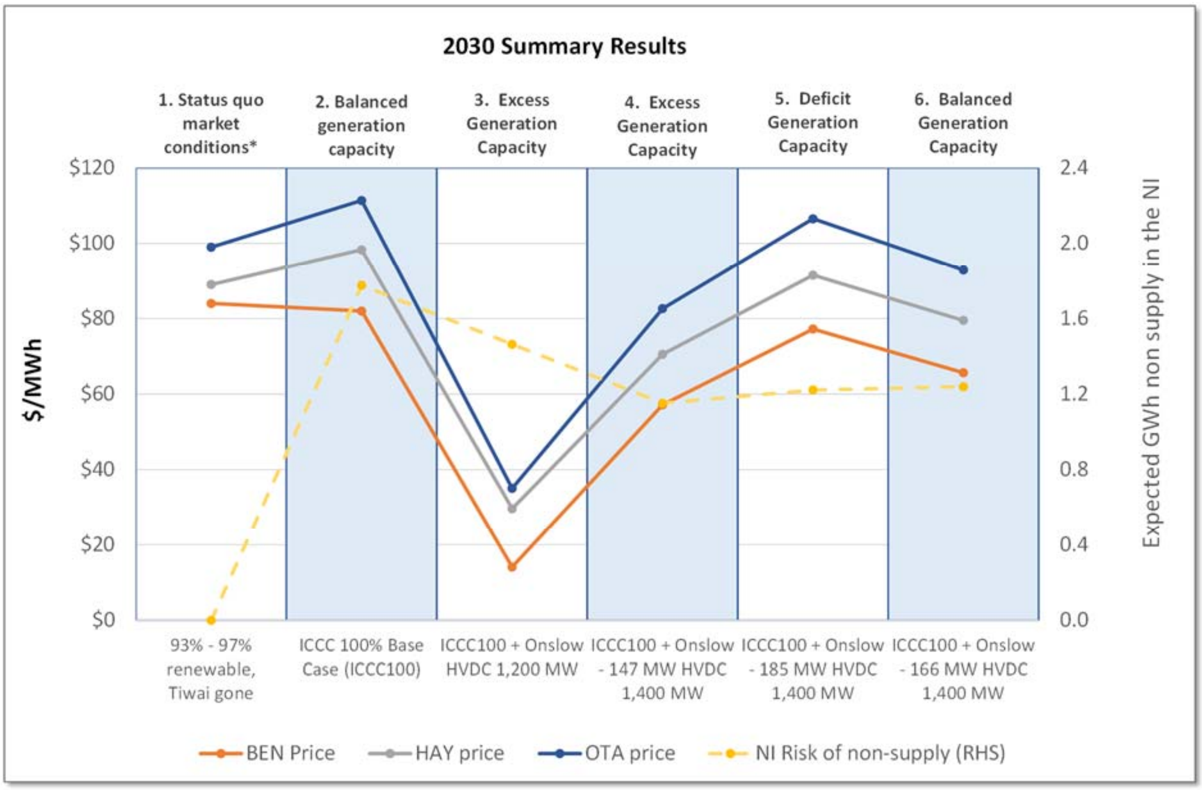
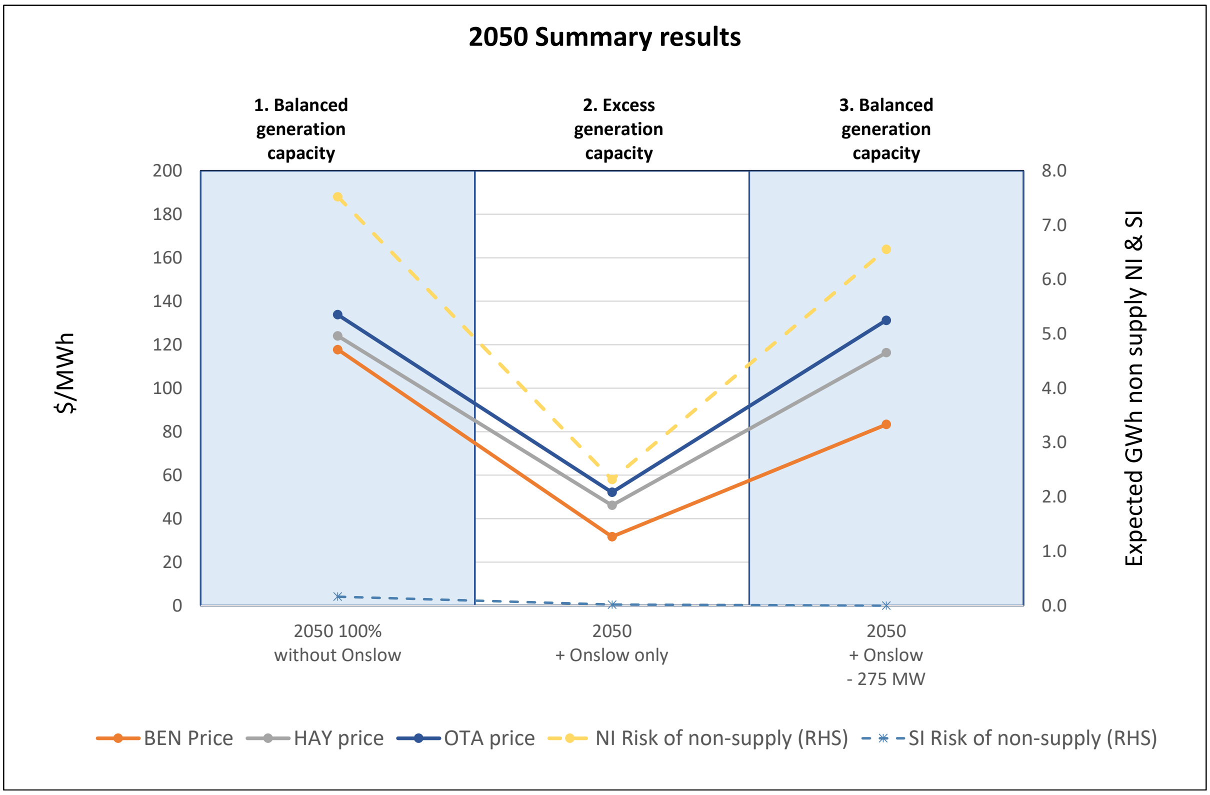


Figure 19: Summary results for 2050. ICCC 100% renewable electricity base case 2050 with Onslow added and full electrification demand. Risk of average non-supply in the North Island and South Island shown.

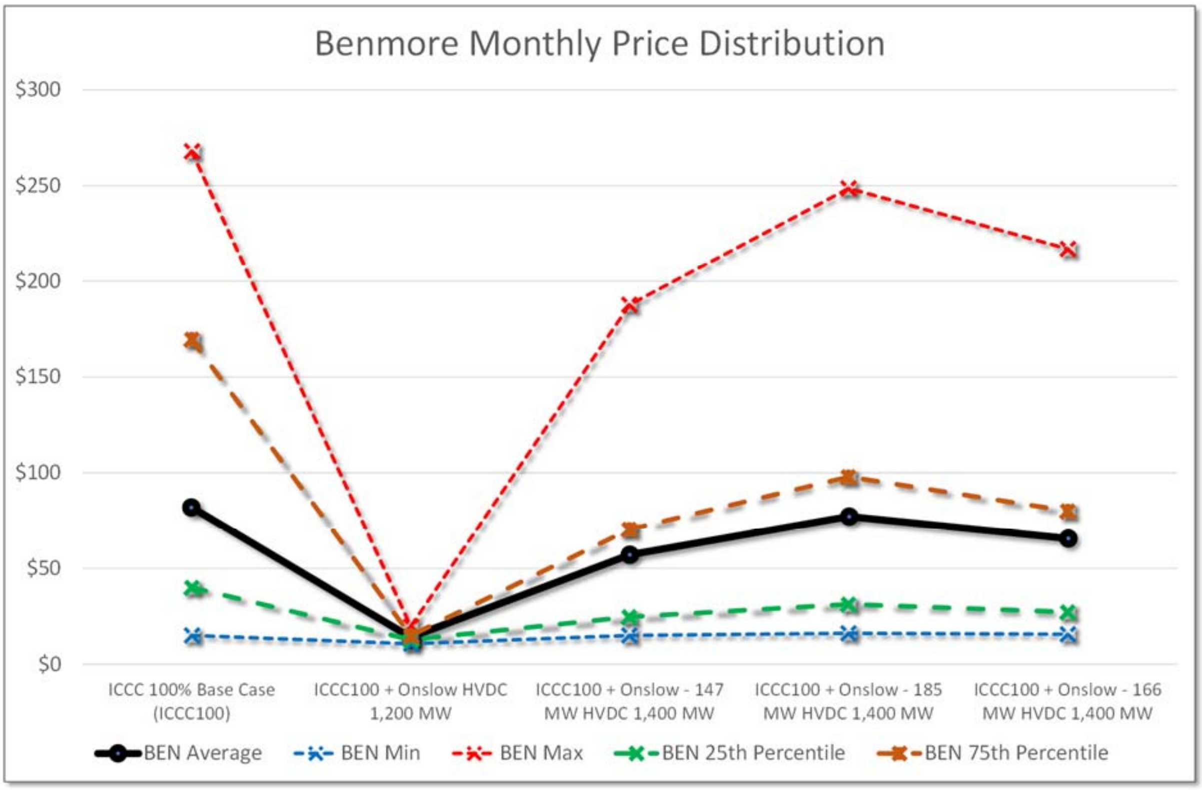


Relative to the starting case of 100 per cent renewables without Onslow, adding Onslow without adjusting the build schedule results in the price falling substantially, and new plant fails to achieve its target RoI. The average DSR and SLR dispatch falls to zero in the South Island, and they fall in the North Island, but remain greater than zero.

Once the build schedule is adjusted so that new plant is once again achieving RoI, the total capacity of new builds in 2030 falls by 166 MW in 2030 and 275 MW in 2050. In 2030 the price with Onslow falls overall, by 20 per cent at Benmore, 19 per cent at Haywards and 17 per cent at Ōtāhuhu. But in 2050 it falls by 29 per cent at Benmore but by only 5 per cent at Haywards, and at Ōtāhuhu it hardly falls at all.

The volatility of prices also changes as Onslow is added and the build schedule is adjusted, as illustrated in Figure 20 below, which shows the average monthly price at Benmore in 2030, along with the minimum, maximum, 25th percentile and 75th percentile monthly prices in each scenario.

Figure 20: Distribution of Monthly Average Prices at Benmore



Initially, when Onslow is added without adjusting the build, monthly average prices converge almost to a single point, with the difference between the maximum and minimum being only $9/MWh, reflecting the surplus capacity.

But then removing plant causes the monthly price distribution to widen again, but once the build is fully adjusted, after removing 166 MW of capacity, the overall volatility is lower with Onslow than without; for example, the 75th percentile price is $80/MWh with Onslow versus $170 without Onslow, and the maximum prices is $51/MWh lower with Onslow.

Similar changes in the monthly price distributions occur across the grid in 2030.

In 2050, the market as modelled is under more stress in the North Is and as a result the impact on the monthly price distribution is not as pronounced as it is in 2030.

Figure 21: DSR and capacity factor of new windfarms in 2030

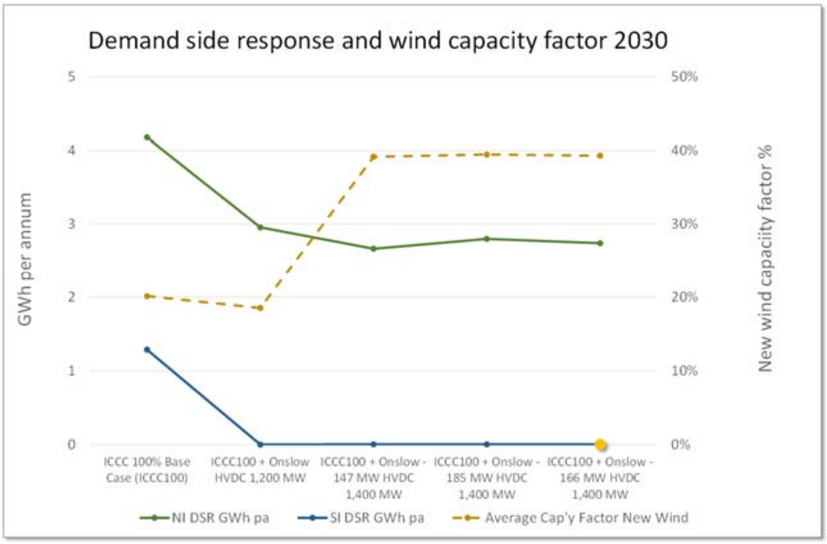
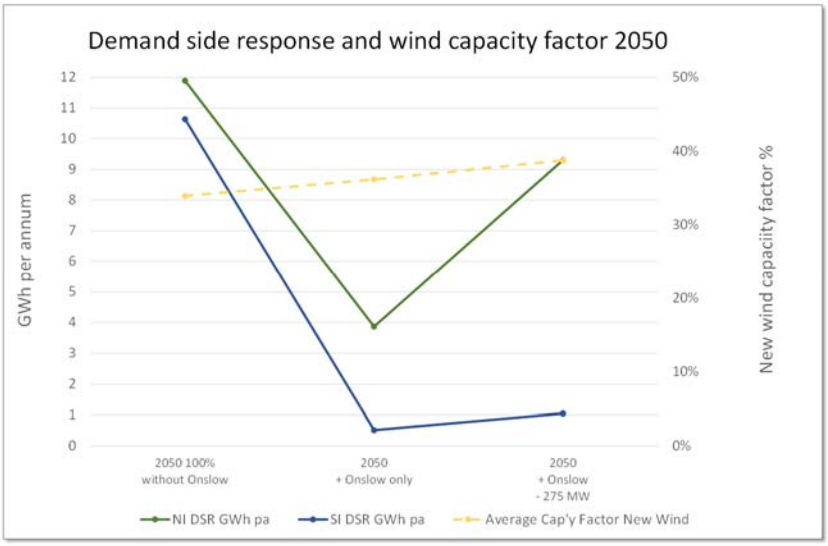


Figure 22: DSR and capacity factor of new windfarms in 2050



The capacity factor of new windfarms without Onslow is well below what it would ideally be in 2030 and in 2050, reflecting the over-build required to achieve SoS and security, but when Onslow is added and the build schedule adjusted, the capacity factor comes up again. This occurs because the presence of Onslow reduces the overall amount of over-build in the market: Onslow generates to provide security in place of the generation not built. But even with little or no over-build, when there is surplus energy available which would otherwise be spilled from wind and hydro generators in particular, it can instead be used to charge Onslow.

The impact on price of small changes in capacity has proven to be significantly greater with 100 per cent renewables than it is currently when modelling the market with the existing fossil-fuelled thermal fleet, and particularly sensitive in 2050. This can be attributed to the high offer prices attached to DSR and SLR, so that small changes in the dispatch of these creates large changes in average GWAPs.

Figure 23 below shows prices averaged by month over all 89 inflow years for both 2030 and 2050 with Onslow, and the key feature to note is the price separation between Benmore and Haywards, which occurs because the HVDC link constraints northward. Another consequence of this is that DSR and SLR are required in the North Island, despite the presence of Onslow, to meet peak demand on calm, cold, dark winter evenings.

Figure 23: Monthly average prices 2030 and 2050

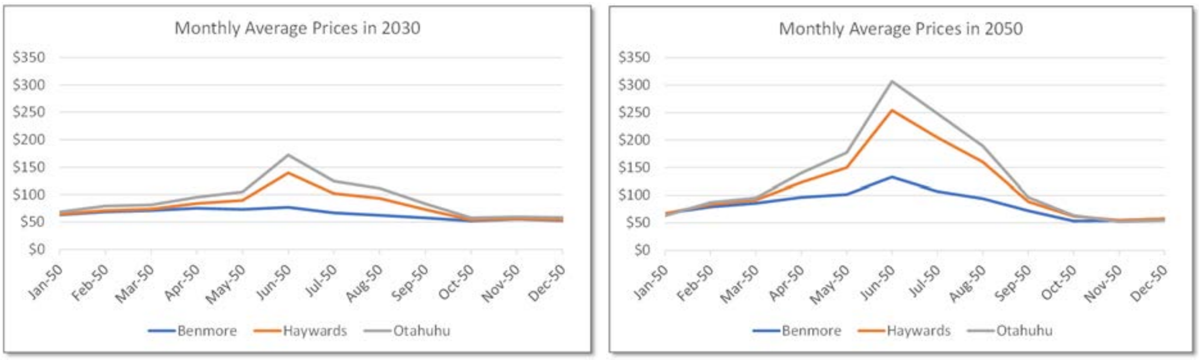
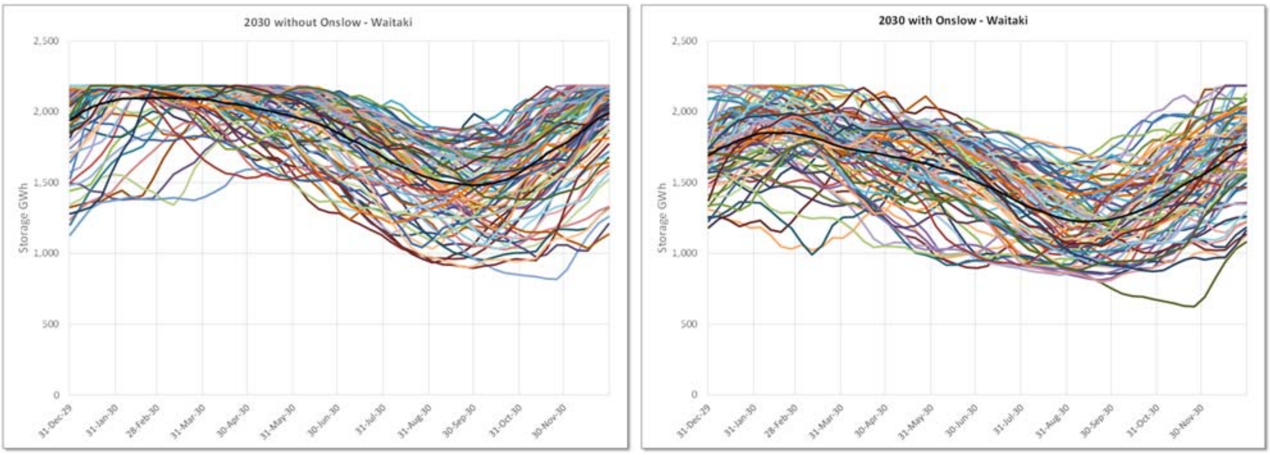


Figure 24 below shows the 89 Waitaki inflow scenarios with (right) and without (left) Onslow. Without Onslow, the water values act to draw storage higher over summer so that the there is greater storage available to go into winter. Whereas, once Onslow is added, Waitaki can be allowed to run lower over summer, reducing spill, and lower overall.

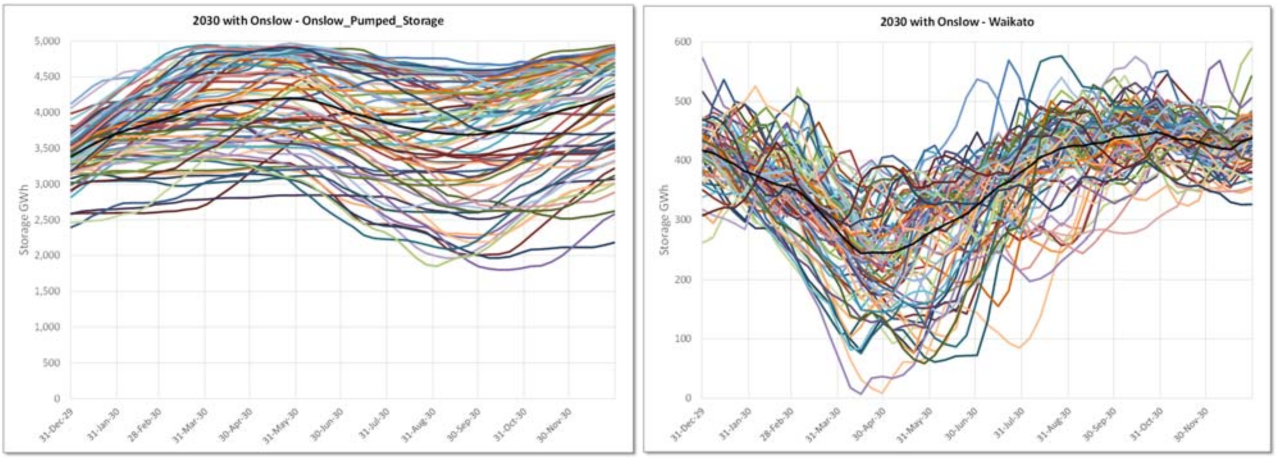
Figure 24: Waitaki storage in 2030



The storage in Onslow itself, shown below for 2030, shows the pattern suggested by the water values charging in summer and discharging through winter. Note that the storage is not fully converged, in the sense that the starting storage for each inflow year should be the ending storage for the previous year. However, the convergence is near enough for the purposes of this report.[25] The storage in Lake Taupō (Waikato) is also shown and it follows a pattern similar to the without-Onslow case, except that it draws lower on average in winter.

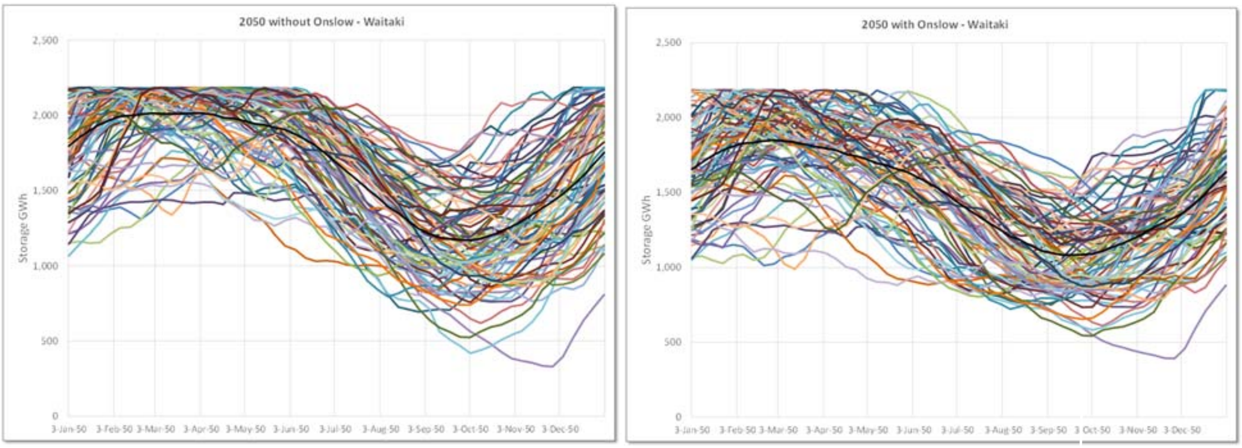
[25] In this case, ending storage is higher on average than starting storage, which means that charging is more prevalent than generating. The only impact of this on the results and conclusions, is that the net revenue obtained by Onslow from charging and generating is negative on average. In all other respects, all inflow sequences have ample storage in Onslow to allow it to respond to dry periods as they develop, and to assist in maintaining security.

Figure 25: Onslow and Waikato storage in 2030



Overall, the addition of Onslow in 2030 takes a lot of 'stress' off Waitaki. However, 2050 paints a rather different picture. Storage at Waitaki, shown below, is assisted by the presence of Onslow, but it now falls into the Waitaki contingent zone below 500 GWh in two scenarios without Onslow and one with Onslow.

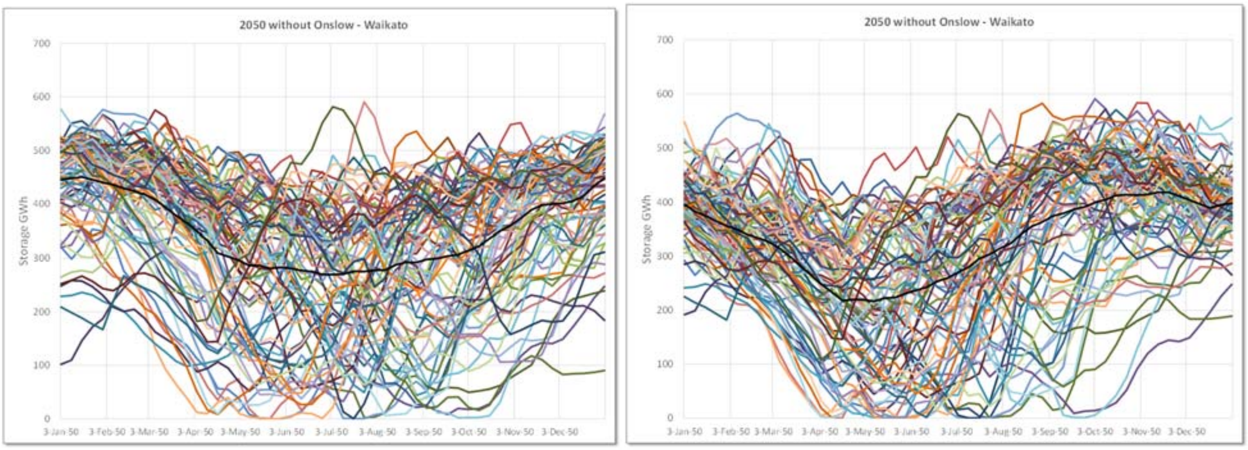
Figure 26: Waitaki storage in 2050



Waikato storage, however, hits empty in many inflow years, despite having a low buffer, with associated penalty, from August through to December.[26]

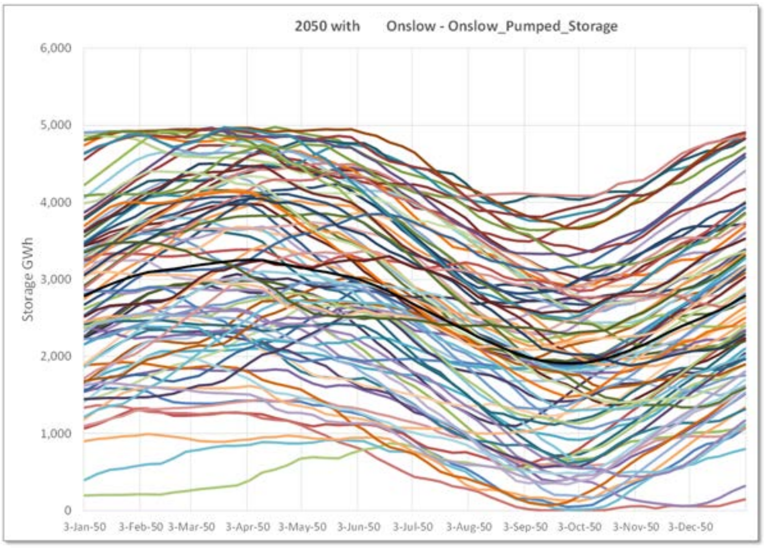
[26] See Appendix B for a full discussion on water values and reference to the role of a buffer in that context.

Figure 27: Waikato storage in 2050



As shown below, full use is made of the storage in Onslow in 2050.

Figure 28: Onslow storage in 2050



The results suggest that Onslow performs its role in preserving SoS, but it cannot contribute fully to security in the North Island due to the limited capacity of the HVDC link.

Furthermore, the storage charts for Waikato, along with the residual SLR and DSR, suggest that there is simply not enough capacity available in the North Island priced below DSR and SLR, either via the HVDC link or located in the North Island. Even in 2030, although Waikato storage behaves well, DSR and SLR are dispatched.

There are two aspects to this issue:

1. The price distribution in 2050, which may not provide a strong enough signal to build more new plant.
2. The role of the HVDC link.

Price distribution

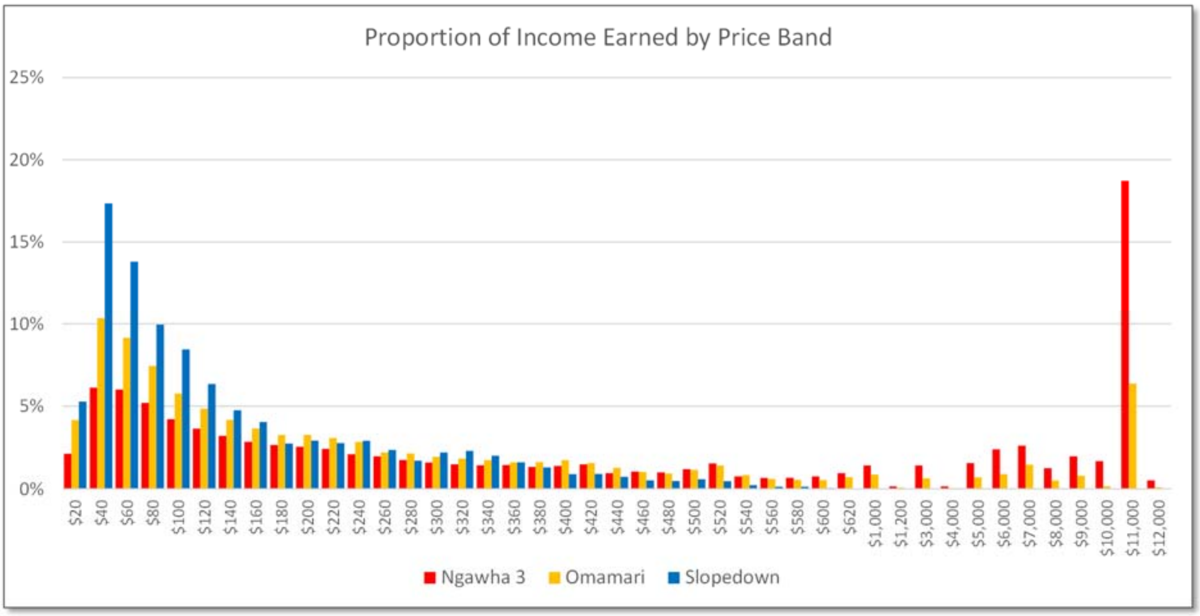
In 2050 with Onslow, despite capacity factors sitting at satisfactory levels, the market premium on new plant has fallen dramatically:

- for new windfarms, from an average of -18.4 per cent in 2030, to -33.8 per cent in 2050
- for new solar farms, from an average of -16.1 per cent in 2030, to -38.2 per cent in 2050.

The fall in market premiums is the result of the large increase in intermittent renewable generation, so as demand grows, the gap between demand and supply increase in those periods where intermittent generation is not generating, especially during cold, calm, and dark winter evenings. It is during these periods that the highest prices are set.

To illustrate this, Figure 29 shows the percentage of revenue earned in 2050 by the Ngawha 3 geothermal expansion and the Omamari windfarm, both located in Northland, by price bands at their injection nodes (KOE and MTO) in Northland, respectively. These are also contrasted with the Slopedown windfarm which connects at Gore.

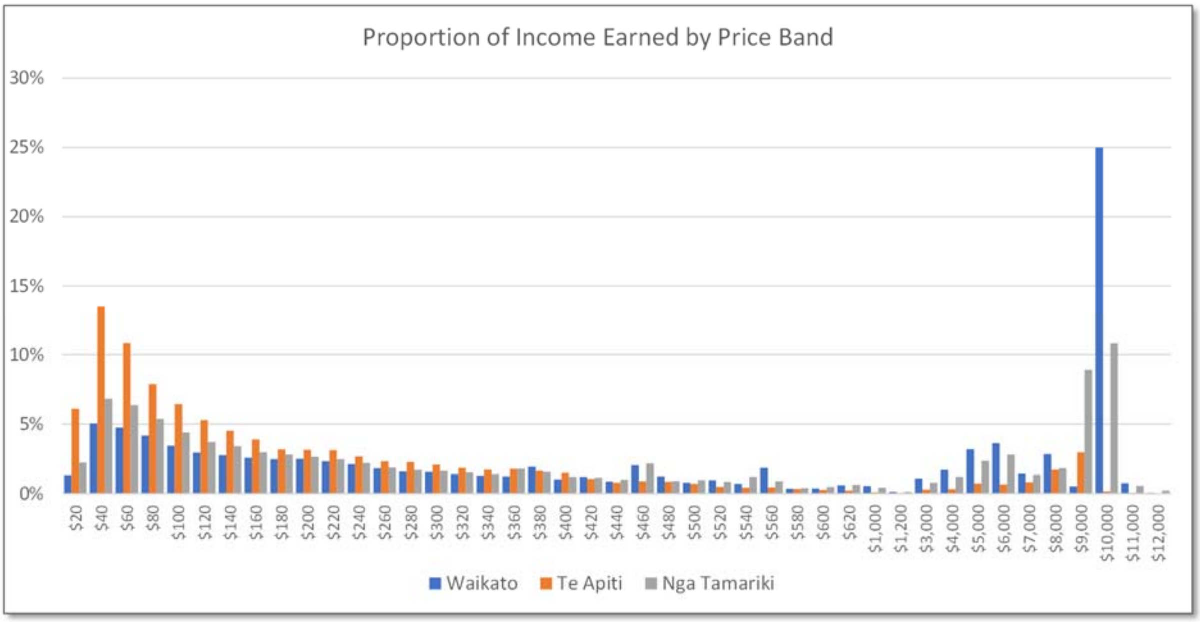
Figure 29: Revenue profiles of wind relative to geothermal in 2050



Omamari earns a much greater proportion of its income at prices below $500/MWh, whereas Ngawha 3 earns a higher proportion at the higher end of the price scale, with 19 per cent earned in the very high price band over $10,000, compared to Omamari's 6 per cent in this band. As a result, Ngawha's market premium remains at 0 per cent whereas Omamari's is -36.5 per cent in 2050.

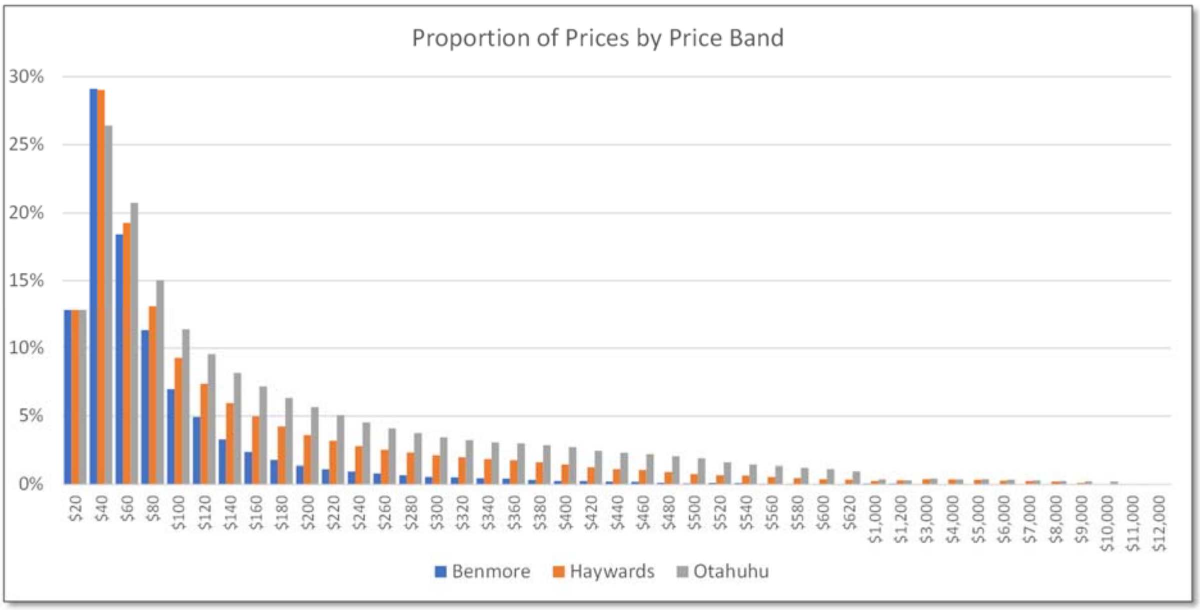
Plant that already exists today faces similar price distributions as shown below. The Te Apiti windfarm is currently in operation, but in the 2050 modelling it earns 89 per cent of its revenue at prices below $500/MWh, compared to the Waikato hydro system (52 per cent) and the existing Nga Tamariki geothermal power station (62 per cent). The Waikato system, in particular, benefits from its ability to operate flexibly and to respond to peak demand.

Figure 30: Revenue Profiles for Waikato, Te Apiti and Nga Tamariki in 2050



The two charts above show revenue by price band, but Figure 31 shows the frequency of modelled prices at Benmore, Haywards and Otahuhu in each of the same price bands. There only a tiny percentage of periods in which prices are set directly by DRS and SLR, starting in or close to $2,000/MWh, but these prices are so high that they contribute out of proportion to the frequency at which they occur.

Figure 31: Price Profiles in 2050



The pricing signals are such that firm plant is favoured if it can be built cheaply enough. However, even if it can, the fact that so much of a plant's revenue is earned during a small number of periods when prices are extremely high means that quite small changes in total capacity available during these extreme periods will cause relatively large changes in the RoI of new plant. Because of this, arriving at a stable, balanced build schedule is problematic in 2050.

Onslow helps meet the demand in these extreme situations in a predictable way, and hence helps to stabilise the market, but the capacity of the HVDC link restricts the amount of energy that can be transferred to the North Island.

The situation is different in the South Island, where Onslow is located. There is no new plant built in the South Island in 2030, but in 2050 there are three windfarms built and they have an average market premium of -10.9 per cent at the same time as North Island windfarms average -38.0 per cent.

This is further illustrated in the chart by comparison with Slopedown windfarm (shown in Figure 29), which connects at Gore and which has a market premium of -10.7 per cent.

Table 3 also shows the market premiums for the six generators, three existing and three new, that resulted from the modelled market in 2050, with Onslow in the South Is and limited additional storage in the North Is.

Table 3 – Modelled Market Premiums in 2050

Generator	Ngawha 3 Geothermal	Omamari Windfarm	Slopedown Windfarm	Waikato	Te Apiti Windfarm	Nga Tamariki Geothermal
Market Premium (GWAP/TWAP-1)	0%	-37%	-11%	34%	-40%	2%

The sensitivity of North Island prices to capacity is shown in the following table, which compares the balanced 2050 scenario with the same scenario with just 50 MW of geothermal capacity added. 50 MW is just 0.9 per cent of the total new MW capacity built by 2050, but it causes reductions of at least 20 per cent in average prices and at least 58 per cent in North Island DSR and SLR. This small amount of firm generation reduces the frequency and magnitude of DSR and SLR dispatch, which occur when prices are between $2,000/MWh and $10,000/MWh: these prices make a very substantial contribution to time-weighted average prices and to GWAPs.

Table 4: Addition of 50 MW of geothermal in 2050

Scenario	BEN Price	HAY Price	OTA Price	North Is DSR	North Is SLR	South Is DSR	South Is SLR
2050 with Onslow and Balanced Generation	$83	$116	$131	9.3	6.6	1.0	0.0
2050 with Onslow and an Additional 50 MW of geothermal	$64	$92	$105	3.9	2.4	0.5	0.0
Percentage Change	-23%	-21%	-20%	-58%	-64%	-51%	-

The $10,000/MWh offer price of SLR is used because it is in the electricity Code at the lower level of the scarcity pricing rules, which would set prices to between $10,000/MWh and $20,000/MWh[27] during periods of a shortage of generation offers relative to demand. These rules have never been activated since they were first introduced in 2012, but they could be in future, with 100 per cent renewable generation, under combinations of conditions that could occur based on forecast demand and the historical inflow data set: if investment in new plant is inadequate, demand is high, hydro

[27] The rules are slightly more complex than this, but this range is more than adequate for this discussion.

lakes are low in the North Island, and the HVDC link reaches its limit, or is otherwise impaired and operating below its full capacity.

Electricity markets may suffer from what is known as the ‘missing money’ problem, which means that GWAPs achieved by plant do not fully reflect the value of investment in these resources. Missing money was originally associated with regulated price caps, which prevented prices from rising high enough during periods of shortage to produce GWAPs that allowed new plant to achieve target RoI. But in 2050, the modelling shows that intermittent generation in the North Island could suffer from its own ‘missing money’ problem, even without regulation, and even as TWAPs rise.

This is a Catch-22 situation, in which the underlying issue is that intermittency causes periods of high prices, but the intermittent plant cannot fully benefit from these periods in terms of GWAP, because its generation has fallen (which was the cause of the high prices).

In the South Island, the combined impact of southern hydro and Onslow is not constrained by the grid, so periods of low intermittent generation do not require dispatch of DSR and SLR.

If more intermittent capacity is added in the North Island, then GWAPs fall and new plant does not achieve target RoI. If the HVDC link is upgraded, then North Island GWAPs will improve, but the North Island becomes more exposed to the risk of losing the link, as discussed in the next section.

Considering the missing money problem, and putting aside for the moment the possibility of upgrading the link, what is needed in the North Island is either considerably more storage, or a source of carbon-zero or carbon-neutral generation that is as firm and as flexible as the current fossil-fuelled thermal fleet. This would flatten the price distribution by reducing DSR and SLR, reducing the imbalance between geothermal and intermittent plant in respect of market premiums, and also reduce the average price overall. This would also reduce the returns to new plant, but this would be the more so to geothermal stations, which over-recover their costs compared to intermittent generation: but it is possible that it might further reduce the amount of new plant that actually has to be built.

Diversity and the HVDC link

Given that Onslow is located in the South Island, the HVDC link has a key role to play, and at first glance it would appear to make sense to upgrade the link to allow the maximum amount of energy to be transported northward to meet peak demand in the North Island.

As appealing as this may be, by increasing reliance on the HVDC link, electricity supply could become more exposed to a failure of the link even if that is a low probability event. This suggests that a very significant market impact of Onslow is its location, and the risk that this poses to supply in the North Island if the HVDC link were to have a prolonged outage.

To illustrate this point, we reran the 2030 scenario with one pole of the HVDC link out of service for the first three months of the year, as happened in 2020 when the Churton Park to Haywards section of the link had to be reconductored due to corrosion: the market was without one pole for almost three months, and during this time its capacity was limited to 400–450 MW. During this period, there were no interruptions to supply.

Figure 32: HVDC link outage Q1 2030

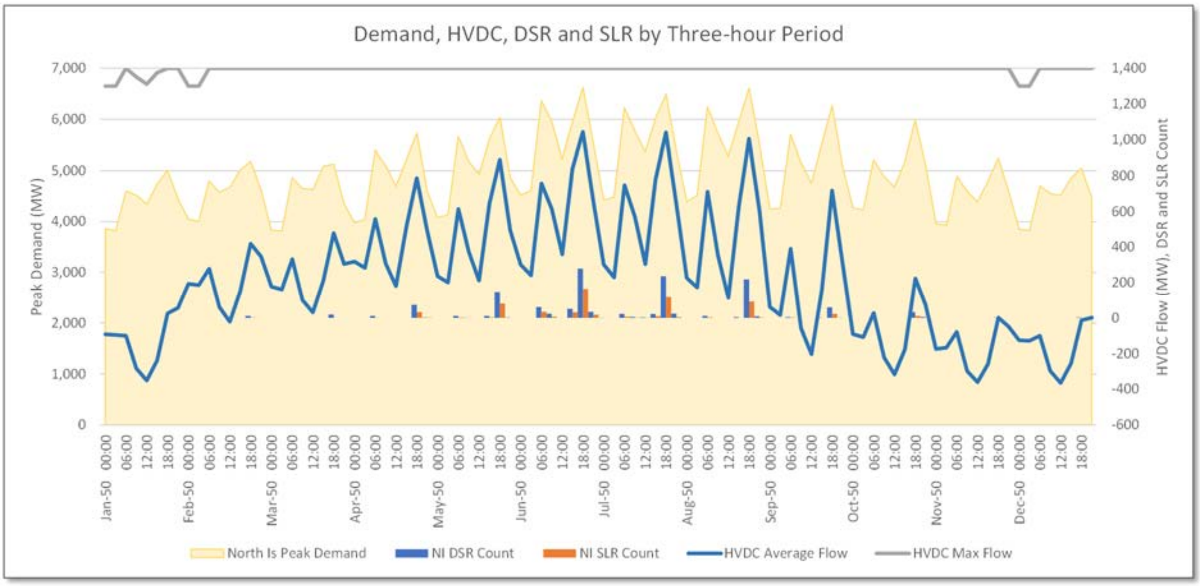
Scenario	North Is DSR	North Is SLR	South Is DSR	South Is SLR	BEN Price	HAY Price	OTA Price
2030 with Onslow and HVDC Fully Operational	2.7	1.2	0.0	0.0	$66	$79	$93
2030 with Onslow and HVDC One Pole for First Quarter	4.4	1.5	0.0	0.0	$63	$90	$105

We have shown earlier that in a 100 per cent renewable market and with the inclusion of Onslow, the dispatch of North Island DSR and SLR increases by 61 per cent and 18 per cent respectively, some of which could be non-supply. By locating all energy storage in the South Island, reliance on the HVDC link increases dramatically.

Figure 33 below shows data across all inflows and three-hour periods from the 2050 modelling with Onslow. HVDC flows peak in winter during the three-hour period starting at 18:00 (6 pm – 9 pm), which coincides with peak demand in the North Island. HVDC flows in summer average southward for long periods, following the same pattern as in the 2030 modelling, but even during this period the maximum flows consistently approach or reach the HVDC link's northward limit of 1,400 MW measured at Benmore.

The right-hand axis also provides a count of the number of times in each three-hour period that DSR or SLR are dispatched in the North Island.

Figure 33: North Island peak demand, DSR, SLR and HVDC flows



The chart above puts the increases in DSR and SLR required to balance the market discussed above into context: these increases occur in summer when HVDC flows are either southward on average, or only moderately northward. If an extended HVDC outage were to occur during the winter, when the frequency of dispatch of DSR and SLR is already at their highest levels, then the chart shows that DSR and SLR could increase far more than they did during the modelled HVDC outage in 2030. For example, in the 6 pm – 9 pm period in July, the HVDC link averages 1,041 MW northward: if the HVDC link were to fail during this period, then North Island DSR would be fully dispatched, and North Island SLR could be several hundred MW or more.

At the core of the issue is the loss of diversity that Onslow would create, despite its large contribution to preserving SoS and security. In the current market, there is a relatively high degree of geographical diversity, along with diversity in fuel supply for the fossil-fuelled thermal fleet, which can be fuelled either all on gas or a mix of coal and gas.

To assess this issue, we have applied the following security criteria. For this project, the application of the criteria is somewhat subjective so additional modelling may be warranted. The criteria applied is:

- North Island Winter Capacity Margin (NI WCM) – the planning standard for North Island capacity to ensure security of supply[28]
- The operating security standard (n-1) – where the power system is run to allow for the tripping out of the largest plant (generation or transmission – known as a Contingent Event (CE)) without activating automatic load shedding.[29] The operating standard also protects

[28] The North Island WCM and the Winter Energy Margin are collectively known as the security of supply standards. The System Operator must publish reports on the likelihood that the security of supply standard will be met over the next five years. The WCM is calculated to allow sufficient margin for secure North Island supply given a reasonable scenario of plant losses at what is economic to manage for. It is currently set at 630 – 780MW.

[29] Automatic load shedding is the last line of defence to prevent an island wide black out.

against an Extended Contingent Event (ECE) which ensures that if two linked plants trip out that each island stays live even though automatic load shedding may be activated.

- The transmission planning standard (n-g-1) – where the transmission grid is built to achieve the operating standard even where the largest generating plant may be out of service for an extended period. We consider the HVDC a generating plant in the receiving island for this assessment.

We do not consider the Winter Energy Margin, the margin that ensures enough spare energy is available to supply New Zealand during a dry period, as every scenario was specifically designed to meet the WEM.

In Table 5 these criteria are assessed on the following scale:

- Zero – zero impact
- Low – impact is under the level required for Code compliance (i.e. 30MW)
- Medium – impact is significant (i.e. greater than 30MW) but less than the current plant that most influences the criteria (generally a Manapouri unit (120MW) in the South Island and Huntly unit 5 (400MW) in the North Island)
- High – equal to the current plant that most influences the criteria as above
- Very high – significantly higher than the current plant influences so that the NI WCM will need to be redefined.

Table 5: Diversity and reliance on key assets

	Reliance on Key Assets for Security										
Scenario	SI hydro	NI hydro	Wind	Solar	Coal	Gas	Other	Storage excl Hydro	HVDC Link	AC Grids	Diversity Score
Present day	High	Low	Medium	Zero	Medium	High	Low	Zero	Medium	High	High
95% renewables	High	Low	Medium	Medium	Zero	Medium	Medium	Zero	Medium	High	High
100% renewables - ICCC 100%	High	Low	High	High	Zero	Zero	Medium	High	Very High	Very High	Low
100% renewables with Onslow	High	Low	High	High	Zero	Zero	Medium	Very High	Very High	Very High	Low

As shown in Figure 34, HVDC north flows have not exceeded 985MW over the last five years. With either pole capable of 700MW[30] when operating by itself (single pole mode), then the extended loss of a pole reduces North Island supply by no more than 285MW, less than Huntly unit 5 (the largest unit in the North Island, with maximum output of just over 400 MW depending on ambient conditions). Even though Pole 3 of the HVDC would be transferring 565MW when both poles are peaking at 985MW, because Pole 2 can instantly pick up Pole 3's load when it trips and overload for a short period, it is a lower CE risk than Huntly unit 5. The risk of both poles tripping at the same time is managed as an ECE risk; however, this generally hasn't required more reserves than Huntly unit 5 at the levels it has been operating at. Therefore, the risk for the HVDC currently is assessed as greater than 30MW and less than 400MW, and is medium.

Figure 34: HVDC flows April 2016 to March 2021

Source: Electricity Authority

In the scenarios without thermal, and especially with Onslow, the northward flows on the HVDC are much higher than shown above. Our analysis assumed that the HVDC capacity would be upgraded to 1,400MW for the future scenarios. At 1,400MW, then 700MW of steady-state capacity would be removed for an extended outage of either pole. This is significantly higher than the capacity of Huntly unit 5. The extra reserve requirements for the CE risk are roughly similar to the current situation, but this assumes that – with two cables – pole 2 can be overloaded to 1,000MW, which would need to be checked with Transpower. With the full HVDC capacity of 1,400MW often utilised with the large fossil thermal machines removed,[31] the ECE risk may require significantly more reserve. Taken together, the NI WCM is likely to need redefinition, and there are also implications for planning and the Security Policy, hence we rank the HVDC as Very High risk for security reliance on the 100 per cent Renewable and Onslow scenarios.

In many ways our assessment of the AC grids is similar to Onslow. The AC network is just as critical as the HVDC in transferring power across the islands. It is likely under the higher transfers north and south that more substations and outdoor switchyards will feature as ECE risks, where extended outages could limit transfers across the HVDC by significantly more than Huntly unit 5. This is a more

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[30] Normally Pole 2 of the HVDC has a maximum capacity of 420MW when operating by itself (single pole mode), but this is due to having only one undersea cable connected. For an extended outage of Pole 3 a cable can be swapped from Pole 3 to Pole 2. With pole 2 at 420MW the other pole has a capacity of 780MW

[31] Large thermal machines are a significant source of inertia. Inertia adds 'weight' to the power system and stops it being 'pushed around' for large events on the system. Less inertia will make the power system less stable and more difficult to manage.

subjective judgement than even that for the HVDC. However, these assessments also need to be considered in the context that significant 'Supply of Last Resort' is already required in the North Island in the 100 per cent Renewable and Onslow scenarios.

Other storage, modelled as batteries in our scenarios, could also be critical. This isn't just because of the higher requirements for WCM but also, as the AC grids are transporting more power further distances, both frequency and voltage stability could be issues. Storage located near demand is likely to play a critical role in helping stabilise the AC grids, meaning that the consequences of losing such storage could be a multiple of its capacity.

In the Present Day and 95 per cent Renewable scenarios there are a number of supply technologies that are ranked low or medium in terms of security reliance compared to those ranked high. There is a diverse range of plant that has some capacity to cover the high risk technologies, hence they are ranked high for risk diversity. In the 100 per cent Renewable and Onslow scenarios there are fewer supply technologies that are ranked less than high, and some that rank very high, hence these scenarios are assessed as having low risk diversity.

There is no doubt that the final retirement of the current fossil-fuelled thermal fleet will create the need for either a new form of carbon-free or carbon-neutral fossil-fuelled thermal generation or, more likely, large amounts of energy storage. The fossil-fuelled thermal plant being decommissioned is in the North Island, so its removal raises the dependency on the HVDC for supplying the North Island and with it the risk of blackouts if the HVDC fails. While Onslow could play a role in dry year risk, relying on just one large energy store located in the South Island would constitute a major loss of diversity, and locks in the risk of blackouts if the HVDC were to fail.

While some HVDC outages are foreseeable and perhaps able to be mitigated or managed, the "unknown unknowns" are of major concern.

Building redundancy into the HVDC link certainly is an option, but it is also expensive.

In framing the business case for Onslow or any energy store, maintaining diversity and managing the risks of unplanned outages must be one of the key considerations taken into account. Building pumped storage and other energy storage in the North Island would be highly desirable in terms of managing this risk.

Furthermore, the build schedules assume that the current market structure remains. The fossil-fuelled thermal fleet currently adds to security in the form of actual generation, but also in the form of 'standby reserves': this is plant that is offered but not dispatched, either for energy or reserves. If an outage occurs, reserves act to bring the frequency back into the frequency-keeping control zone, within the 15-minute offload time specified by Transpower. But after 15 minutes, it may be standby reserve capacity that is dispatched to replace the outaged plant.

Currently, the capacity factors attained by gas-fired peaking plant are generally low enough that there is almost always standby reserve capacity available. But there is nothing in the current market structure which, with 100 per cent renewable generation, would ensure there are always enough standby reserves available. The focus of this report and the modelling is on Onslow, and a large-scale North Island battery was not considered. Ignoring the issue of who would build it, as we have done for Onslow, however, it is clear that a large-scale NZ Battery solution located in the North Island could play a key role in ensuring security and in contributing to SoS, or a combination of Onslow and a smaller North Island solution.[32]

Onslow's net revenue

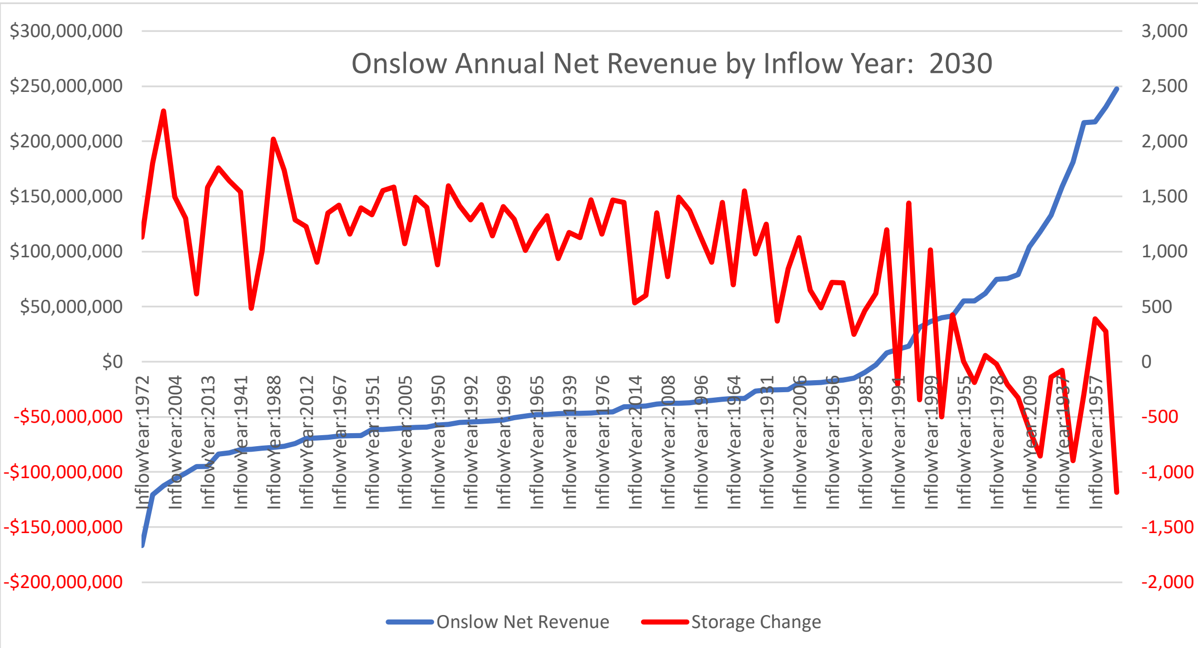
Onslow uses its water values to offer into the market as generation and also to bid its pumping demand into the market as dispatchable demand. The demand bid price is lower than the offer price due to the pumping efficiency, which means that during any particular week there is a price dead-band within which Onslow neither pumps nor generates, and so it is entirely possible that when prices are close to Onslow's water value, it will pump and generate within the same day (we illustrate this in our example at Figure 13).

However, there are long periods of low prices when it only pumps and long periods of high prices when it only generates.

Onslow's net revenue is the sum of its annual generation revenue less the sum of its annual pumping revenue. Figure 35 shows the distribution of annual net revenue in 2030, along with the change in Onslow's storage over the year. In 2030, the start and ending storage values are not quite converged, and storage ends up higher on average at the end of the year, which means that Onslow's average net revenue is -$17 million, and the correlation between storage change and net revenue is clear: when storage ends up lower at the end of the year, this is typically due to a dry period, in which prices are high.

If we look only at years in which storage ends at about the same as it started, then the annual net revenue is between $55 million and $90 million.

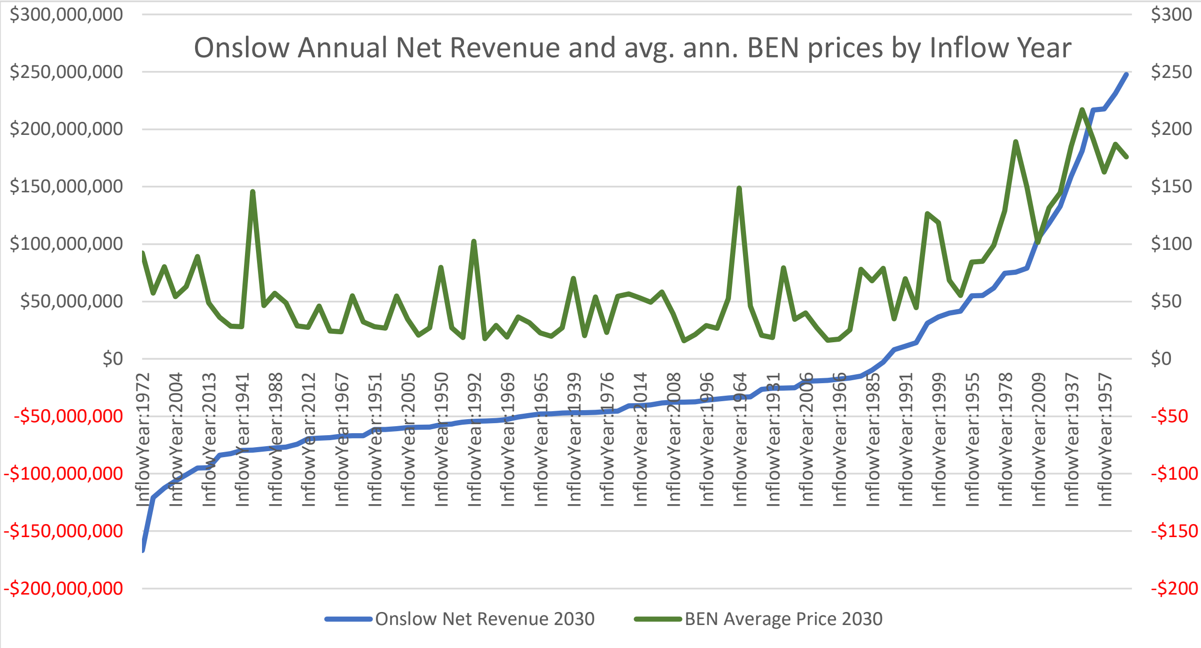
Figure 35: Onslow net revenue distribution and storage change 2030



[32] Smaller in terms of energy storage. The capacity may need to be similar.

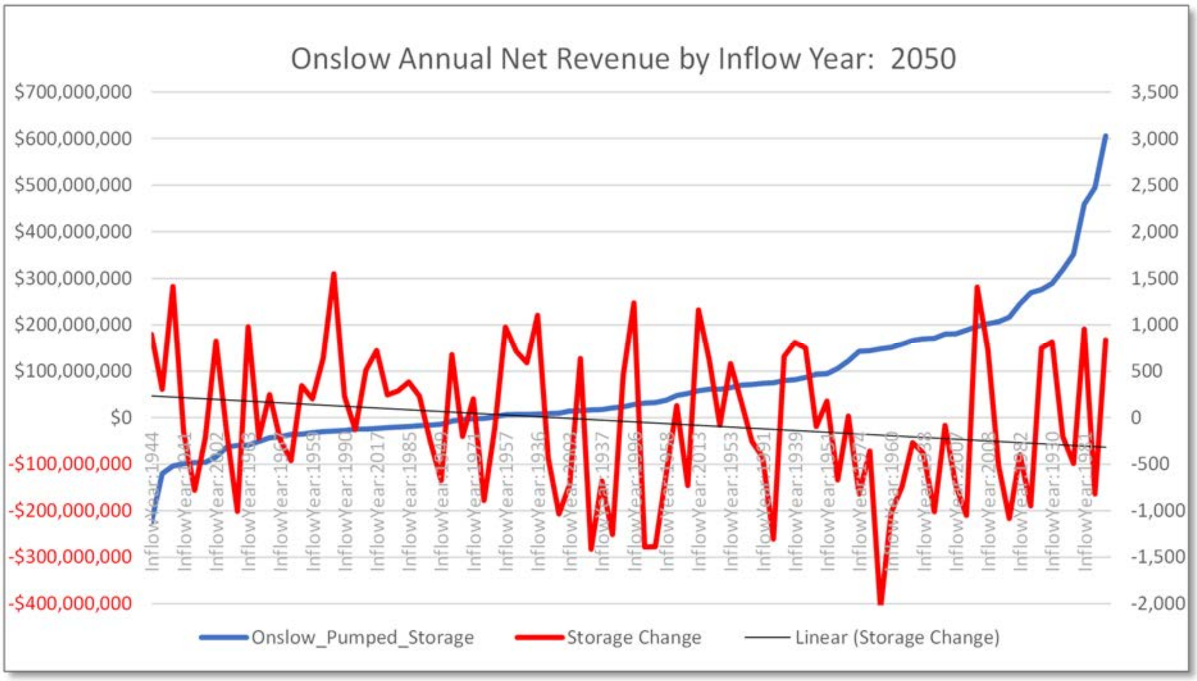
The impact of dry periods is also illustrated in the 2030 chart below in which the net revenue distribution is plotted along with the average price at Benmore for the corresponding year. During a dry period, water that was added to storage when prices were lower is sold at a substantial premium to give positive net revenue.

Figure 36: Onslow net revenue distribution and Benmore price 2030



In 2050 the correlation with storage change is not as marked because in this scenario the average start and end storage are about the same, and average net revenue is $66 million.

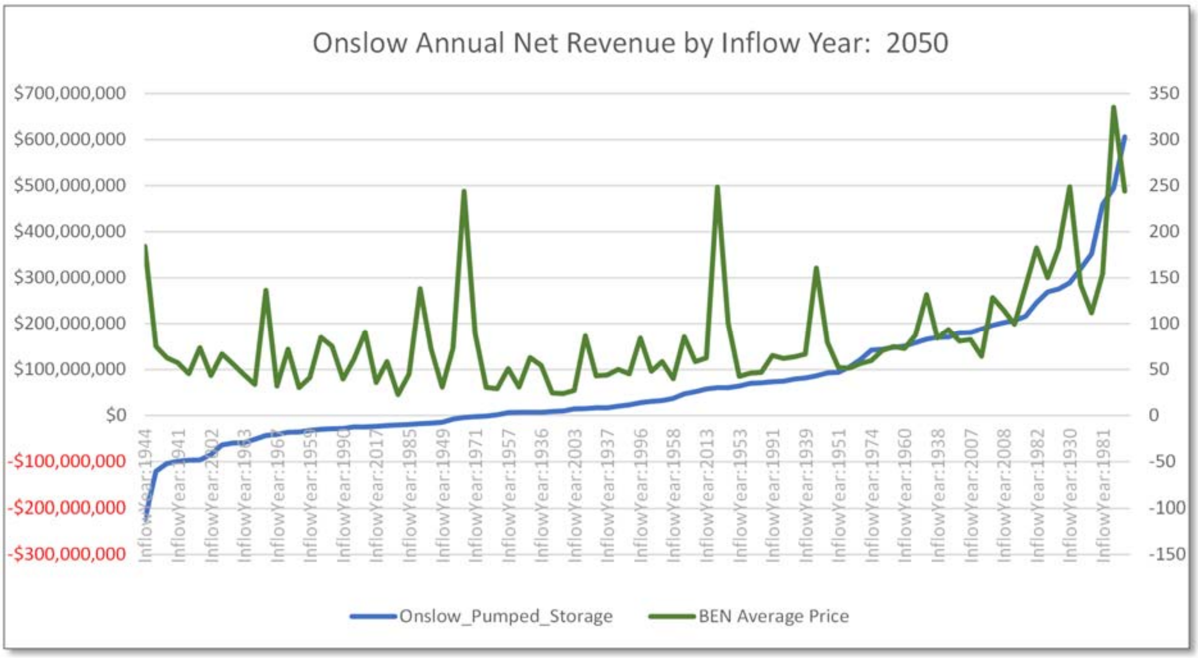
Figure 37: Onslow net revenue distribution and storage change 2050



 Confidential

But the correlation between net revenue and price is still clearly seen in Figure 38.

Figure 38: Onslow net revenue distribution and Benmore price 2050



Transmission

EMarket has a model of the grid made up of 221 nodes and 296 lines and key transformers. There are more lines in the grid than this, but many are in parallel with other lines, so in *EMarket* parallel lines are aggregated into one line, thus reducing the number of lines and the size of the power flow that must be solved at each dispatch.[33]

Line limits can be enforced, but when future years are run in *EMarket* it is typically run with most limits not enforced, to avoid slowing down the run. In the Onslow modelling, only the HVDC limits were enforced, along with the equation constraint between the Clutha and Waitaki Valleys.

The following two tables show the lines that ran over their respective limits in 2030 and 2050, and the percentage of three-hour periods in which they ran over, taken across all inflow years. The tables do not include lines that got near to their limits.[34]

[33] Outages of one of the parallel lines can still be modelled.

[34] This data can be extracted.

Table 6: Lines running over their limits in 2030

Line	BPE1_MTR1	MTR1_OKN1	TWC2_TWT2	RPO2_TNG2	OKN1_RTR1	TKU2_WKM2	AVI2_WTK2
Periods of positive overload	2.918%	0.449%	0.307%	0.092%	0.047%	0.002%	0.001%
Periods of negative overload	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%

Table 7: Lines running over their limits in 2050

Line	BPE1_MTR1	MTR1_OKN1	TWC2_TWT2	RPO2_TNG2	OKN1_RTR1	ATI2_WKM2	CML2_TWZ2	ONG1_RTO1	ONG1_RTR1	AVI2_WTK2	BPE1_WDV1	TKU2_WKM2	KOE1_MPE1	OTA1_WIR1	RPO2_WRK2	BPE2_TKU2
Periods of positive overload	11.653%	3.809%	3.145%	2.400%	1.143%	0.858%	0.351%	0.072%	0.062%	0.047%	0.020%	0.016%	0.014%	0.010%	0.009%	0.008%
Periods of negative overload	0.000%	0.001%	0.000%	0.117%	0.014%	0.000%	0.005%	0.146%	0.365%	0.000%	22.115%	0.032%	0.000%	0.000%	0.003%	0.287%

EMarket can also model equation constraints such as "SFT" constraints[35] but does not calculate these on the fly. SFT constraints are often the constraints that constrain dispatch in the current market, and when they start to appear frequently, may be the first indicator of the need for a grid upgrade. Energy Link does have another model which can calculate SFT constraints, but this is a time-consuming job for the whole grid, so this task was not undertaken.

Despite the limitations of this approach, it nevertheless indicates which lines or regions in the grid will need to be reinforced in future.

Grid nodes BPE1_MTR1[36], MTR1_OKN1, OKN1_RTR1, ONG1_RTO1 are on the 110 kV grid running northward from BPE and are obvious candidates for upgrades with the higher power flows caused by the combination of Tiwai closing and Onslow, as the line they are on is in parallel with the North Island core 220 kV grid.

BPE1_WDV1 is on the 110 kV line running through to Fernhill on the East Coast near Napier, and is likely to need upgrading simply due to the amount of wind energy connected in the region.

TKU2_WKM2 is in the core 220 grid running west of Taupō, and has caused constraint issues in the past. RPO2_TNG2 is also in the core 220 kV grid south of Taupō and has also caused constraint issues in the past, as has BPE2_TKU2, also on the core 220 kV grid.

CML2_TWZ2 is one of the lines which makes up the equation constraint between the Clutha and Waitaki valleys, and its presence in the table is an indicator that the CUWLP[37] project currently underway may not provide enough capacity to avoid constraining the output of Onslow in future.

AVI2_WTK2 appears in both tables, but it will be protected by a new run-back scheme as part of the upgrade work required in anticipation of Tiwai closing.

[35] Simultaneous Feasibility Constraints. These protect one line from overloading post the loss of another line.
[36] The number suffix indicates voltage, 1 for 110 kV and 2 for 220 kV.
[37] Clutha Upper Waitaki Lines Project.

Taken overall, the lines tables above show that grid upgrades beyond the HVDC link will be required with Onslow in place, although a number of these would be required in anticipation of Tiwai closing or for other reasons.

However, the HVDC link is a major point of constraint, even once it is upgraded to 1,400 MW north and 950 MW south, by adding a second Cook Strait cable to Pole 2. The two charts below show daily averages, across all inflow scenarios, for HVDC transfers, along with daily minimums and maximums.

HVDC flows hit their southward peak on average during summer when Onslow charges, then hits their northward peak in winter when Onslow generates, on average. There is substantial demand on Onslow for peaking, especially in the North Island as demand grows, so that by 2050 it hits 1,400 MW north on almost all days (across all inflows): the pricing impact of this constraint was noted above.

Figure 39: Daily HVDC flows in 2030

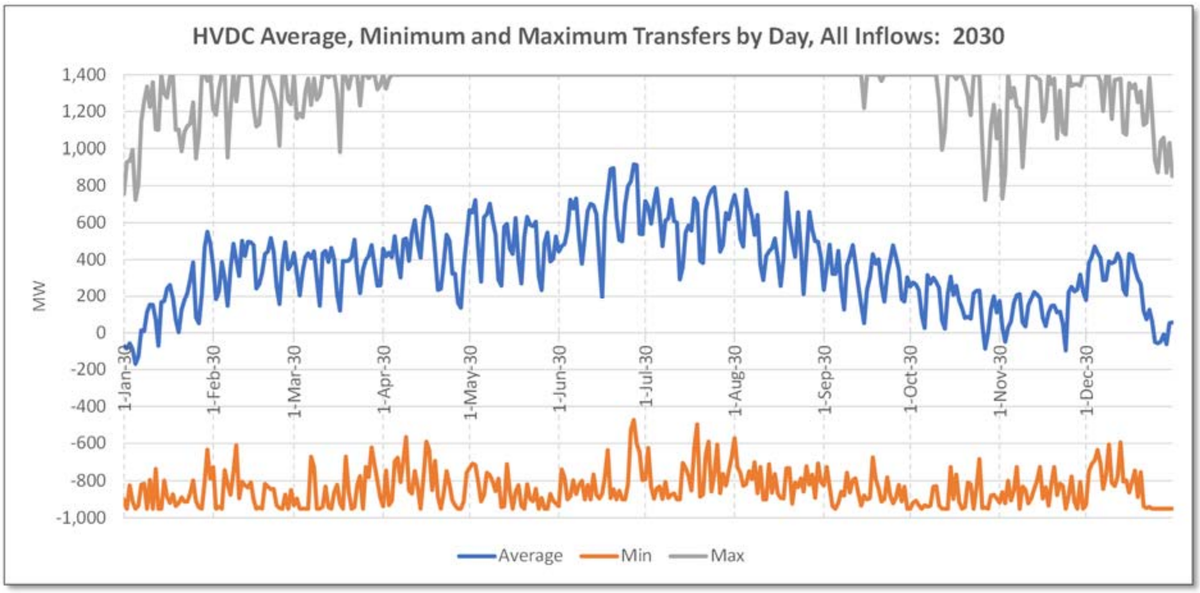
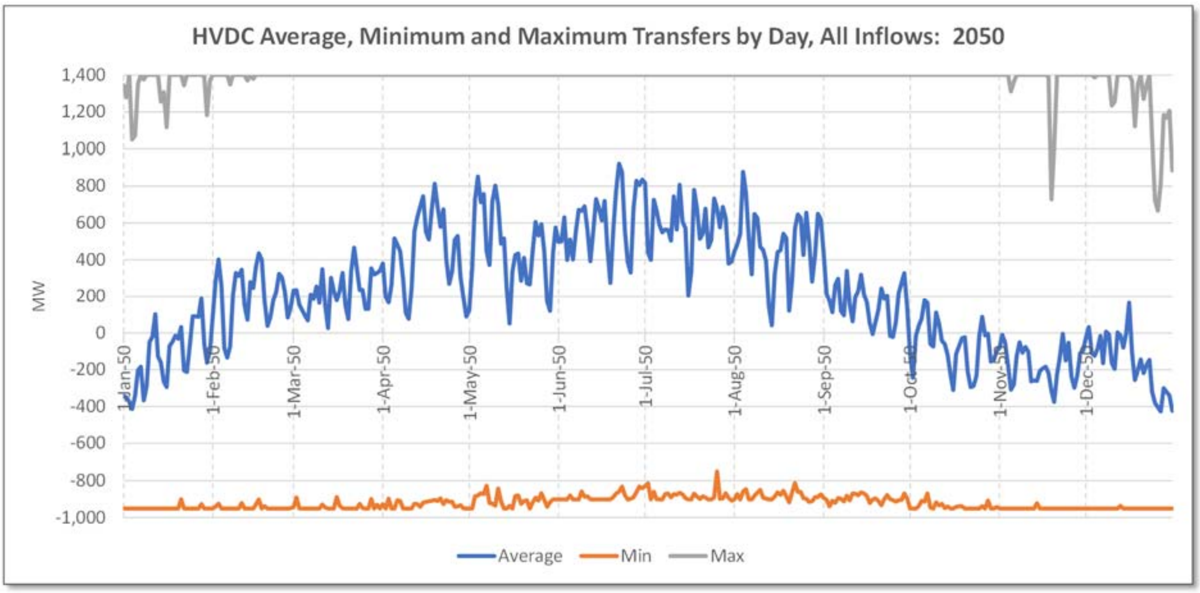


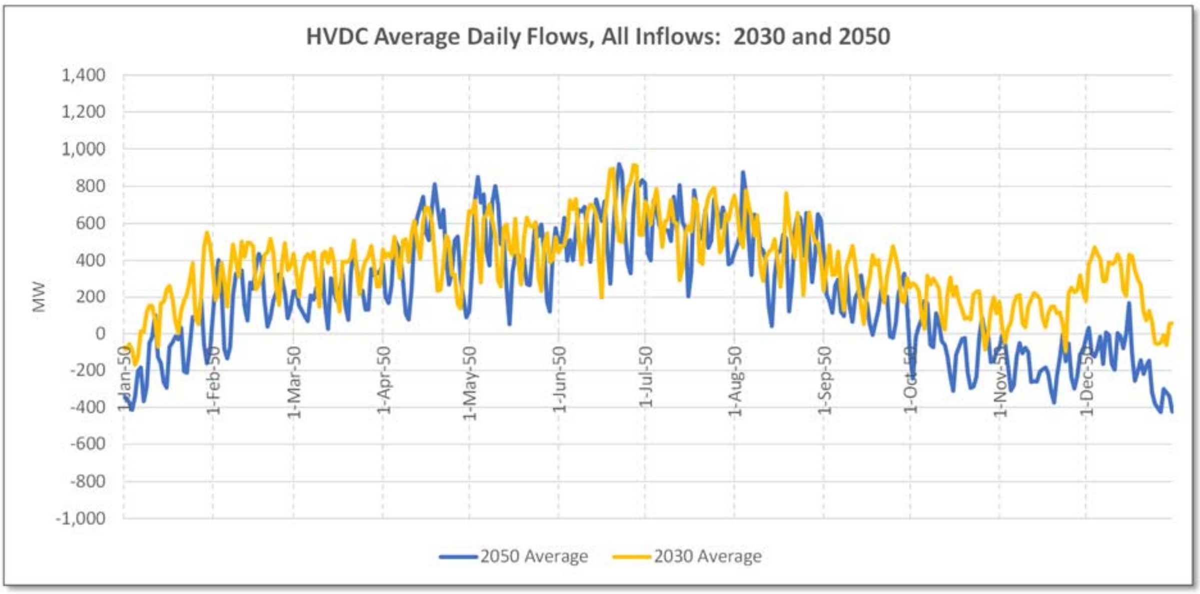
Figure 40: Daily HVDC flows in 2050



As well as strong seasonal pattern, the HVDC link also shows the weekly pattern reflecting lower average and peak demand during weekends.

Comparing the average flows in both years, shown below, 2050 has higher southward flows during the ‘charging season’ because Onslow is ‘working harder’ in 2050, with a greater range of storage covered.

Figure 41: Daily average HVDC flows 2030 and 2050



Modelling key takeaways

- Adding Onslow to the market after supply becomes 100 per cent renewable achieves the objective of reducing the additional generation capacity required to achieve SoS.
- Onslow also contributes substantially to preserving security but is limited in the contribution it can make to North Island security by the capacity of the HVDC link.
- The combined effect of removing fossil-fuelled thermal generation in the North Island and building Onslow in the South Island reduces the overall diversity of the electricity supply system and increases its reliance on the HVDC link compared with the present.
- With or without Onslow, 100 per cent renewables in 2030 presents a substantial challenge to get enough plant built to preserve security: market premiums for intermittent generation, wind and solar, fall relative to plant that can operate at or near baseload.
- Onslow has to be filled to its normal operating range, within a reasonable time. That can either be achieved by allowing fossil-fuelled thermal generation to remain in the market for a year or two after Onslow is commissioned, or bringing forward renewable generation needed to cover ongoing load growth through the electrification expected to deliver the decarbonisation objectives.
- Operating Onslow with a bid and offer strategy based on water values would achieve positive net revenue on average, but there would be a large range from very negative to very positive, depending on prices and hydrology in each year.
- Adding Onslow reduces prices and price volatility to a modest extent compared to the situation with 100 per cent renewables in the early years. However, by 2050 in the North Island, price pressure and volatility is evident where meeting peak demand presents significant challenges.
- In 2030 and 2050, the HVDC link constraints lead to persistent price separation between North Island and South Island prices. In particular there would be extremely high prices when DSR and SLR is dispatched, which depresses, in turn, the realised prices for wind and solar farms in the North Island relative to geothermal stations; these imbalances indicate the value of significant amounts of storage in the North Island and/or of significant transmission investment.
- The current market structure may not deliver sufficient spare capacity to ensure there is always enough standby reserve capacity available and to refill Onslow after a dry year.[38] We expect this will be the subject of further study following the completion of this work.

[38] The fossil-fuelled thermal fleet currently adds to security in the form of actual generation, but also in the form of 'standby reserves': this is plant that is offered but not dispatched, either for energy or reserves. If an outage occurs, reserves act to bring the frequency back into the frequency-keeping control zone, within the 15-minute offload time specified by Transpower. But after 15 minutes, it may be standby reserve capacity that is dispatched to replace the outaged plant.

Implication for the next phase as MBIE develops the scope for the business case for NZ Battery

We have:

- considered the policy context in which the NZ Battery study is being conducted
- developed a default operational model and pricing approach for an Onslow project for the purpose of testing how an NZ Battery solution would interact with the market
- analysed the likely security of supply and security settings in the current market with fossil-fuelled thermal removed in line with the 100 per cent renewable electricity in 2030 policy. We have shown that either the market has to overbuild a great deal to provide security of supply or Government can intervene so the market requires less overbuild, it can continue to fill all of its roles and security of supply is assured.
- projected the security of supply and security settings in 2050 with Onslow in the market and the market design otherwise unchanged
- taken into account advice from MBIE and the team working on problem 1 on the method of intervention to meet government objectives
- demonstrated the market impacts of the intervention based on the Onslow scheme, notably the loss of diversity in the system and the risk of non-supply in the North Island under certain conditions.

This work provides the NZ Battery project a framework for thinking about the operation of a state-owned intervention in the market and sets out a full range of matters we recommend should be taken into account. The implication for the next phase of the project is that all of these matters should be resolved when the business case for a project is developed.

Appendix A. Assumptions

We have a made a number of assumptions in order to provide a first cut of how Onslow would interact with the market and what market outcomes would look like. The exercise is made more challenging by the fact that we had to make some assumptions to model, the starting point being the market without fossil-fuelled thermal generation performing the roles we are familiar with today and contributing to price formation as it does today. Individually, some of these assumptions could be debated at length, and for future modelling there may well be some changes.

Assumptions common to 2030 and 2050

The modelling was undertaken assuming inflation is zero, so all costs, prices and revenues are expressed in real terms.

At the outset we determined:

- Onslow would be operated on the basis of pricing referenced to water values.
- the potential for the market participants or Onslow itself to exercise market power to may exist but we have assumed that this does not occur
- we have not tested outcomes for the impact of inter-year variability in wind or solar generation
- we have not fully captured the impact of more than two consecutive dry years.

The common key assumptions are listed below.

1. The wholesale electricity market remains in place more-or-less as it is today, in line with the requirements of the Code.

2. The ETS operates as it does today. We include a discussion about the carbon price below.

3. Fossil-fuelled thermal generation plant is forced to retire by 2030.

4. The Tiwai Point aluminium smelter is no longer operating by 2030 and is not replaced by a similarly large load.

5. The HVDC link has capacity of 1,400 MW north at Benmore and 950 MW south at Haywards, with overload capacity[39] of 1,000 MW (see further comments below).

6. Historical inflows are representative of future inflows: we know that new records for low inflows are still being set, and there is evidence that inflows may be changing due to climate change, but there is sufficient variation in inflows in the historical data set for our purpose of assessing the impact of Onslow on the market.

7. Generators will target an after-tax real RoI of 4.4 per cent, which is the WACC that arises from a target post-tax real target RoI of 5.88 per cent (8.0 per cent nominal assuming 2 per cent

[39] This is the total HVDC transfer, arriving at Haywards, that can be achieved without needing reserves to cover HVDC risk.

inflation) along with 50 per cent leverage with interest set at 4 per cent per annum.[40]

$0.5 \times 5.88\% + 0.5 \times 4.00\% \times (1 - 0.28) = 4.38\%$ where 0.28 is the corporate tax rate of 28%.

8. $12/MWh is a reasonable value for the SRMC of new wind farms (see further discussion below).

9. Hydroelectric generators spill water when their respective reservoirs are full, but offer generation while spilling at a price which is greater than zero but less than the offer price of wind farms.

10. Contingent storage can be used in extreme dry years.

11. Storage in general is managed in a way which makes Official Conservation Campaigns (OCCs) very unlikely events.

12. The TPM is modified in a way which removes the current HVDC charge component and removes the bias currently in favour of building new generation in the North Island.

The offer price for wind generation

To be clear, the $12/MWh offer price of windfarms creates a hierarchy for spill in which wind is 'spilled' before water and solar, the latter offered at $0.01/MWh. It may or may not be the case that windfarms offer at this price in future, because their maintenance contracts may have both fixed and variable pricing elements. Currently, the risk of being dispatched off[41] is low for windfarms, so there is typically no need to offer at SRMC and hence to bear the costs associated with frequent dispatch instructions. But in future, there will be long periods when prices are close to or below windfarm SRMCs, and their owners may well consider it worth the cost and effort required to be dispatched off when prices reach or fall below $12.

In terms of the modelling, the primary benefit of pricing windfarms at $12 is that windfarms become the prime indicator of over-build; this leads to longer periods when windfarms are dispatched down, and hence to a fall in their average capacity factor and GWAP.

The carbon price

A modest carbon price of $46 per tonne CO_2 was assumed, although it plays no role in the detailed modelling. Geothermal generation is the only renewable generation modelled that has any emissions, and if the carbon price were to get to very high values, this could change the order in which new plant is built, potentially favouring wind and solar before geothermal. However, it was important to include some geothermal plant amongst the new plant built in 2030 and 2050, to contrast to the other renewable technologies and, especially in 2050, new geothermal plant gains a much better financial return than wind and solar, so would still be built even with much higher carbon prices.

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[40] Energy Link's usual practice is to calculate LCOEs using the full financing structure, but for the purpose of this modelling exercise, a single WACC is used instead.

[41] Instructed by the system operator to generate less than indicated by generation offers

DSR

Four DSR suppliers are modelled, with two located in each island. The DSR offers are the same of each location with five offer bands of $2,000, $4,000, $5,000, $6,000 and $8,000/MWh. The offer band size is 20 MW in 2030 and 30 MW in 2050. By 2030, and certainly by 2050, DSR could take many forms including, but not limited to, contracted load-reduction in response to price, and voltage-to-grid power transfer from EVs and batteries installed in residential dwellings and businesses.

Standalone privately owned batteries

The 2030 modelling has five batteries modelled varying in size. There is a single South Island battery which has 1,200 MWh storage with a 150 MW generation rate. The North Island has four batteries, with a total of 3690 MWh storage and 540 MW combined generation.

The 2050 modelling has six batteries varying in size. There is a single South Island battery which has 2,400 MWh storage with a 150MW generation rate. The North Island has five batteries, with a total of 11,090 MWh storage and 1,040 MW combined generation.

The batteries are generic in the sense that they do not assume any particular technology, so they could be lithium-ion, sodium-ion, flow batteries, and potentially other technologies that will be cost-effective in the future. However, these batteries are assumed to be installed primarily for the purpose of managing grid security, either at the transmission level, or at the distribution level. Each battery can contribute to meeting peak demand, but they could also simultaneously provide other services such instantaneous reserves and voltage support.

SLR

In order to derive meaningful outputs we have arrived at four SLR suppliers, with two located in each island. The SLR offer is the same for each location at $10,000/MWh. The offer band size is 500 MW in 2030 and 1,000 MW in 2050.

Onslow

In runs that include Onslow, it is configured with 5,000 GWh of storage capability, 1,000 MW of generating and pumping capacity, pumping efficiency of 75 per cent, generator characteristic of 5.41 MW/cumec,[42] injecting at ROX2201. It is also assumed that Onslow can change from pumping to generating within the three-hour time step used in the modelling.

It is assumed that the tunnel connects Onslow to a point below the Roxburgh dam, which minimises the tunnel length and hence, all else equal, construction costs. There are other pros and cons to connecting below the dam, or above the Roxburgh dam: below the dam does not take water from Roxburgh generation, but then it does not add water for generation at Lake Roxburgh. Connection

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[42] *Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand's South Island*, PhD thesis, M K Majeed, 2019.

below Roxburgh also offers an independent Onslow operator the least interaction with Contact Energy.[43]

There are no penalty prices applied when Onslow storage approaches full or empty levels.

The HVDC

The HVDC link's 1,000 MW overload capacity, along with net free reserves for FIR, means that quite small amounts of instantaneous reserves would be required to cover HVDC risk. This could be provided by PLSR, TWD, ILR and also from batteries that are included in the plant mix.

The transition to 100 per cent renewables

An assumption which is implicit in all modelling runs is that Onslow reaches a stable operating state at the end of 2029. Although beyond the scope of this report, it does raise the question of how this will this occur.

Onslow is a large reservoir with a tunnel connecting it to the Clutha River. Under the assumptions of 5.41 MW/cumec and 75 per cent pumping efficiency, the maximum charge rate is only 139 cumecs, which would be required for 9.1 months to fill the lake. This assumes that it would be filled entirely before entering its normal operating mode, which is unlikely if, for example, there is a dry period while filling.

The results of the modelling show that Onslow reduces the amount of renewable generation that needs to be built to replace fossil-fuelled thermal generation. But to fill Onslow, surplus energy is required, which could come either from fossil-fuelled generation or from surplus energy available from renewable generation.

In the former case, Energy Link undertook modelling in 2020 which suggests that filling using fossil-fuelled thermal generation would take around two years and create emissions of approximately 570,000 tonnes of CO_2, when averaged over all 89 years of historical inflow data. Some years when inflows are high, will require little or no thermal generation because there will be surplus energy available from hydro generators. But if Onslow happens to start filling at the start of a prolonged dry period, then filling would create significantly more than 570,000 tonnes.

In the latter case, unless the building of renewable capacity was brought forward at least two years, perhaps using some additional but temporary market mechanism, then filling could take significantly longer than two years, and would occur when inflows are high, the wind is blowing, and the sun is shining.

The conclusion from this brief discussion, is that the transition from having fossil-fuelled thermal generation in the market to having none, needs to be worked through carefully.

Other assumptions for 2030

The 2030 run is based on the ICCC's 100 per cent Base Case.

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[43] There is a minimum flow requirement below Roxburgh, but when this is likely to be binding, Onslow is more likely to be generating.

- Demand: Tiwai gone, 0.5 per cent p.a. growth, plus 100 MW South Island data centre, plus 600 GWh of process heat conversion to electricity;
- Medium-term demand elasticity as per ICCC – response to high prices and OCCs;
- Contingent storage total of 668 GWh.

Other Assumptions for 2050

- Demand for 2050 is matched to the 2050 demand value used by Concept Consulting for Problem 1, i.e. 56 TWh per annum;
- Contingent storage total of 668 GWh;
- Medium-term demand elasticity as per ICCC – response to high prices and OCCs;
- 4 x 150 MW hydrogen powered batteries, one located in the South Island and three in the North Island. Each offers 5 offer bands at 20MW, 40 MW, 35MW, 35 MW and 20 MW. The offer prices are $400, $500, $600, $700 and $800/MWh.

Appendix B. Water values 101

The term ‘water value’ is used extensively in this report, and this section provides a basic introduction to the concept. A full description of water values is quite mathematical and beyond the scope of this report.

To assist with the explanation, we will step through:

- water values in a market with fossil-fuelled thermal (i.e. the current market)
- water values in a 100 per cent renewables market (i.e. the position in 2030)
- water values as a way of maximising security of supply (in both kinds of markets)
- water values and security.

Water values in a market with fossil-fuelled thermal

The modelling assumes that the current market structure remains intact through to 2050 notwithstanding the absence of fossil-fuelled thermal, which means that generators over 10 MW have to offer into the market in order to be dispatched.

The modelling also assumes that the operator pricing the water for dispatch will adopt the now conventional approach to valuing releases from stored hydro used in some form or another by hydro operators in New Zealand. The derivation of the implicit value of water at a given generation offer in $/MWh is explained numerically in the box below.

> Suppose that the operator of a hydro generator with storage offers to generate up to 100 MW at a price of $100/MWh, and that its generators convert water to energy at the rate of 2 MW per cumec. This means that the energy content of water stored in the hydro lake is 2/3,600 MWh per m^3 (0.00056 MWh/m^3) or 2/3.6 kWh per m^3 (0.56 kWh/m^3).
> If the generator is dispatched at 100 MW and it is marginal,[44] then revenue will be earned at the rate of $10,000 per hour on water releases of 50 cumecs or 180,000 m^3 in total: this gives the value of the water released as $0.056/$m^3$.
> This places a value of $0.056/$m^3$ on the water released during the period. But not all of the water in the lake is released, so it is in fact the marginal value of water in storage.

What this tells us is that no matter how one might choose to value water in storage, the price attained at the time of release determines the actual value of the water released. This applies to all existing lakes and would apply to Onslow.

This is all very well, but if you have a large hydro lake to manage, then you would want to be more systematic in determining the dollar value that you place on each m^3 in storage, and hence on the price at which you offer the next marginal release into the market.

[44] Which means that the generator’s offer is marginal and hence sets the price.

The concept typically used in the electricity context is that of the water value, which is short for marginal water value for the reason noted above. The techniques and algorithms used to calculate water values originated in electricity markets featuring a mix of hydro and fossil-fuelled thermal generation, in which it was highly desirable to value stored water in a way which maximised a specified objective for the management of hydroelectric storage lakes, e.g. minimising fuel burn.

The variable costs of fossil-fuelled thermal generators are primarily set by the cost of fuel and carbon and they are typically substantial, whereas the variable costs of hydro generation are close to zero or, if not, then relatively small. For example, the fuel cost of operating a fossil-fuelled thermal station such as a gas-fired peaker with heat rate of 10,000 GJ/GWh[45] and with gas priced at $10/GJ and a carbon price of $40 per tonne is $121/MWh. On the other hand, the variable cost of running a large hydro system is a few dollars per MWh at most, plus, if the generator is in the South Island, the HVDC charge of $5.35/MWh.[46]

If hydro generators offered to generate at less than $10/MWh while fossil-fuelled thermal generators offered at prices reflecting their variable costs, then prices would initially be low, but only until all the lakes emptied out, after which they would have to rely on run-of-river inflows to generate; at which point prices would be very high, reflecting a shortage situation and the cost of generating a lot of power from fossil-fuelled thermal generators.

Exactly the opposite would happen if hydro generators over-valued their water relative to fossil-fuelled thermal generators; prices would be high until all the lakes filled up and started spilling.

Neither of the above scenarios is desirable, and they illustrate why it is important to get water values right. It also points to the importance of how water values would apply if the market has no fossil-fuelled thermal.

The approach used is to calculate the optimum water value in each period, typically weekly, which establishes the opportunity cost of water in storage, where opportunity cost is the value of the next best alternative to generating today. Since the vast majority of stored water is used for electricity generation,[47] the only alternative to generating today is to generate tomorrow, or the day after tomorrow, or the day after the day after tomorrow, and so on.

Tipping[48] draws on the literature to expand on this:

> "On any given day, the hydro generator holds a portfolio of real options,[49] such as the option to generate today, the option not to generate today, and the options to generate or not on any day in the future. As storage is limited and inflows stochastic,[50] generating today can compromise the ability to generate in the future. Therefore, the marginal cost

[45] Based on HHV efficiency of 36%.
[46] This charge is due to be abolished when the new TPM comes into force in 2023.
[47] In large hydro lakes, a small portion might also be used for irrigation.
[48] *The Analysis of Spot Price Stochasticity on Deregulated Wholesale Electricity Markets*, PhD thesis, James Tipping, 2007.
[49] Investopedia defines a real option as "an economically valuable right to make or else abandon some choice that is available to the managers of a company, often concerning business projects or investment opportunities."
[50] Uncertain.

> of hydro generation includes not only the physical cost of passing water through the turbines, but also the value of options both created and destroyed by generating today."

A hydro generator typically has the objective of maximising profit when calculating water values, taking into account highly uncertain inflows, and subject to constraints including the size of the hydro lake, the maximum rate of release, and MW per cumec ratio of the generator, reducing the risks of shortage, and other variables.

A large profit-maximising hydro generator may also take advantage of its market power when calculating water values, but when market power is ignored then the use of water values should, in theory, achieve the same market outcome as would a central utility seeking to minimise the total cost of generation over a period. In a hydro-fossil-fuelled thermal electricity market, minimising the cost of generation comes down to minimising the cost of the total fuel burn: this also maximises the value of water over the period.

We can expect the operator of Onslow to develop its own optimisation algorithm to calculate water values that achieve its objective, subject to constraints: for example, the primary objective would be to achieve a specified level of SoS. Other objectives may also come to the fore if, for example, NZ Battery also had facilities targeted at security in the North Island.

For the modelling in this report, Energy Link used its *EMarket* model which simulates the operation of the electricity at a high level of detail, and a key part of this is to calculate water values for each major hydro reservoir.

EMarket's water values are produced from an optimisation with the objective of maximising the revenue from a hydro lake with uncertain inflows, over a specified period of at least one year in length, at weekly time steps, assuming that market power is not used. As a result, the water values maximise the value of water and hence also minimise the value of the fuel burned by fossil-fuelled thermal generators.

For a particular lake, the water value changes with the lake's own storage, with the storage in other lakes, with the (expected) offers from fossil-fuelled thermal generators, with demand, with expected renewable generation, and also taking into account the cost of DSR and the possibility that SLR will be dispatched (which could include non-supply). At any point in time, the water value for a storage lake provides its operator with a starting point for the price that it offers its generation into the market.

Water values are often calculated on grids of storage (for the lake in question), storage in all other lakes, and time. But this multidimensional grid view is not intuitive, and so *EMarket* converts its grids into water value contours, which were inspired by the operating guidelines produced by the SPECTRA model developed by ECNZ back in the 1980s.

Figure 42: Simplified water value contours

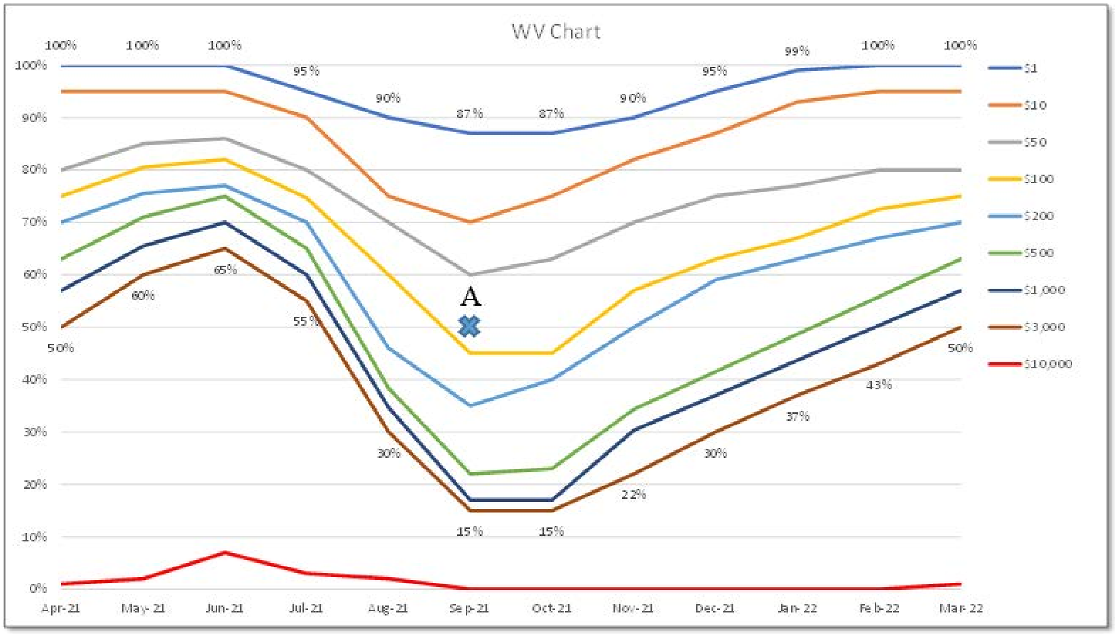


Figure 42 shows some simplified water value contours for a generic lake, with storage marked on the vertical axis in terms of percentage full. Each line is a water value contour at a constant price, which is a more convenient expression of value than using dollars per m^3.

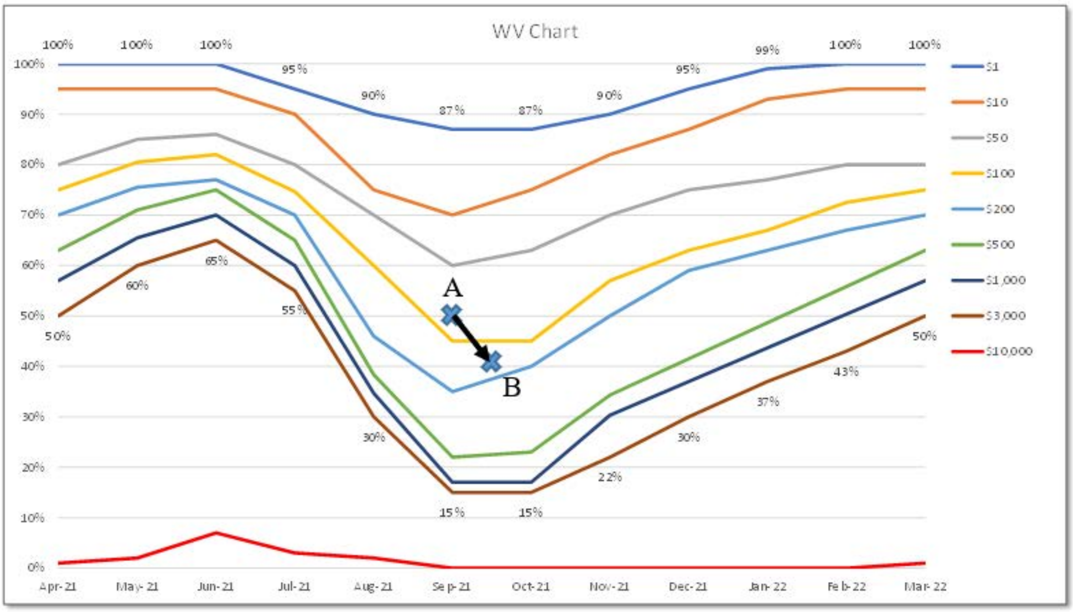
For example, at point A, which is at the 50 per cent storage level in September, the water value is part-way between the yellow ($100) and grey ($50) contours. Using simple linear interpolation between the two prices, the water value at A is about $83/MWh.

Water values are calculated using many possible inflow scenarios, usually based on historical data, which are projected into the future. As storage falls below A, for example, more projections fall into lower storage zones, and hence the WV increases.

Suppose there is a significant fossil-fuelled thermal sector, as there is today. Then the water values can be constructed so that each one is priced at one of the offers of a fossil-fuelled thermal generator. In theory then, as storage crosses one of these contours, the relevant fossil-fuelled thermal offer should be dispatched into the market. The contours with prices of $500 and above are more likely to represent demand-side response (DSR), supply of last resort (SLR) and, ultimately, non-supply at prices above $10,000.

For example, suppose storage falls from A to B, as shown in Figure 43, in the first half of September. If the yellow contour at $100 represents an offer from a fossil-fuelled thermal generator, then this offer should be dispatched into the market as the contour is crossed. In this way, as storage falls, more fossil-fuelled thermal generation comes on, and this acts to slow the rate at which storage falls (for if it falls too far, then shortages could occur).

Figure 43: Fossil-fuelled thermal dispatch



If the fossil-fuelled thermal sector is sufficiently large and competitive, then any market power possessed by a large hydro generator is highly constrained. If capacity is withheld or offer prices increased, then more fossil-fuelled thermal will run and storage will tend to increase again.

Currently, the fossil-fuelled thermal sector has three significant players – Contact Energy, Genesis Energy and Todd Generation – so there is no shortage of competition in this sector.

Of course, if gas prices generally rise, then the prices on the fossil-fuelled thermal-based WV contours will rise accordingly, and water values will also rise, which is why gas prices are a key driver of electricity spot prices, even though we have far more hydro generation than fossil-fuelled thermal generation.

Water values in a 100 per cent renewables market

When there is no fossil-fuelled thermal generation, it turns out that we can still produce sensible water values, but now the only contours that relate to the actual dispatch of non-hydro generation are at the very low end of the range and at the very high end of the range.

At the low end, we have offers starting at zero for must-run plant such as geothermal, then $0.01 for solar farms, run-of-river hydro and small price takers, and windfarms offered in at $12/MWh.

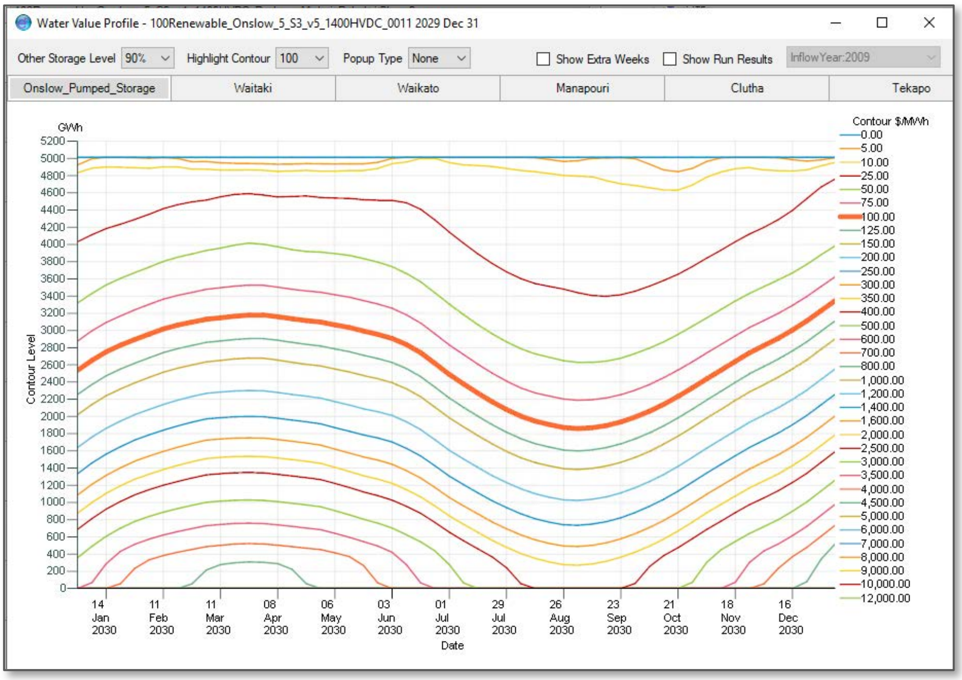
At the high end of the range, we have DSR and SLR which are modelled with offer prices between $2,000 and $10,000. Water value contours of hundreds of dollars are still present at lower values of storage because forward projections of inflows may stray into high priced zones, so these contours reflect the rising probability, as storage falls, of the future dispatch of DSR and SLR.

***EMarket's* water values**

The following charts show water value contours for the 2030 run with Onslow. Once water values are calculated for a run, they simply need to be looked up each week as the market simulation progresses.

Figure 44 shows the water value contours for Onslow when all other storage is 90 per cent full on an aggregate basis[51] and highlights the $100/MWh contour.

Figure 44: Onslow water values with other storage at 90% full



The contours rise to a plateau or peak from April to early June, and then fall to a minimum at the start of September. This is a familiar pattern for southern lakes, which contain most of the storage in New Zealand, and intuitively, this occurs because a prudent operator would want to have higher storage going into winter as inflows fall and demand rises. Then once in winter, inflows are expected to start rising from August onward, and demand to fall from August onward. In fact, what the water values do is to substantially improve on human intuition.

Figure 45 shows Onslow's water values when the total of all other storage is at 30 per cent of full, which pushes most contours up significantly. Effectively, the water values respond to the heightened risk of shortage when other storage is at 30 per cent, relative to the risk at higher storage values.

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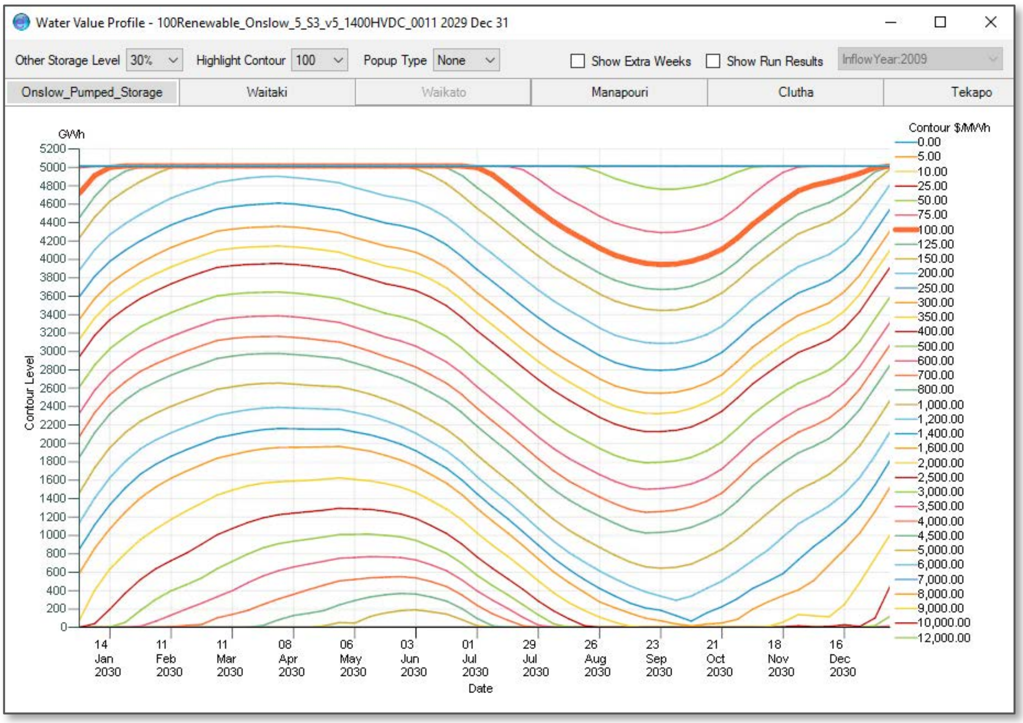
[51] Some lakes could be less than 90%, some greater.

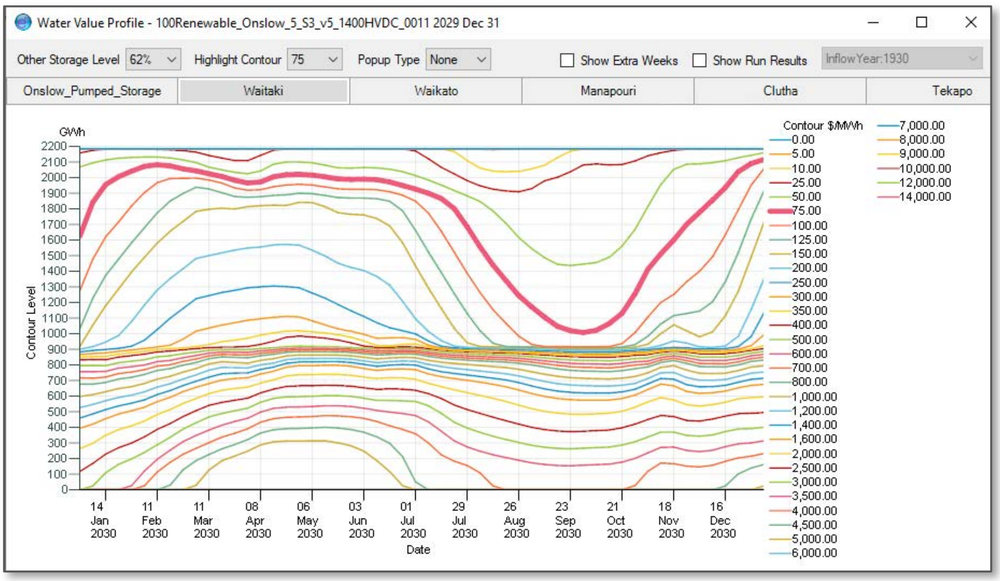
Figure 45: Onslow water values with other storage at 30% full



In any given week, *EMarket's* water values are linearly interpolated between the contours for each lake, and the state of other lakes, with the other lake storage specified for a range of storage values from 0 per cent to 100 per cent.

The water values shown above can be compared to those for Waitaki (Lake Pukaki) shown below, and they look quite different, for two reasons.

Figure 46: Waitaki water values with other storage at 62% full



First, Onslow is a much larger reservoir with virtually no natural inflows, so it is not subject to the same vagaries of inflows as the smaller lakes: it chooses when to charge and when to discharge.

Second, it does not have penalty prices associated with very low or very high storage, whereas Waitaki does have a small spill penalty applied and, more importantly, a significant low storage penalty which creates a 'buffer' zone below about 900 GWh of storage.

Waitaki's total storage includes contingent storage of about 500 GWh, but this is only able to be used in situations where storage is so low that it is essentially a national emergency, and an OCC has commenced. In addition, we observe that Meridian Energy is conservative in its operation of Lake Pukaki, and so the actual size of the low buffer reflects this. Arguably, the presence of Onslow may cause Meridian to be less risk-averse, but for the time being we have retained the low buffers and spill penalties that we observe in the market today.

The presence of buffers and penalties does not prevent storage being in the extreme high or low zones, so spill can still occur and, in extreme cases, storage can fall into the low buffer zone and even into the contingent zone.

Water values as a way of maximising security of supply

The use of low buffers is one lever that can be used to help keep storage from falling so low that OCCs or actual shortages occur, but there is a more important aspect of water value optimisation that achieves SoS.

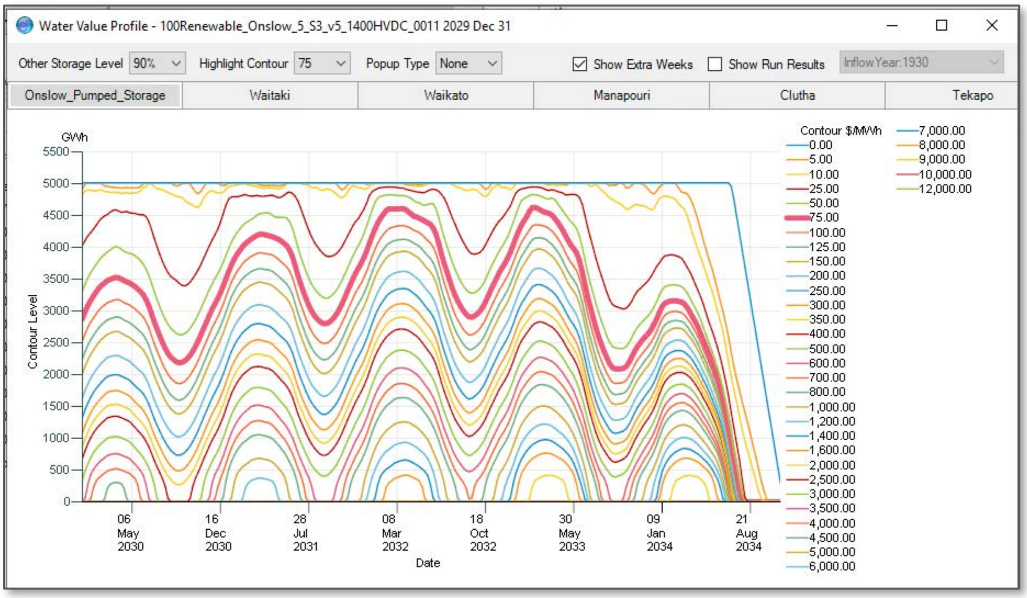
In the discussion of water values so far, only the current year is considered, 2030 or 2050 as the case may be, but if a hydro lake owner only had a horizon of one year, they would simply generate to ensure that storage hit zero near the end of the year, then 'walk away'.

But hydro lake owners aim to stay in business year after year, and they must consider the impact of this year's operation on subsequent years. This is achieved in *EMarket* by running the water value optimisation at least one year beyond the end of the forecast horizon and, with Onslow in the market, the optimisation is actually run for a few years beyond the end of the forecast horizon, due to the fact that it is such a large lake. Figure 47 shows the full range of Onslow's water values for the 2030 run, extending to the end of 2034. The fall in water values starting mid-2033 is indeed due to the optimisation seeing the 'end of' Onslow, and it literally responds by running storage to zero through 2034.

But for all years through to 2022, the water values ensure that each successive year achieves SoS.[52]

[52] In this particular case, demand increases after 2030, which results in the water values rising year-on-year.

Figure 47: Multi-year water values for Onslow

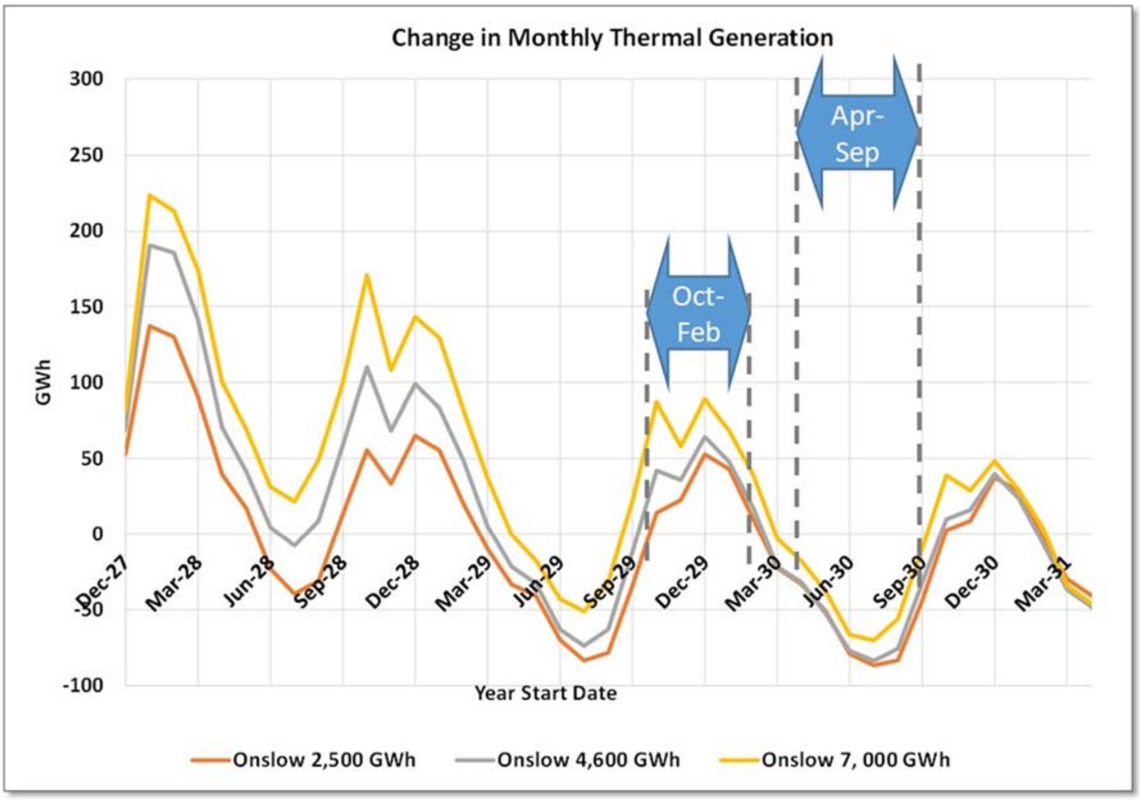


The following case study illustrates how Onslow's water values work to preserve SoS. Again, it is easier to first illustrate the operation of the market to first consider a market with fossil-fuelled thermal, and then consider a 100 per cent renewables market.

it is based on the market without enough renewable capacity to be 100 per cent renewable, so fossil-fuelled thermal remains, but it is informative because it is easier at first glance to understand the interactions between Onslow and the fossil-fuelled thermal fleet, and then to extend the understanding to the market with 100 per cent renewable generation.

The case study was run by Energy Link in October 2020, using a base case without Onslow, and the following charts compare the with-Onslow results to the without-Onslow results.

Figure 48: Change in fossil-fuelled thermal generation with Onslow added to the market



Relative to the market without Onslow, fossil-fuelled thermal generation averaged over 89 years of inflows, falls due to the reduction in spill from the hydro lakes. Figure 48 above shows the change in fossil-fuelled thermal generation for the three scenarios that were modelled: Onslow capacity 2,500 GWh, 4,600 GWh and 7,000 GWh, with 1,300 MW of capacity[53] in each case.

In this study, Onslow was commissioned in January 2028 and initially fossil-fuelled thermal generation is considerably higher than it was without Onslow; this is the initial charging phase.

But once Onslow enters its normal operating mode after a couple of years, fossil-fuelled thermal generation averages higher in summer and lower in winter than it would be without Onslow, while being lower overall. The economic reason for transfer of fossil-fuelled thermal generation from winter to summer is illustrated in Figure 49 below.

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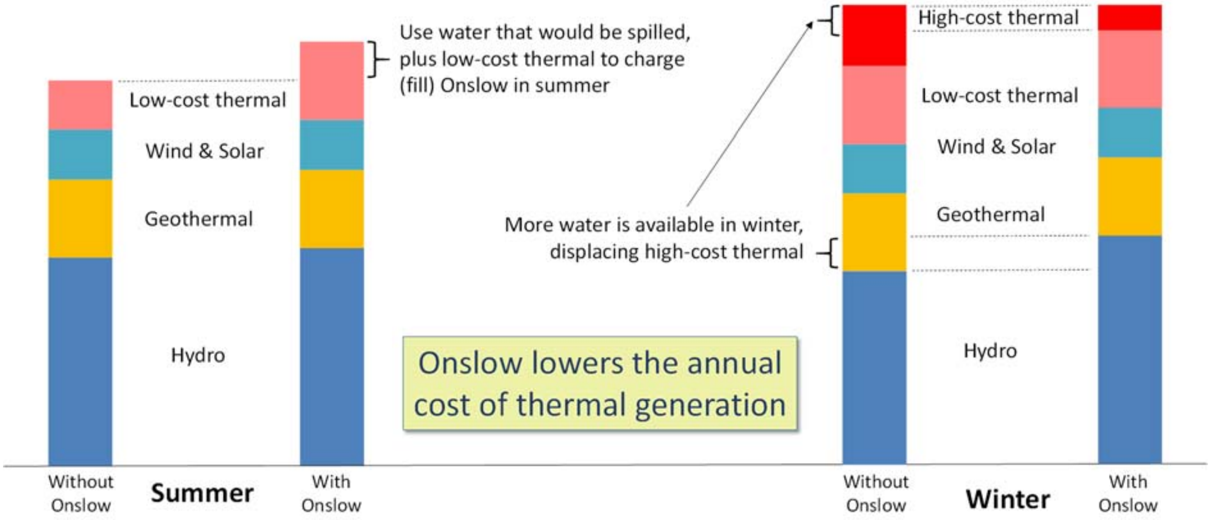
[53] See Majeed.

Figure 49: Onslow with fossil-fuelled thermal in the market



Looking first at summer generation (on the left) without Onslow, summer fossil-fuelled thermal generation may be required, but on average it is much less than what is required in winter (on the right) and hence cheaper than winter fossil-fuelled thermal generation. Without Onslow in winter, if the lakes are also low, then considerably more fossil-fuelled thermal generation is required; as progressively more is required, it is progressively more expensive, as shown in the Without Onslow column in winter.

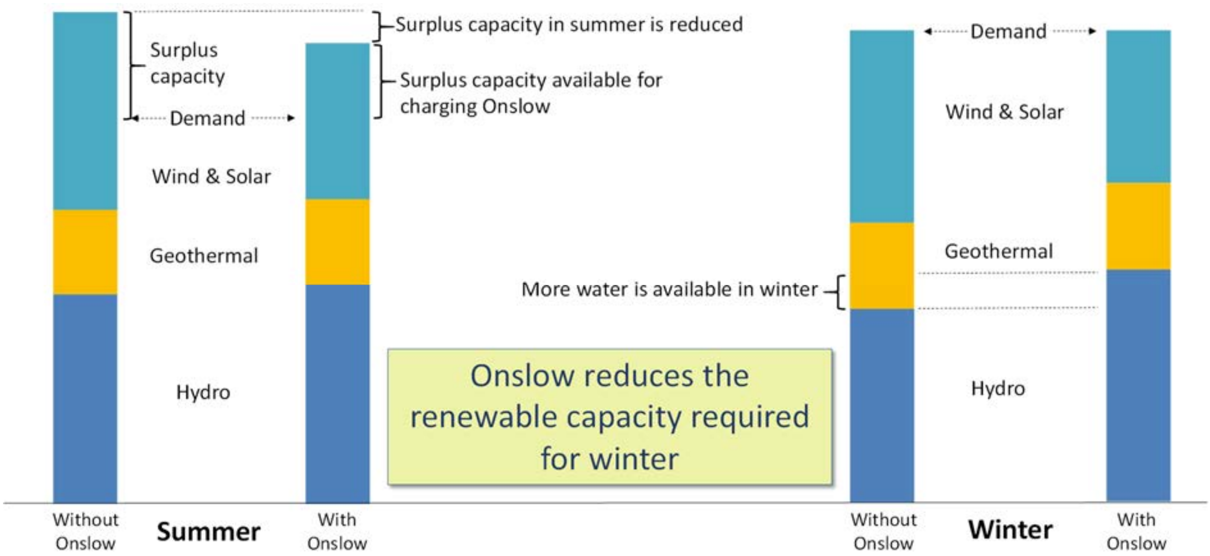
What Onslow does is to charge during summer, which uses more of the cheaper fossil-fuelled thermal generation, but then Onslow has water stored to generate with in winter, displacing the more expensive fossil-fuelled thermal generation.

So in essence, Onslow lowers the overall cost of preserving SoS by:

1. reducing the total amount of fossil-fuelled thermal generation required, on average; and
2. reducing the cost of the fossil-fuelled thermal generation that is still required, by charging in summer using spill and low-cost fossil-fuelled thermal, and generating in winter, thus reducing the amount of high-cost fossil-fuelled thermal generation required in winter.

It is not quite so obvious how Onslow works with 100 per cent renewable generation, but it is again illustrated in simple terms in Figure 50.

Figure 50: Onslow with 100% renewable generation



Without Onslow in the market, 100 per cent renewable electricity supply can, in principle, achieve SoS and security if there is an over-build of renewable plant, as shown in the Without Onslow column for summer: the over-build is not there for summer, it is there for winter, when demand peaks after dark, potentially on evenings when it is calm across the country and when the lakes may also be low.

With Onslow in the market, however, the over-build can be reduced, but even then there is spare capacity in summer, which is used to charge Onslow, leaving it with storage to generate through winter, filling the gap potentially left by not over-building.

It should be kept in mind that in winter, Onslow can use its water values to determine its generation based on the market price, and thus to help to achieve both SoS and security.

To complete the picture, however, we need to ask the question: what is the economic factor that drives this behaviour?

The answer is that meeting peak demand, or achieving SoS in winter, ultimately may require the dispatch of DSR and SLR, which although present in relatively small quantities, are nevertheless very expensive resources. By charging in summer and being ready and able to generate in winter, to help preserve SoS and security, but displacing DSR and SLR, the overall cost is reduced, just as it is when fossil-fuelled thermal remains in the market.

Water values and security

The discussion of Onslow tends to focus on how it can achieve SoS, but it is now clear that there is another element to water values which is highly relevant to the assessment of the impact of Onslow on the market.

The water values establish the expected future value of water – the opportunity cost – but water values are typically indifferent as to whether generation occurs solely to preserve SoS or to ensure security.[54] In fact, the operator of Onslow could reasonably take the view that any time the price received in the market exceeds the water value, Onslow should generate. This will obviously occur during dry periods but also during demand peaks when capacity is in short supply.

This makes perfect sense when one considers that fossil-fuelled thermal generation currently in the market plays two roles: one is to generate during dry periods, but the other is to fill the gap during peaks periods when hydro and any other peaking plant is fully dispatched. The fossil-fuelled thermal generation performs two key roles, one for SoS and one for security.

Considering that Onslow has both storage and capacity in good measure, there is no reason why it cannot replace, to the extent possible, the fossil-fuelled thermal fleet in both of these roles, particularly as the amount of energy required to assist in preserving security is far less than the energy required for SoS.

Water value key takeaways

- Water values are a particular case of 'energy-in-storage' values, but the generic concept of energy-in-storage values as an opportunity cost would apply to any battery with long-term (seasonal) storage.
- Water values as the basis for market offers are proven in New Zealand, and work for Onslow.
- Water values optimisation adjusts to the market, and would typically be undertaken weekly to capture on-going changes such as demand, plant outages and plant commissioning.
- Water value is the opportunity cost of generation and (after efficiency loss) charging.
- Water values will tend, on average, to charge Onslow in summer and discharge it winter, thus minimising the overall cost of preserving SoS and security.
- Onslow's operator would offer and bid to the market, while at least returning water value.
- Onslow's operator would develop its own water value optimisation program that would be based on the overriding objective of achieving a specified level of SoS, subject to a range of constraints.

[54] Onslow's operator could instead decide to determine water values based only on generating to preserve SoS and to ignore the need to preserve security. But this would require additional capacity to be retained in the market in order to preserve security, increasing the overall cost of electricity supply.

About Sapere

Sapere is one of the largest expert consulting firms in Australasia, and a leader in the provision of independent economic, forensic accounting and public policy services. We provide independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

'Sapere' comes from Latin (to be wise) and the phrase 'sapere aude' (dare to be wise). The phrase is associated with German philosopher Immanuel Kant, who promoted the use of reason as a tool of thought; an approach that underpins all Sapere's practice groups.

We build and maintain effective relationships as demonstrated by the volume of repeat work. Many of our experts have held leadership and senior management positions and are experienced in navigating complex relationships in government, industry, and academic settings.

We adopt a collaborative approach to our work and routinely partner with specialist firms in other fields, such as social research, IT design and architecture, and survey design. This enables us to deliver a comprehensive product and to ensure value for money.

About Energy Link

In 1996 the New Zealand electricity industry changed forever, leaving behind the days of central planning and embracing deregulation and competition. Energy Link was created by Managing Director, Greg Sise, to assist smaller players compete in the newly deregulated wholesale electricity spot market. In the years since, many things have stayed the same, but many more have changed and at an ever-increasing rate. Today, the future evolution of the electricity industry is undergoing unprecedented change as the high cost of energy and its impact on the climate, have created their own climate in which technology is driving change down to the lowest levels - your home. Energy Link has responded to these challenges since 1996 and is recognised as a leader in the fields of procurement, risk management and hedging for electricity, software and systems for managing energy.

About Chapman Tripp

Chapman Tripp's energy sector team is the leading team in New Zealand's legal market. We advise clients from across the sector on their most important and hardest projects, and help clients set their strategy as the New Zealand energy sector responds to the environmental, economic, and social aspirations of New Zealanders.

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