Hydrogen Storage as a Dry-year Solution

Modelling Undertaken for Firstgas Group

November 2022

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Definitions

The following abbreviations and acronyms may appear in this report.

100%RE	100% renewable electricity
CCGT	Combined-cycle gas turbine
Code	Electricity Industry Participation Code
DSR	Demand-side response (to spot prices)
EMarket	The model developed and used by Energy Link to perform the electricity market scenario modelling underlying Price Path and custom forecasts
GXP	Grid Exit Point
HVDC	High voltage direct current
I-Gen	Energy Link's model for determining when new generation plant is likely to be built
IPP	Independent power producer
LCOE	Levelised cost of energy
MDAG	Market Development Advisory Group
MBIE	Ministry of Business Innovation and Employment
MRDA	Must-run Dispatch Auction
NEM	National Electricity Market
OCGT	Open cycle gas turbine
OTA	Otahuhu grid node
PEM	Proton exchange membrane
PPA	Power purchase agreement
PHES	Pumped-hydro energy storage
ROI	Return on investment
ROX	Roxburgh grid node
SEV	Stored energy value
SLR	Supply of last resort
SRMC	Short run marginal cost
TPM	Transmission Pricing Methodology
TWAP	Time-weighted average price
WACC	Weighted average cost of capital

Disclaimer

In preparing this report, Energy Link has made predictions of the outcome of future events including, but not limited to, spot electricity prices, electricity forward and futures market prices, local and national demand for electricity, hydrological inflows to river systems, temperature and weather conditions, the nature of and prices in carbon and gas markets, and the bidding and purchasing behaviour of participants in electricity and other markets. Energy Link has made such predictions in good faith and Energy Link will not be held liable for the actual outcomes of the specified events, for the accuracy of its predictions or for any special or consequential damages or losses resulting in any way whatsoever from the purchase, consideration or use of Energy Link's forecasts.

Although the type of data provided in this report may be regarded as an essential input into the process of optimising hedging and other commercial strategies, unless otherwise agreed, this report in itself does not in any way constitute advice about hedging or other commercial strategies. Advice about hedging or other commercial strategies should take account of a number of other important factors and should be sought separately from Energy Link, if required.

How to Interpret our Forecast Prices

The headline forecasts that appear in this report (including in various charts) are typically (unless otherwise stated) either an average or median value taken from the large range of scenarios that we model. As such, none of the headline forecasts represent an actual single scenario. Weighted average forecasts are expressed as "expected prices" in the sense that if the forecast period is repeated hundreds of times then the prices should average out to the expected values. It is therefore coincidence if the price in any particular period turns out to be the headline value.

For planning and budgetary purposes, it is important to realise that prices could turn out substantially higher or lower, depending on what happens over the coming years. Percentile and other charts and tables in this report are intended to provide you with guidance as to the range of spot price outcomes, and to the assumptions underlying the spot price modelling.

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1 Introduction

In March 2021, Firstgas Group released a "plan for decarbonisation of its gas pipeline network in New Zealand" with the aim of blending hydrogen into the North Is natural gas network from 2030, with conversion to100% hydrogen by 2050. The plan stated this would be "supported by biogas and bioLPG to offer emissions reductions for all gas users."

Part of the release included a feasibility study for adding green hydrogen production and hydrogen storage on a large scale, large enough to support electricity generation in dry years[1].

Firstgas Group engaged Energy Link in July 2022 to model the operation of large-scale hydrogen storage, and to compare this to other scenarios currently being considered as the sector looks to move to 100% renewable (100%RE) electricity production, whilst supporting increasing electrification and ensuring an affordable and resilient system.

The key question to be answered was: how does an electricity system utilising large-scale hydrogen storage compare with other key alternatives in delivering the needs envisaged in 2050 across all three sides of the 'energy trilemma'. The results of this study are to inform where further investigation and development should be focussed.

Key objectives from the modelling include:

- assessing the pros and cons of a scenario using renewable ("green") hydrogen gas with storage versus other key alternatives to enable the electricity system to provide for the needs envisaged to 2050 across all three sides of the 'energy trilemma'[2].
- identifying and quantifying risks associated with not sustaining gas (renewable or otherwise) in the energy system, e.g. system resilience and vulnerability, market stability and volatility, and power price level.
- quantifying the storage needed to support peak demand, seasonal and dry-year supply constraints, and other operational requirements.
- outlining key benefits or issues that power-to-gas (including power-gas-power) could provide in an NZ energy system context.

The two key alternatives currently receiving attention in the public domain are the "MDAG Reference Case" and Lake Onslow Pumped Hydro Energy Storage (PHES).

1. **MDAG Reference Case**
   A potential solution in line with that modelled by Concept Consulting for the EA's Market Development Advisory Group (MDAG) where the existing hydro lakes are held higher than they are currently, resulting in substantially more spill than currently occurs. This is accompanied by an over-build of renewables (wind and solar, in particular), which results in substantial spill of wind and solar generation, and wind and solar capacity factors[3] less than plant capability. In this case Concept Consulting propose security of supply is maintained by up to 900 MW of peaking generators ("peakers") burning 'zero carbon-fuel'[4] and 400 GWh (electricity equivalent) of gas storage, along with large amounts of demand-side response (DSR)[5].

[1] It is common in the electricity sector to talk of dry years but in reality, dry periods typically do not extend beyond several months.
[2] Sustainability, affordability and security of supply.
[3] A generator's capacity factor is the actual output over a period divided by its theoretical maximum output. For example, if a wind farm generates 100 GWh over a year, when it could have generated 250 GWh based on its installed capacity, then its capacity factor is 100/250 = 40%. If an over-supply caused wind to be 'spilled' so that only 90 GWh was generated, then the capacity factor would be 90/250 = 36%.
[4] Gas produced by renewable processes, e.g. biogas or green hydrogen.
[5] DSR is demand that is voluntarily turned off or reduced, when the potential for a shortfall in generation, relative to demand, rises.

2. **PHES**
   A potential solution featuring Lake Onslow, as the large PHES located in the lower South Is, supplemented with the battery storage and DSR included in the MDAG reference case, but with no gas-fired generation whatsoever supporting the electricity system.

A scenario based entirely on the MDAG reference case was created, referred to in this report as the "over-build scenario". A large-scale hydrogen storage alternative future scenario was developed using the over-build scenario as the starting point, but excluding the green peakers present in the over-build scenario, adding hydrogen storage until hydro spill returns to currently accepted levels, and wind and solar capacity factors restored to values that do not reflect excessive spill. Hydrogen production was assumed to be in the North Is, close to the existing gas infrastructure including high-pressure pipelines and depleted gas fields, the latter to be used for hydrogen storage on a large scale.

The modelling was undertaken in real terms (2022 dollars) because the MDAG reference case was undertaken in real terms.

The modelling was undertaken in hourly mode for one year, 2050, using demand from the MDAG reference case.

2 Summary

The over-build scenario was created in Energy Link's *EMarket* model and adjusted to have it match the MDAG reference case, given differences between the models. Due to these differences in models, and other factors, it was not possible to obtain a perfect match, but the key attributes of the MDAG reference case were recreated for use in this scenario, and as base assumptions in the Onslow and hydrogen storage scenarios.

The over-build scenario featured 900 MW of gas-fired peakers.

All of the scenarios had storage additional to the existing hydro lakes; over-build scenario 400 GWh, Onslow 5,000 GWh and we initially modelled three hydrogen storage sizes of 1,000 GWh, 2,000 GWh and 3,000 GWh.

The 1,000 GWh hydrogen storage facility appeared to be less than optimal, as storage hit full or empty in a substantial number of the 91 inflow scenarios[6] modelled in each case. The 3,000 GWh storage option did not use all of the storage available, but the 2,000 GWh storage option appeared to make the best use of the hydrogen storage facility, with storage just grazing full and empty in a handful of inflow scenarios: as a result, unless indicated otherwise, this storage size was used to produce the results in this report. Nevertheless, it is likely that further optimisation of the storage, electrolyser and generation capacity in the hydrogen storage case is achievable.

Storage losses in the over-build scenario were assumed to be zero. The Onslow PHES was assumed to have 1,000 MW of generating and pumping capacity, with pumping efficiency of 75%, giving round-trip losses of 25%.

Hydrogen was assumed to be produced by electrolysers with 75% efficiency, and consumed by gas turbine-powered generators with average efficiency of 40%, which assumes burning the hydrogen in an open-cycle gas turbine, giving the hydrogen scenario round-trip efficiency of 30%, i.e. losses of 70%. Higher efficiency conversion to electricity may become cost-effective in future as, for example, fuel cell technology becomes cost-effective at grid-scale.

The water or hydrogen in storage requires a value to be put on it, so that generation can be offered into the spot market at an optimal price, and pumping (for Onslow) or electrolysis (hydrogen scenarios) can be bid

[6] To match historical inflows.

into the market at an optimal price[7]. *EMarket* optimises water values for the large hydro lakes and for PHES, and this algorithm was extended and generalised for use with hydrogen storage, and to calculate 'stored energy values' at any point in the simulated year.

The stored energy values form the basis of generator offers, and then pumping or electrolysis are bid at the stored energy value less the round-trip efficiency, i.e. 75% of the stored energy value (water value) for Onslow and 30% of the stored energy value for the hydrogen scenarios. In this way, storage is managed optimally and the generation-storage-charging system can respond dynamically to rapid changes in market conditions, e.g. peak versus off-peak prices during a day, or prices rising during a dry period.

The modelling results are summarised in Table 1 below. The colour coding indicates the relative performance, with green indicating best performance, yellow mid-range and orange the worst. The construction cost range for the Onslow scenario is wide, from $3.2 billion to $15 billion[8], so for the purposes of the table the mid-point value of $9.10 billion was used for the total cost and the annual costs.

The expected total cost of energy is the average spot price, plus the annual costs that are not recovered through the spot market divided by the total demand of 66 TWh; this assumes the additional cost is passed through to spot purchasers via an additional market mechanism, for example a levy.

Forecast supply of last resort is the average of the SLR with and without the HVDC winter outage[9].

All scenarios are 100% renewable but fugitive emissions from geothermal generation remain[10]. The emissions exclude emissions from the manufacture and delivery of equipment and the construction of new generation.

Table 1 – Results Summary

			Over-build	Lake Onslow PHES	Hydrogen Storage
Affordability	**Expected total cost of energy**	$/MWh	**135**	**124**	**113**
	New generation expected	MW	12,227	10,494	11,904
	Total cost (incl. new generation)	$bln	20.9	27.5	22.1
	Average spot price	$/MWh	134	119	113
	Annual costs not covered by net revenue	$mln/yr	70	335	-11
Security of Supply	**Forecast supply of last resort**	MWh/yr	**12,763**	**18,444**	**6,135**
	Supply of last resort without HVDC outage	MWh/yr	12,414	11,864	4,734
	Supply of last resort with HVDC winter outage	MWh/yr	13,113	25,024	7,537
Sustainability	**Emissions**	mln tonnes/yr	**2.04**	**1.97**	**1.99**
Other considerations	Spill from all sources (hydro, wind, solar, geothermal)	TWh/yr	6.5	2.6	1.8
	Spot price volatility	Std. dev. of annual prices	86	115	81

The results suggest that the hydrogen storage option would be a strong performer in terms of delivering benefits to the electricity market. In terms of affordability, the hydrogen scenario had the lowest spot price

[7] A price that accurately reflects the value of the stored energy given market conditions at the time.
[8] The higher end of the range includes an upgrade of the HVDC link between the north and south islands.
[9] The figures in the table may not appear to average or sum correctly due to rounding errors.
[10] Although not considered for this study, by 2050 it is possible that geothermals' fugitive emissions may be injected back into geothermal reservoirs.

and recovered its costs from spot market operations (which means it would not require any additional cost-recovery mechanism), hence it has the lowest cost to consumers.

In terms of security and reliability, the hydrogen scenario had the least SLR on average, and also during the prolonged winter HVDC outage scenarios used to test this aspect.

The hydrogen scenario had the lowest emissions and the least spill from all sources.

The Onslow scenario has the lowest build of new generation capacity, but based on the estimates available, unless Onslow's construction cost is at the lower end of the range (between $3.2 billion and $15 billion), it is likely to be the most expensive option, both in terms of total system capex (as shown above) and annual cost.

The over-build scenario has the lowest capital cost but is more expensive than the hydrogen scenario on an annual basis with the fuel cost set to $45/GJ, the value assumed in the MDAG reference case and behind the data in the table. The estimate for the over-build scenario does not include a component attributable to fuel storage.

Given the cost estimates available, and due to its location in the North Is, the 2 TWh hydrogen storage option covers its annual costs through its net spot revenue, defined as generation revenue less electrolyser electricity costs.

A hydrogen storage solution also offers the potential for it to be scaled up in stages, and optimised across the combination of storage, electrolyser capacity and generation. Furthermore, this study only looks at the merits and drawbacks of hydrogen production and storage to support the electricity system, but there may be further benefits from scaling up hydrogen production to supply existing and future gas consumers.

There is high uncertainty over the cost of the Onslow scenario, and developing Onslow would have substantial and obvious environmental impacts which the over-build scenario and hydrogen storage would not have.

The over-build scenario has the lowest total cost of new generation and storage, although there is uncertainty over the costs associated with the 400 GWh of fuel storage, which are not included in the estimates in this study.

Taken overall then, large-scale hydrogen storage has a number of attractive features, and may also be cost-effective for electricity-related storage, relative to the alternatives modelled. There is already work underway in New Zealand to investigate the feasibility of large-scale storage of hydrogen in depleted natural gas fields, and this study confirms that a hydrogen storage strategy warrants further investigation.

3 Methodology

The first step in the methodology was to reproduce the MDAG reference case, to the extent possible, using our *EMarket* electricity market model, and this became the over-build scenario. The alternative would be to use the results of the MDAG modelling directly, but then this could introduce differences due to different models being used for the MDAG scenario on one hand, Onslow and hydrogen storage on the other. In addition, much of the data required to set up basic MDAG assumptions was not available to us[11].

Energy Link's *EMarket* model also:

- used 91 years of inflow (weather) scenarios, whereas MDAG had 86;
- used 40 years of synthetic (and actual where available) wind and solar data, whereas the MDAG modelling used 18;

[11] An example is the details of the model demand profiles used in the MDAG modelling.

- has automatic, optimised water values for large hydro systems, whereas the MDAG modelling used manually-entered water values;
- ran exclusively in hourly mode, whereas the MDAG modelling was run in weekly mode, with samples run in hourly mode;
- calculated transmission losses dynamically, based on a detailed grid model, whereas the MDAG modelling has static losses which are included in demand;
- had 220 nodes in its grid model, whereas the MDAG modelling had two nodes, one for each of the North and South islands[12].

The above does not imply that one model is right and one is wrong, as all models have their own characteristics which can lead to significantly different results given the same set of inputs. Nevertheless, the differences in the model setup, inputs and internal algorithms lead to differences in results. As a result of this, the first step, reproducing the MDAG reference case using *EMarket*, meant that all scenarios modelled for this study would have a common base, i.e. the Energy Link's version of MDAG's reference case, referred to as the "over-build scenario".

Due to differences in models, and probably also small differences in the input assumptions for the two models, to reproduce the results of the MDAG reference case exactly would have taken more time than was available for the study. Instead, there appeared to be trade-offs between, for example, accurately reproducing the hydro spill figures and at the same time, obtaining matching average prices. However, the over-build scenario was considered close enough for the purposes of this study, and its use as the basis for the Onslow and hydrogen scenarios allowed valid comparisons between the three scenarios.

3.1 Over-build scenario

The over-build scenario was created for 2035 and 2050, with the following assumptions:

- demand follows the Climate Change Commission's 'demonstration path'[13] and totals 66 TWh per annum in 2050, made up of 45 TWh of underlying demand excluding Tiwai, 8 TWh of electrification from conversion of process heat, and 12 TWh from EVs;
- Tiwai Pt aluminium smelter closed;
- the seasonal pattern of underlying load and low temperature process heat follows historical patterns;
- new food processing heat follows a summer oriented dairy pattern;
- EV load has a slightly summer oriented profile, with load shifting;
- 800 MW of demand-side response (DSR) in tranches priced from $700/MWh to $1,500/MWh;
- gas turbines fired with "green gas" (900 MW installed) costing $45/GJ;
- limited storage of gas (400 GWh);
- demand-side response (DSR) of 800 MW;
- hydro lakes held higher in summer to provide buffer for winter, leading to significantly more spill than we have in the market today;
- over-build of wind, solar and geothermal generation.

DSR is demand-side response to price, made available on a voluntary basis in the normal course of events, but made available at a price. DSR is effectively negative demand, in the same way as generation, so DSR is actually modelled as generation, offered into the market at the prices noted above.

The version of the over-build scenario created for this study, modelled in *EMarket*, has some differences to the MDAG reference case, listed below.

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[12] This is inferred, as the number of nodes was not stated in the MDAG modelling report. We think the modelling also used adjustment factors for reginal price adjustments.
[13] As it was early in 2022.

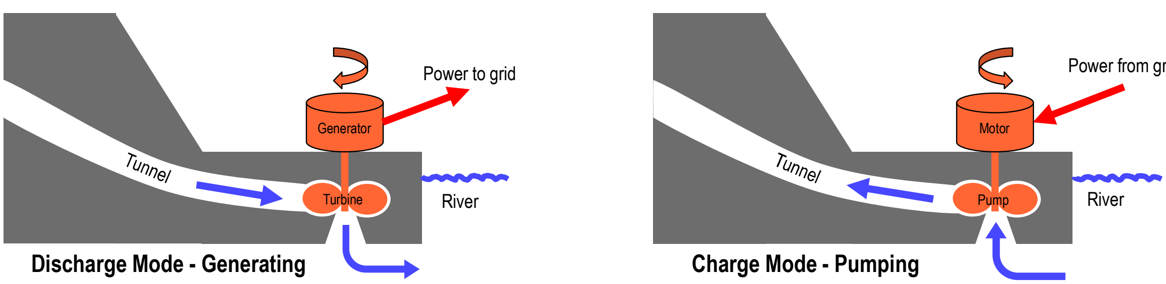
1. The mechanism for large scale demand shifting in the MDAG model is unclear and this resulted in limited demand shifting in the *EMarket* model. As a result, *EMarket* peak demand is higher than the MDAG reference case, which results in higher pricing in the *EMarket* model during the winter months and also in increased price volatility.
2. Some additional restrictions were placed on the thermal peakers to ensure that storage levels remained similar to the MDAG results.
3. There was no flexibility assumed in the output of new geothermal plant in *EMarket*.
4. Spill values were similar to the MDAG results;
    a. hydro; MDAG – 3.7 TWh, *EMarket* – 3.9 TWh
    b. wind; MDAG – 1.9 TWh, *EMarket* – 1.9 TWh,
    c. solar; MDAG – 0.6 TWh, *EMarket* – 0.6 TWh
5. EV profiles were modelled as using the 60% overnight optimised and current mix profile.
6. Roof-top solar had no adjustment for batteries and used a typical solar profile.

3.2 Onslow PHES

Energy Link added PHES capability to *EMarket* in October 2020 and has used this capability in a number of modelling exercises since then. The basic operation of a PHES facility is to pump water into an elevated reservoir when conditions are such that there is a surplus of water available in the intake water source, and then to generate using the stored water when there is a shortage of electricity.

The pumps and generators are actually the same pieces of equipment. The best way to think of this is as a generator which generates and supplies to the grid, but when pumping is required, it takes power from the grid so that it operates as a large motor, which turns the turbine in the reverse direction, to move water uphill to the storage reservoir. The two modes are shown below, keeping in mind that these are two pictures of the same piece of equipment, which can operate as either a generator or a pump, but not both at the same time.

Figure 1 – PHES Operating Modes



The pumping mode is less efficient than the generating mode, so every PHES facility has an efficiency factor which must be applied to the charging (pumping) phase relative to the discharging (generating) phase. The generator is assumed to have a capacity of 1,000 MW, which is also the pumping capacity. Our assumption is that pumping is 75% efficient, so if the maximum flow for generation is 240 cumecs, for example, then 75% pumping efficiency means the maximum flow for pumping would be 180 cumecs.

Ideally, to compare directly with the over-build scenario, the capacity would be set to 900 MW, but this would be below the current credible range for Onslow's generating capacity. The most detailed analysis of Onslow, outside of the NZ Battery project, is contained in a PhD thesis[14], which uses 1,300 MW for the capacity. We are also aware of credible analysis using 1,000 MW, but no lower.

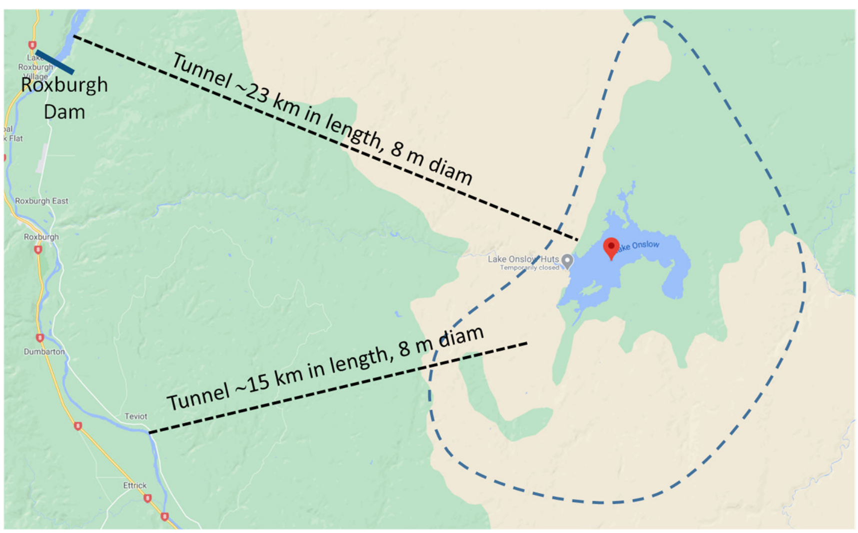
[14] *Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand's South Island.*, PhD thesis, Majeed 2019

The Onslow basin is near Roxburgh in Central Otago, as shown below, and is elevated about 700 m above the Clutha River. There is already a dam and man-made lake in the basin, which generates about 135 GWh per annum on average.

Figure 2 – Existing Lake Onslow

The Onslow proposal could see total storage as high as 10,000 GWh if the storage reservoir were extended to the nearby Mannorburn and Greenland reservoirs, but it would be more likely to be of the order of 5,000 GWh storage and covering the area shown below.

Figure 3 – Proposed Lake Onslow



Water would be extracted from, or discharged via a tunnel, which could terminate either adjacent the existing Lake Roxburgh or downstream of Lake Roxburgh. The most likely option, modelled in this study, appears to be 5,000 GWh of storage, with a 15 km tunnel terminating downstream of Lake Roxburgh.

There was no additional peaking generation modelled in the North Is in the Onslow scenario, so the only alternatives available to help meet peak demand in the North Is were the DSR assumed in the over-build scenario, along with 'supply of last resort' (SLR).

SLR represents an aggregation of emergency demand-side response, extra generation provided by a range of small generators, and ultimately non-supply (forced outage). The typical configuration in *EMarket* for small generators is a fixed profile based on historical patterns of generation, e.g. it might be a small hydro station. But we know that some small generators will respond in times of scarcity and high prices, and rather than attempt to model this over all small generators in the model, this response is aggregated into SLR.

Under the scarcity pricing rules introduced in 2012, when there is a shortage of generation offered into the market relative to demand, spot prices are set at between $10,000/MWh and $20,000/MWh, which suggests that SLR should be offered into the market at a value of least $10,000. However, emergency DSR and additional output from small generators is aggregated into SLR, and so it is actually offered in *EMarket* at the lower price of $2,000/MWh. which puts it higher in the offer stack than DSR. The same SLR price was used in all scenarios.

3.2.1 Water Valuation

Experience shows the general understanding of how stored water in Onslow would be valued, is relatively poor. A typical starting assumption is that the Onslow operator would set prices at which they generate, and prices at which they would pump, with the overall objective being to manage dry year risk. For example, an fixed price could be set at which Onslow would generate during a dry year, and a lower fixed price could be set at which Onslow would pump water to restore storage after a dry year.

But there are many problems with this approach. The first and arguably most important issue is that no one in the electricity market knows that it will be a dry year ahead of time. Weather forecasters might predict a prolonged La Nina period, for example, with low inflows in the existing southern hydro lakes, but longer-term forecasts are nowhere near as accurate as short-term[15] forecasts. Even if the forecast is "correct", one or two large storms can top the lakes up very quickly at any time of the year.

The Onslow operating strategy should therefore accommodate uncertainty in weather, and probably other factors as well.

The second key issue is illustrated nicely by recent events in the National Electricity Market (NEM). The market operator, AEMO, suspended the market back in June when a long-standing price cap mechanism caused prices to be capped below the marginal cost of generating with gas, which meant that gas generators did not bid to run (as they would run at a loss) and a shortage resulted.

This was an example of what happens when an arbitrary fixed price is introduced into a market; arbitrary in the sense that it is not based on the drivers underlying the market day-by-day and hour-by-hour. In the case of the NEM, the price cap was developed during an earlier period when gas prices were significantly lower than is the case now.

A good example for Onslow, is illustrated by the contrast between be a situation in which Onslow storage is high and other hydro lakes are also above expected storage[16], with spot prices relatively low. If Onslow's fixed offer price[17] for generation is relatively high, then it would not generate but might continue to pump in order to increase storage, ready for the next dry year.

But then if it was low, for whatever reason, and other hydro lakes were well below where their respective storage would be expected for the time of year, and also falling faster than expected, then the same generation offer price might see Onslow storage drawn down rapidly until it was literally empty, leaving nothing in reserve if the dry conditions continued.

[15] Out to ten days, for example.
[16] Expected storage given time of year.
[17] To generate, Onslow (and all other generators over 10 MW) would offer to generate an amount in MW at a price in $/MWh. To pump, Onslow would bid to pump an amount in MW at a price in $/MWh.

Likewise, if there was a surge in demand growth over a period of one or two years, then if Onslow's operator did not modify its strategy, it could end up running Onslow storage too low because market spot prices would rise due to the additional demand.

These simple examples show that, at the very least, Onslow's offering and bidding strategy should adjust to market conditions as they change over time.

There is already a well-established method for operating hydro lakes in New Zealand[18], which revolves around the concept of 'water value', albeit with a number of variations developed by hydro lake operators to suit their particular corporate requirements, e.g. attitudes to risk.

By definition, the water value is the expected future value of the next unit of stored water in a hydro lake, that could be used to generate. Strictly speaking, it only applies at the margin, i.e. it is a marginal water value, and not to the entire contents of a lake.

Water values are calculated by mathematical optimisation algorithms that typically take account of demand, other hydro systems (storage lake and downstream power stations), other generation, operating constraints such as reservoir size and generating capacity, uncertainty in inflows to hydro lakes, risk aversion, and other factors.

So, for example, if the water level in Onslow remained constant over a period, but other lake levels fell below expected levels, then the Onslow water value would rise in expectation of spot prices being higher as a result of the fall. Water values are typically intended to maximise risk-adjusted revenue, but an alternative and very useful way to think about water values is that they are intended to optimally ration the use of stored water taking into account the other generation that hydro generation displaces[19].

The *EMarket* model has water value optimisation for all existing large hydro lakes and for Onslow, and these ensure the best use is made of Onslow's storage capacity given its storage, the storage in other hydro lakes, along with expected demand and, in the 100%RE case, the value put on DSR and SLR.

Figure 4 – Onslow Water Values

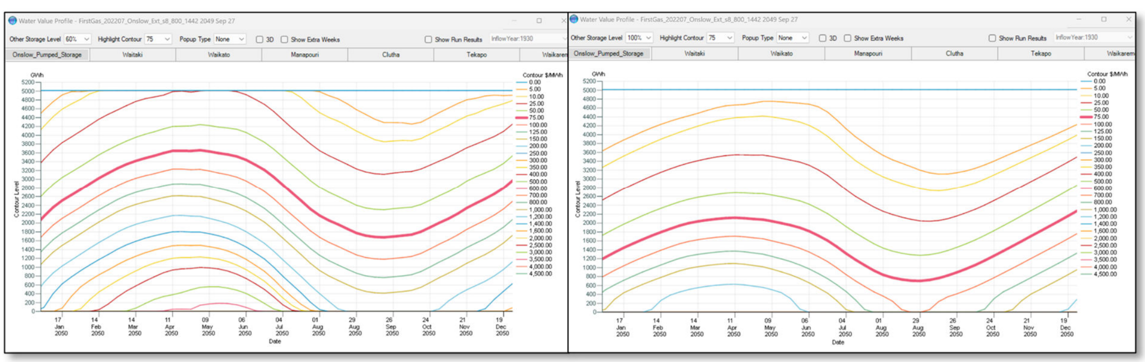


Figure 4 above shows two examples of water values for Onslow. On the left, are the water values when all other hydro lakes are 60% full on average. The vertical axis is storage in Onslow and the horizontal axis is time of year. The thick red line is the $75/MWh water value contour, so at any point in the year, if Onslow storage is sitting on this contour when all other storage is 65% full on average, then Onslow's water value is $75.

[18] Developed and refined over the years, starting in the Electricity Corporation in the mid to late 1980s.
[19] Large hydro generators do individually have some market power, but it has relatively little scope to influence hydro revenues, and the use of market power is monitored by the EA. So, for example, historically pure hydro generators have faired better during wetter year with lower prices, compared to drier years with higher prices.

On the left, are the water values when all other lakes are full, and now the $75 contour is lower than it was with other lakes 60% full: with this much water available for generation, the value of water in Onslow has fallen relative to the left-hand chart, and storage will be much lower before it has a value of $75.

The shape of the water values for the existing hydro lakes are less regular than the above, as they are highly influenced by historical inflow sequences, since this is where they get their water from, i.e. natural inflows, which are highly variable, with a handful of years tending to set the extremes. But for large storage facilities, the water values tend to be smoother and more evenly spaced because they source water by pumping, over which they have a high degree of control.

3.2.2 Operating Strategy

It is assumed that Onslow would be offered and bid into the spot market in order to generate (offers) and pump (bids). The water value provides the operator of the PHES with the basic information to use in its offers to generate, and the modelling assumes that Onslow offers to generate at its water value, expressed in $/MWh. This is an optimal strategy in the sense that Onslow should generate whenever the spot price it receives the Roxburgh nodes is equal to or greater than the expected future value of the next release of water into the generators[20].

The dispatch algorithm in *EMarket*, which matches the algorithm used in the real spot market, decides how much of Onslow's offer to accept[21], and calculates the prices at all nodes. As more generation is dispatched, the price at the Roxburgh node, where it injects into the grid, falls relative to other nodes, which might limit the amount that is dispatched.

Onslow's operator bids into the spot market to pump, and the value put on these bids is 75% of the water value, i.e. the "bid-offer spread" is 25% for Onslow. If Onslow is dispatched to pump at this price, then it is recharging at or below its current water value, which is expressed in terms of generation.

The bid-offer spread ensures that Onslow cannot be dispatched for pumping and generation at the same time but, assuming the plant is capable, its dispatch can change from pumping to generating in a short period of time, e.g. it might charge overnight and generate during the day, if prices warrant.

3.2.3 HVDC Link

The Onslow PHES scenario is less than ideal in terms of location, as ideally it would be in the North Is where the major portion of demand is located. The NZ Battery project is looking at North Is locations for PHES, but there is as yet no indication if any suitable sites are available.

With Onslow in the South Is, the capacity of the HVDC link becomes a major issue, both in times of normal supply, but even more so during periods when the HVDC link operates at lower-than-normal capacity, for example, as it did from 7th January to 28th March 2020, while the conductors on the section of the link from Churton Park to Haywards were replaced.

Transpower is already looking to replace the Cook Strait cables that form part the HVDC link, later this decade, which could see the northward capacity increase from 1,200 MW to 1,400 MW.

However, the capacity of the HVDC link, even once upgraded to 1,400 MW when the Cook Strait cables are replaced, limits Onslow's abilities to provide energy to the North Is during the morning and evening peaks, particularly during dry periods. As a result, Transpower has foreshadowed the need to add another pole of 700 MW capacity to take the total HVDC capacity to 2,100 MW at the Benmore end when sending power northward, and 1,550 MW south from Haywards[22].

[20] This illustrates how the water value is the opportunity cost of generation.
[21] Likewise for all other generators.
[22] *Net Zero Grid Pathways 1 Major Capex Project (Staged) Investigation*, *Shortlist consultation*, Transpower, 30 June 2022.

The Onslow scenario assumed the additional pole, running from Roxburgh to Huntly, thus avoiding the need to upgrade the existing core grid infrastructure in both islands and, just as importantly, to add additional redundancy to the HVDC link.

3.3 Green Hydrogen

The underlying assumption in this scenario is that hydrogen can be stored in depleted natural gas fields, either on or offshore Taranaki, in large quantities. The concept of gas storage is not new, as it already exists in the Ahuroa natural gas field, where gas can be pumped from the natural gas transmission pipeline, owned and operated by Firstgas Group, into the Ahuroa field, also owned and operated by Firstgas Group, then extracted at a later date for reinjection into the pipeline and thence to its ultimate end-user.

It is not confirmed that hydrogen can be stored on a similar scale as Ahuroa. A team from the University of Canterbury was engaged by Firstgas Group to undertake a pre-feasibility study[23] and the team has now secured $11.8 million from the MBIE-funded Endeavour Fund (MBIE funded) to undertake detailed research over a five-year period.

A further assumption is that the gas transmission pipelines can be converted to carry pure hydrogen. Firstgas Group undertook work[24] on this issue and believe it is feasible, initially with a mix of 20% hydrogen and 80% natural gas, but ultimately 100% hydrogen.

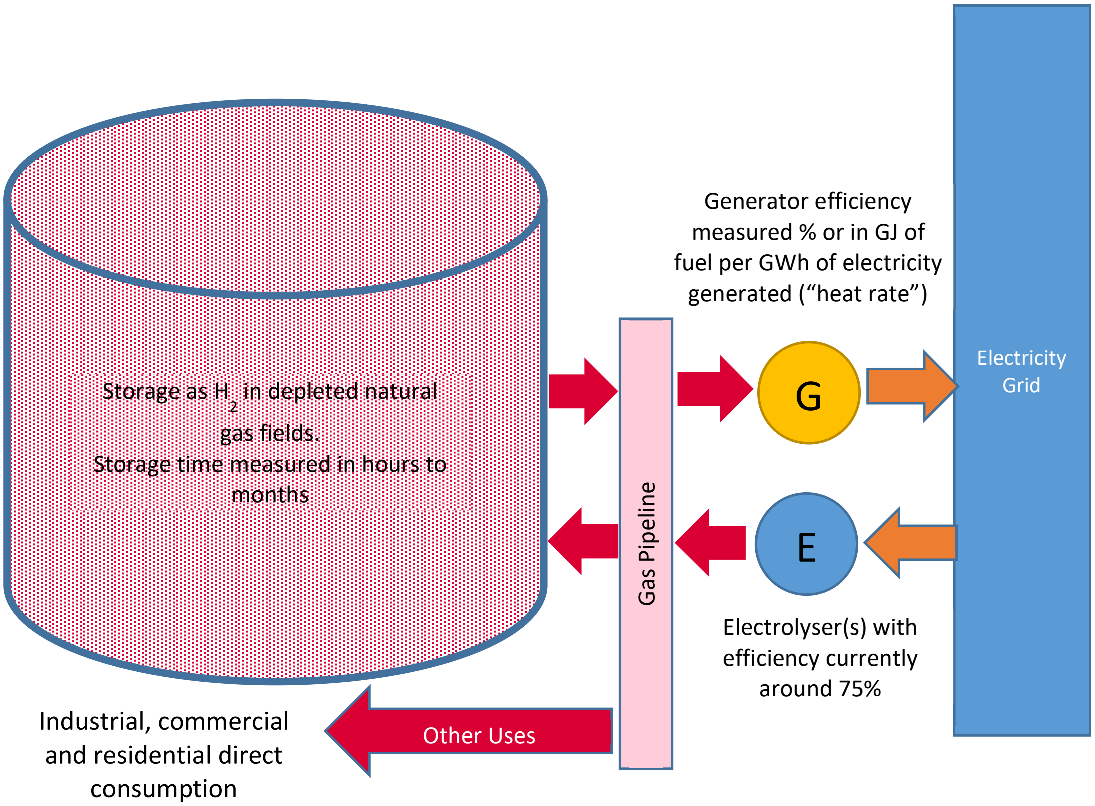
Figure 5 shows a schematic of the configuration modelled in this scenario. Hydrogen gas is produced in electrolysers (‘E’ in the diagram) at an efficiency of 75%, using electricity from the national grid, injected into the converted gas transmission pipeline, transported to the hydrogen storage facilities[25], and injected into storage. Alternatively, hydrogen could be transported by pipeline directly from one or more electrolysers to one or more generators (‘G’ in the diagram).

But stored hydrogen would be used by reinjecting hydrogen into the pipeline, transported to one or more generator(s) that require gas, where it would fuel the gas turbines to produce electricity.

The diagram shows additional uses of gas which include mainly industrial applications that are difficult to convert to using electricity directly, including steel production, cement production and chemical production. It is also conceivable by 2050 there might be smaller gas consumers who would be prepared to pay a premium, for whatever reason, to use hydrogen instead of electricity in certain applications. Either way, the hydrogen modelling focused entirely on electricity production, and additional uses were not considered. But if significant other uses remained, or developed in future, then these would help to pay for hydrogen-related infrastructure including hydrogen storage, gas pipelines and electrolysers.

[23] https://gasischanging.co.nz/assets/uploads/Underground-hydrogen-storage-Firstgas-report-March-14-2022-003.pdf
[24] https://firstgas.co.nz/wp-content/uploads/Firstgas-Group_Hydrogen-Feasibility-Study_web_pages.pdf
[25] We only modelled one storage facility, but there is no reason why there could not be multiple storage facilities, e.g. enough in number and capacity to make up the total required.

Figure 5 – Green Hydrogen for Electricity Generation



The electrolysers are assumed flexible enough to respond to rapid changes in their dispatched levels, which currently means they are likely to be based on proton exchange membrane (PEM) technology.

The generators are assumed to be open-cycle gas turbines (OCGTs), fully configured to burn hydrogen. It may be that one or more existing natural-gas-fired peaking generators can be converted cost-effectively in future, but we assumed the modelled gas peakers would be purpose-built for hydrogen combustion. These peakers typically have efficiencies in the 35% - 40% range[26].

It would also be possible to use combined-cycle gas turbines (CCGTs), which have a significantly higher efficiency than open-cycle gas turbines (CCGTs), but OCGTs are significantly cheaper to build than CCGTs and are typically used for peaking applications such as those modelled.

Nevertheless, there is a possibility that one or more hydrogen-powered CCGTs could be part of the generation mix in future, and so the efficiency assumed for the gas peakers was set at the higher end of the range, i.e. at 40%.

[26] All efficiencies are "higher heating value" figures.

The combination of 75% electrolyser efficiency and 40% generation efficiency means that the round-trip efficiency of electricity production and generation is 30% = 0.75 × 0.40 which is significantly lower than the 75% for Onslow PHES.

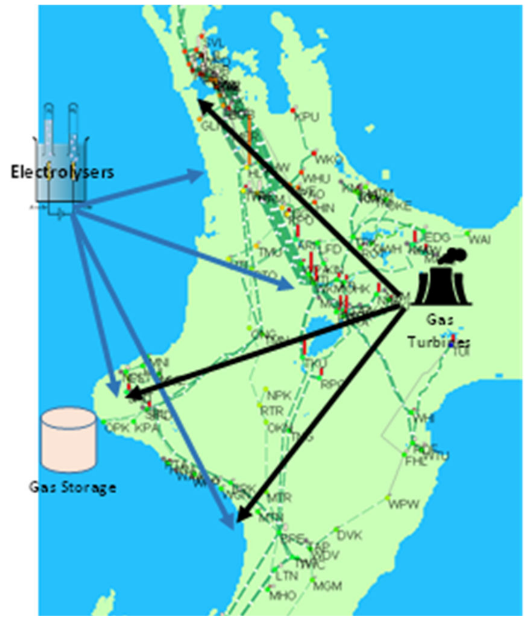
It might be possible to significantly increase the round-trip efficiency, either now or in the future, by optimising the overall hydrogen configuration, e.g. if electrolyser efficiencies increase, or if more efficient technologies than PEM can be used, or if alternatives to gas peakers become available.

On the latter point, it might in future be possible to use grid-scale fuel cells, which can operate at efficiencies of 60% or possibly higher, though at the present time, cost-effective fuel cells are not available at the scale of generation required in the hydrogen scenario.

Some relatively arbitrary decisions were required prior to modelling the hydrogen scenario, including the capacity and location of electrolysers and generators.

Three locations were chosen for each, as shown in Figure 6. The locations were chosen primarily based on being in relatively close proximity to both the electricity grid and the gas transmission pipelines. These locations are also unlikely to require major grid upgrades to support this level of new demand and new generation[27].

Figure 6 – Modelled Configuration



Electrolysers also require an adequate supply of water of around 10 litres per kg of hydrogen, currently assumed to be fresh water[28]. New Zealand has an ample number of rivers that could be used to supply this water, so the total water requirement is not large in the overall context, but the issues around obtaining access[29] to water were not considered in this study.

The total generation and electrolyser capacity was set up to be directly comparable to the Onslow configuration, with 1,000 MW of peaking generation. On the other side, to give the same charging rate as Onslow (in electricity terms, after accounting for the different round-trip efficiencies), the total electrolyser capacity was set at 2,500 MW.

The hydrogen storage configuration was not optimised during this study, but further modelling could explore a number of key optimisation opportunities, including:

- whether, with large-scale storage available, the electrolysers need to be highly flexible, e.g. it may be that they could operate at relatively stable levels, allowing higher efficiency technologies to be used, with the fluctuations in hydrogen demand handled primarily through use of storage;
- how much electrolyser capacity is actually required given the total demand for hydrogen across all uses;
- how much generation capacity is actually required to meet demand during dry years and peak periods on winter and other days.

The modelling assumptions were otherwise left as they were in the over-build scenario, although the gas peaking capacity was set 100 MW higher than in the over-build scenario, as described above.

[27] Another of looking at the grid issue, is to assume that plant would be sized with minimization of grid upgrade costs as a key consideration. So, for example, the ideal configuration might be a larger number of smaller electrolysers and generators, dispersed more widely on the grid.
[28] Cost-effective sea water electrolysis might be possible at scale in future.
[29] Electrolysers would require resource consent to use water, and there are already many competing uses for fresh water.

Three values for the hydrogen storage were tested: 1,000 GWh, 2,000 GWh and 3,000 GWh, where these values are expressed in generated electricity terms, i.e. the amount of hydrogen storage has a much greater energy content than these values, as shown below. The mass calculations in Table 2 use an energy content value of 142 GJ per tonne[30].

Table 2 – Hydrogen Storage Values

	Units	1,000 GWh	2,000 GWh	3,000 GWh
Electricity storage equivalent	GWh	1,000	2,000	3,000
Energy content of storage hydrogen	GWh	2,500	5,000	7,500
Energy content of storage hydrogen	PJ	9	18	27
Mass of hydrogen stored	tonnes	63,380	126,761	190,141

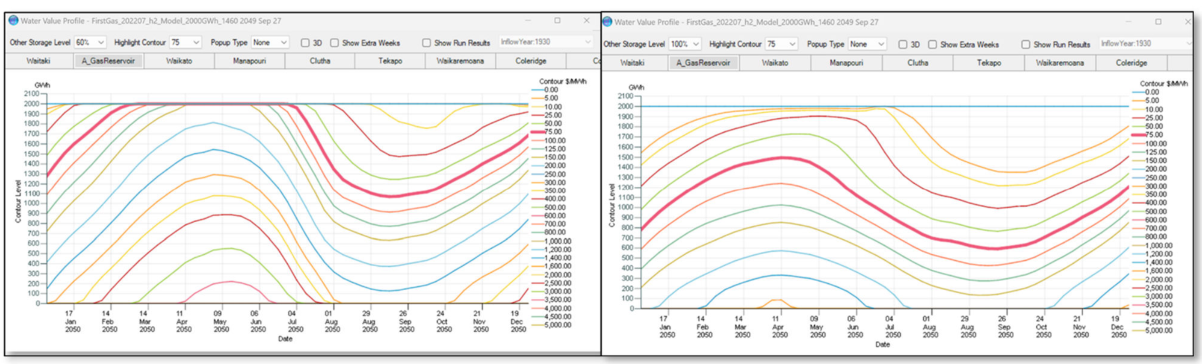
3.3.1 Stored Energy Valuation

Section 3.2.1 on Water Valuation looked at how Onslow would value water in storage and use this in optimally managing its market operations. Exactly the same concept applies to stored hydrogen, except that now the expected future value of hydrogen in storage is not a water value but a 'hydrogen value', or in generic terms a 'stored energy value' (SEV).

As noted above, the water value and the SEV are actually marginal values in the sense that they apply to the next increment of generation and not to all of the energy stored in a reservoir.

EMarket optimises and calculates SEVs for stored hydrogen using the same algorithm as it does for water values, just with different parameters, as shown below in Figure 7.

Figure 7 – Hydrogen SEVs with 2 TWh Storage



3.4 Other Common Assumptions

Where possible we used the MDAG assumptions across all models:

- the demand, demand profile, embedded solar, electrification and EV demand were the same in all scenarios;
- grid modelling and upgrades were the same in all scenarios, with the sole exception of the HVDC capacity in the Onslow scenario;
- with the exception of the HVDC limits, the grid was run unconstrained.

[30] Based on higher heating value and typically expressed as 142 MJ per kg.

3.5 New Generation Builds

All scenarios required new generation to be built to serve the additional demand forecast to be in the market in 2050, and to cover the retirement of fossil-fuelled generation; Energy Link's I-Gen model was used for this task.

I-Gen has a list of possible new generation projects, and each project has an estimated LCOE, which may change over time based on assumptions for inflation and technology learning curve effects, and other data including its location on the grid. The LCOE is defined as the constant average annual electricity price attained by the plant over its lifetime that just achieves target RoI after covering all cash costs. I-Gen forecasts spot prices in 15 regions, and looks for opportunities to build new plant when the forecast price exceeds the LCOE of a project, at which point the project is built.

This creates build schedules for each scenario, which are then run through *EMarket* so the financial performance of each new project can be checked. This may lead to a rerun of I-Gen with price forecasts updated from *EMarket*, so creating the build schedules is an iterative process, but it is designed to simulate the process that developers work through in the real market as they look to build a project.

The final build schedule for each scenario should only include new generation that meets its revenue RoI targets once built, and no more, i.e. if one more plant was built then it would not achieve its target RoI. This is not an exact process because generation investments are typically large so that projects in the build schedule might do better than just meeting their RoI target, but adding one more project causes many projects to fail to meet their targets. As a result, some scenarios might have a slightly more 'optimal build' than others.

Figure 8 shows the new builds for all five scenarios, including the three options for hydrogen storage and the total installed MW are shown in Table 3 below. Onslow has the lowest build by 1,140 MW relative to the hydrogen scenarios, and it is 1,733 MW lower than the over-build scenario's build.

Figure 8 – New Generation Installed Capacity

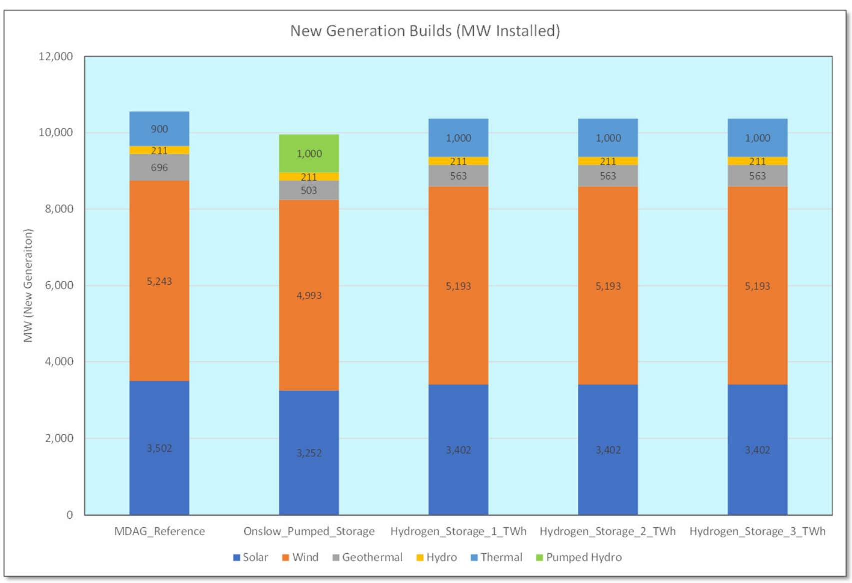


Table 3 – Total New MW Installed

Scenario	MDAG_Reference	Onslow_Pumped_Storage	Hydrogen_Storage_1_TWh	Hydrogen_Storage_2_TWh	Hydrogen_Storage_3_TWh
New MW Installed	12,227	10,494	11,904	11,904	11,904

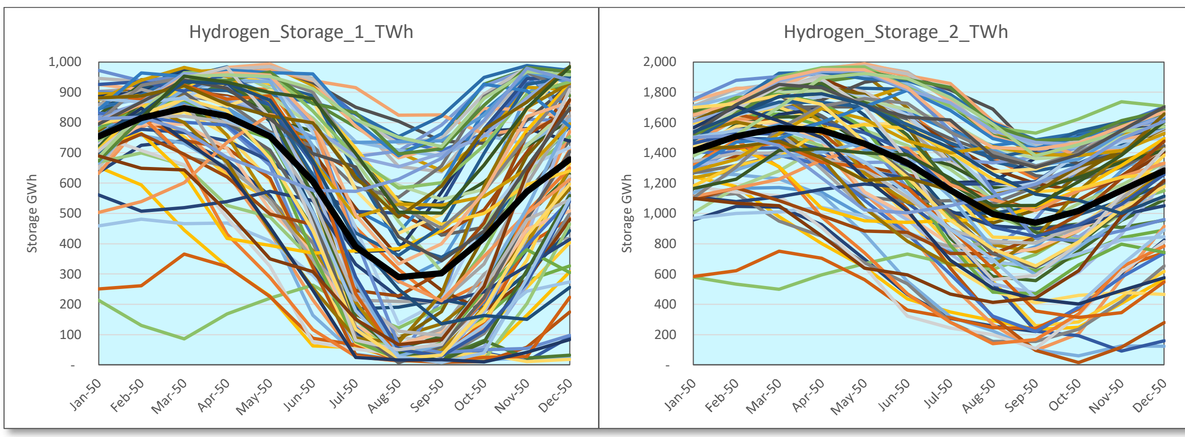
4 Results

This section looks at the detailed results of the three scenarios, which are used in section 5 where cost estimates are presented.

4.1 Hydrogen Storage Capacity

The three storage sizes were modelled initially to determine if there are any obvious limits to the amount of storage that would be economic. The storage 'trajectories' from all 91 inflow scenarios are shown in the two figures below, alongside the equivalent for the Onslow scenario. The modelling included adjustment of the starting storage value in each inflow scenario year to match the final storage value at the end of the previous inflow scenario year, thus minimising the impact of storage starting conditions[31].

Figure 9 – 1 and 2 TWh Storage Trajectories[32]



With 1,000 GWh of hydrogen storage (chart at left above) storage trajectories regularly hit the top and the bottom of the hydrogen storage facility. Unlike the existing hydro lakes, these storage facilities (and also PHES) are not likely to spill gas, because then the facility is full, it simply stops charging.

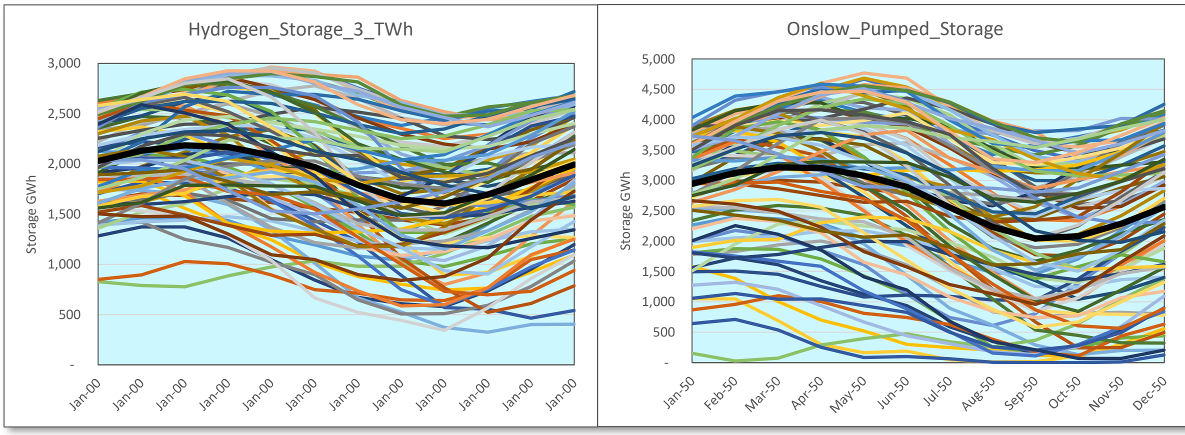
The existing hydro lakes also continue to generate even when at zero storage because they have natural inflows, whereas these storage facilities stop providing water or gas because there is no water or gas left.

The 2,000 GWh storage facility does better, and storage just grazes top and bottom in just a handful of inflow scenarios.

By the time we get to 3,000 GWh of storage, shown in Figure 10 below, there is more storage than can be economically used, and storage never falls below about 300 GWh.

[31] If the same starting storage value were to be used across all inflow scenarios, this would distort the results, especially in the first half of the year.
[32] For convenience, the charts use TWh units instead of GWh units, so as to conserve space on the charts. 1 TWh = 1,000 GWh.

Figure 10 – 3 TWh and Onslow Storage Trajectories

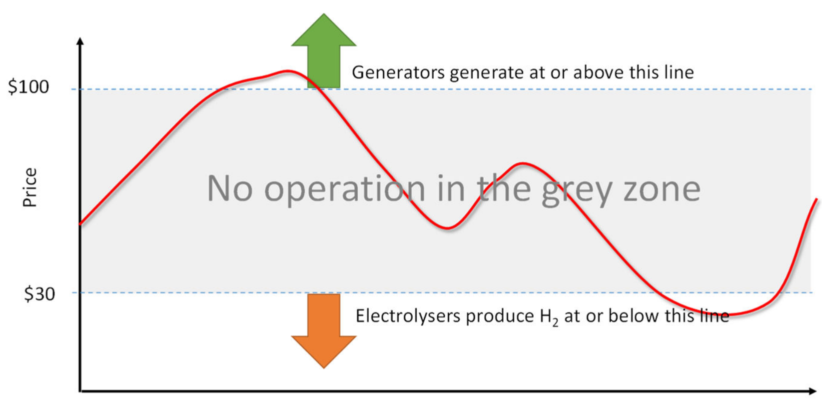


The storage in the Onslow scenario is 5,000 GWh but here, storage hits bottom in many scenario, and gets within 230 GWh of being full in one scenario: this raises the question, why does hydrogen storage not make use of more storage?

Most of the answer to this question is that the relatively low round-trip efficiency in the hydrogen scenario, 30% compared to Onslow's 75%, means that the hydrogen scenarios do not have as many opportunities to charge economically.

As described in section 3.2.2 on Operating Strategy, the bid-offer spread is set by the round-trip efficiency, so in the case of hydrogen storage it is 70% of the SEV at the time. For example, suppose the SEV is \$100/MWh, then Figure 11 below shows that generation would be offered at \$100/MWh and dispatched when the spot price at Roxburgh is \$100/MWh or greater. The electrolysers would bid \$30/MWh (70% of \$100) and would be dispatched to consume when the spot price at Roxburgh is at or less than \$30/MWh. The region between \$30 and \$100 is a 'grey zone' in which there would be no hydrogen-fired generation nor production of hydrogen[33].

Figure 11 – Bid-offer Example



Given hydrogen's significantly wider bid-offer spread, if all other things were equal, the electrolysers would have less opportunity to charge the storage facility compared to Onslow, and likewise for generation.

[33] This is a simplification because inter-nodal price differences cause the three electrolysers and three generators to operate differently, so the grey zone would in fact be 'smeared out'. In the real market, constraints and contracts not modelled might cause consumption and generation at prices that do not exactly match the SEV of the storage hydrogen.

Other things are not, in fact, equal, which tends to dampen out some of the effect. For example, whenever a storage facility charges, be it Onslow or electrolysers, it tends to raise spot prices, and vice versa for generation, so Onslow tends to smooth out intra-day and intra-week prices more than occurs in the hydrogen scenario[34].

Another key difference is the location of the two storage solutions. Hydrogen storage is located in the North Is, where demand is highest, and hence has lower transmission losses than Onslow: Onslow's larger storage volume and South Is location require larger HVDC flows than in the hydrogen storage scenarios, adding transmission losses into Onslow's round-trip efficiency.

The results in the following sections are all taken from the 2,000 GWh storage scenario for hydrogen, as it appears this might be close to an optimum storage value for hydrogen. However, this is not a firm conclusion from the modelling because no attempt was made to optimise electrolyser and generation capacity.

4.2 Spot Prices

Figure 12 shows spot prices, averaged over all inflow scenarios, by month, for the Benmore and Otahuhu nodes and shows how the seasonal price profile changes significantly with large amounts of storage. Storage tends to charge during the periods over lower demand (spring and summer) and to discharge during the months of higher demand (autumn and winter). The effect is a little more pronounced with Onslow with its 5,000 GWh of storage compared to hydrogen storage of 2,000 GWh.

Figure 12 - Monthly Average Spot Prices at Otahuhu and Benmore

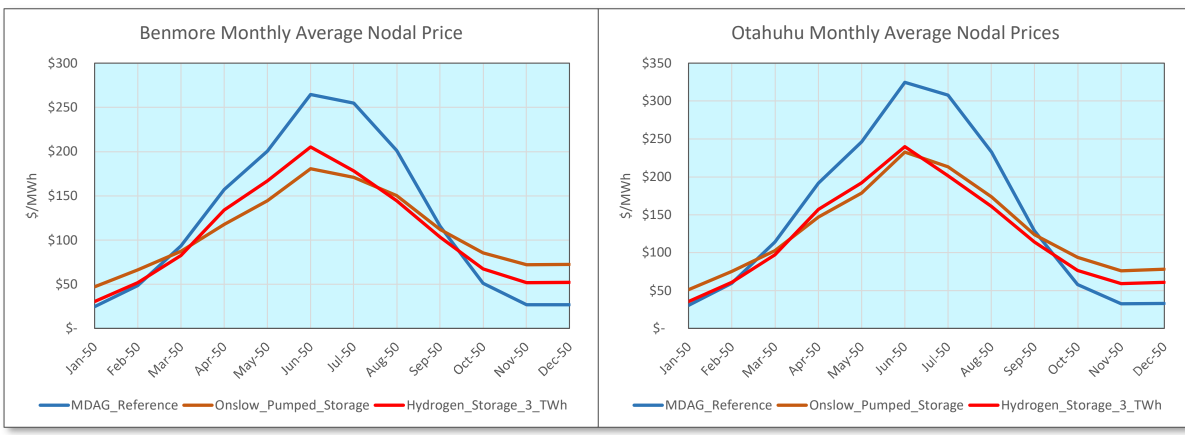


Table 4 shows the annual average prices including the percentage difference relative to the over-build scenario. Both the Onslow and hydrogen storage scenarios are significantly lower than the over-build scenario prices, and the hydrogen scenario is 5.9% lower at Otahuhu and 2.9% lower at Benmore.

Table 4 – Annual Average Spot Prices at Otahuhu and Benmore

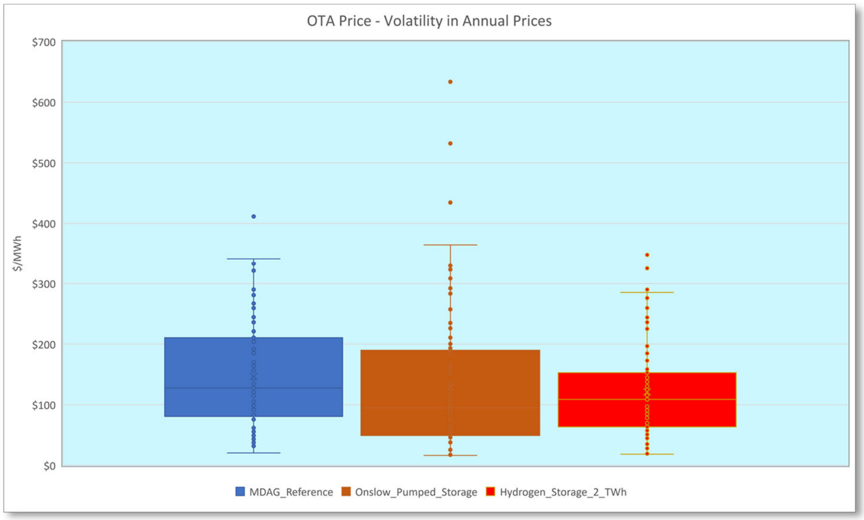
Annual Average Prices	MDAG_Reference	Onslow_Pumped_Storage	Hydrogen_Storage_2_TWh
Otahuhu	$147	$129	$121
Benmore	$122	$109	$106
Otahuhu	-	-12%	-17%
Benmore	-	-11%	-13%

[34] Although the impact on annual prices is driven by other factors including location.

4.3 Spot Price Volatility

The 'box and whisker plot'[35] in Figure 13 shows annual prices for all inflows at Otahuhu for all three scenarios. Within each box is the standard deviation for each scenario, calculated in the usual way, and these show that the Onslow scenario is the most volatile, followed by the over-build scenario, and the hydrogen scenario is the least volatile.

Figure 13 – Otahuhu Average Annual Prices for All Inflows



The over-build scenario has one fifth the storage of the 2,000 GWh storage scenario, and 100 MW less peaking capacity, so is less able to meet peak demand.

The Onslow scenario has the same generating capacity as the hydrogen scenarios, but even with the HVDC link upgraded, there are still occasions when the link hits its limit. Another factor here is that losses on the HVDC link are substantial, and reduce the Onslow's contribution to meeting peak demand in the North Is.

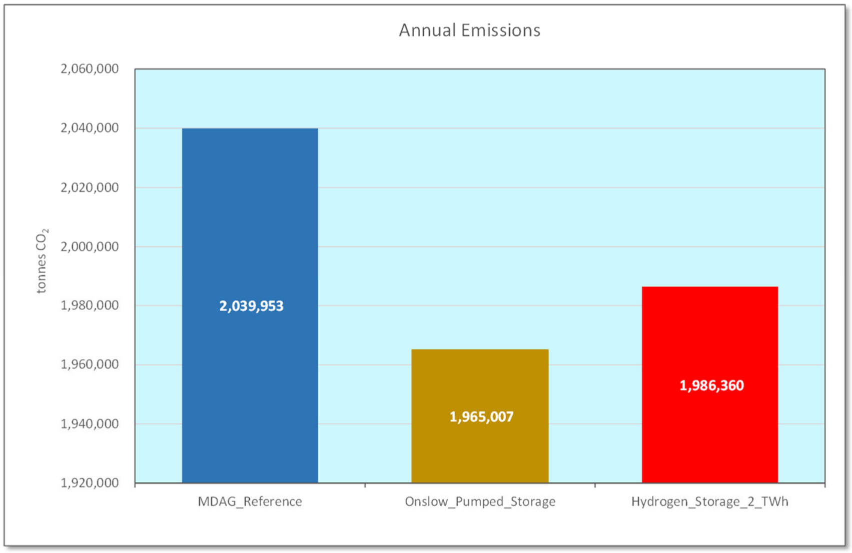
4.4 Emissions

All scenarios modelled are 100%RE, so the differences in emissions are due to the amount of geothermal generation that is built in each scenario, hence the over-build scenario has the highest emissions due to having more geothermal than the Onslow and hydrogen scenarios.[36]

Figure 14 below shows annual average emissions for all three scenarios[37], with over-build scenario the highest and Onslow the lowest. Relative to the Onslow scenario, emissions are 1.1% higher in the hydrogen storage scenario and 3.8% higher in the over-build scenario.

[35] The dots are the individual inflow scenario values. The upper and lower limits of the box are at the upper and lower quartile values, respectively. The horizontal bars show the boundaries of the 'inliers' according to Excel's somewhat arbitrary definition. Values above or below the bars are considered outliers by Excel, although in fact they are not outliers in the study, since the distribution of electricity prices tends to have a very "long tail".
[36] It is assumed that some cogeneration still operates, but that the associated emissions are the same in all scenarios.
[37] To put these figures into context, emissions in the year ending September 2021 are estimated to be 5.6 million tonnes.

Figure 14 – Annual Average Emissions



4.5 Spill

All scenarios have storage over and above the storage in the existing hydro lakes, but the over-build scenario has the least storage, and relies on the existing hydro lakes being held higher in summer to have sufficient storage going into winter, which results in large amounts of spill relative to the other scenarios and to what would be considered acceptable[38] today.

Figure 15 shows the spill from all types of generation for all three scenarios, with hydrogen storage the lowest at 1.8 TWh[39], and over-build scenario the highest at 6.5 TWh, which is 149% higher than the Onslow scenario and 257% higher than the hydrogen scenario.

In the over-build scenario, spill is higher for wind and solar as well as for hydro, which is a reflection of the higher level of over-build of renewable generation required in this scenario, along with holding the lakes higher. A core assumption of the over-build scenario, for that matter, is that investors in new generation will be prepared to take the risk of building new generation even when the generation produced from new projects could vary significantly from its theoretical values month-by-month and year-by-year.

[38] There is no formal definition of what is acceptable, but spill is only expected when floods put excess water into one or more hydro lakes, and not in the normal course of events.
[39] 1.7 TWh of this total is hydro spill. Between 2017 and 2021 inclusive, the average hydro spill was 1.1 TWh, although there were relatively dry years compared with many years in the historical record.

Figure 15 – Average Annual Spill from All Generation Types

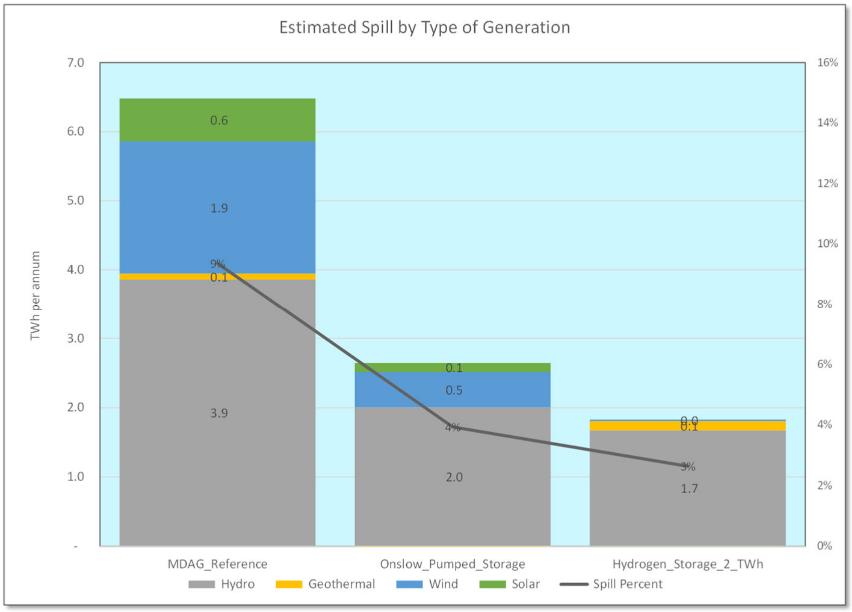
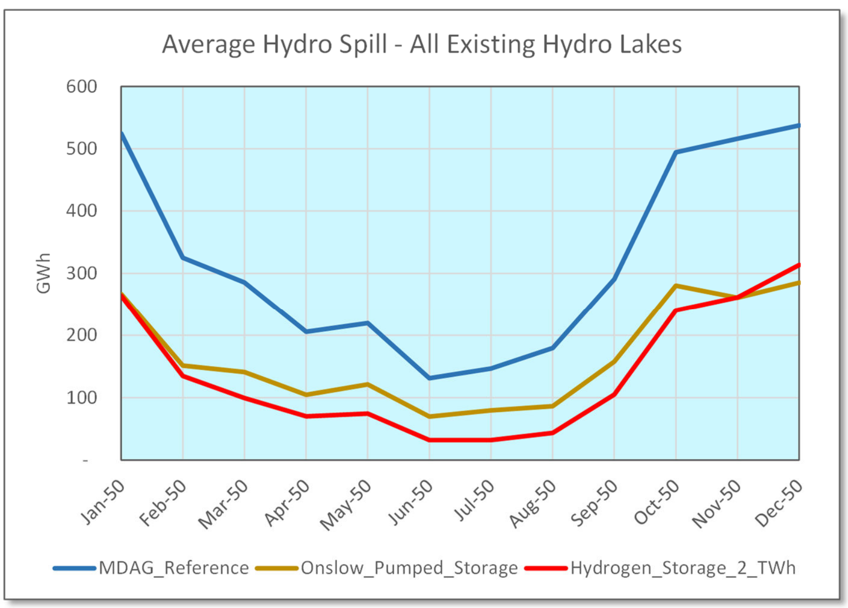


Figure 16 shows the seasonal average profile for spill from the hydro lakes (all of which are currently existing lakes), and the over-build scenario stands out as having higher spill in all months. Onslow is higher in the months of higher demand, where it is more likely to be generating than pumping, a reflection of its location in the South Is and the potential for the HVDC link to reach its maximum capacity.

Figure 16 – Monthly Average Hydro Spill



The hydrogen scenario has more spill from geothermal plant than the Onslow scenario, and similar to the over-build scenario, because geothermal generation is all in the North Is where most of the new renewable generation is built in these two scenarios. There are times of surplus renewable generation and very low prices, during which geothermal, solar and wind generation might all be competing to generate. In the real market there is a mechanism known as the Must-run Dispatch Auction (MRDA) which runs overnight and allows generators to bid for the right to offer into the market at zero dollars, which more-or-less guarantees dispatch, with geothermal generators more likely to bid than solar or wind generators due to constraints on the operation of the geothermal wells that supply these stations.

The MRDA is not modelled in any of the scenarios, so the amount of geothermal spill in the scenarios may be overestimated, but this is not significant in terms of the objectives of this study or the conclusions.

4.6 SLR

The amount of SLR in the market today is tiny. Since the scarcity pricing rules were introduced into the code in 2012, only one instance has occurred, the two-hour outage on 9th August 2021[40]. More events have occurred in which forced outages have occurred, but not due to insufficient generation being offered: these were all due to plant failures, e.g. failure of one pole of the HVDC link, or unplanned tripping of a large generator.

The modelling only captures events where there is a shortage of generation, so we should expect that modelling of today's market would show very little SLR. Figure 17 includes SLR data from an additional scenario labelled 'BC_2023' which is data taken from Energy Link's latest Price Path Base Case[41]. This scenario starts in 2023 and runs to 2048, but the 2023 data below shows the amount of SLR forecast to occur, over 91 inflow scenarios, in today's market. with an average of 1,027 MWh of SLR per annum, equivalent to losing supply to 500 MW of demand for an average of 2 hours per year.

All of the 2050 scenarios, however, have significantly higher SLR than today's market is expected to have, with the over-build scenario averaging 12,414 MWh per annum, Onslow 11,864 MWh per annum, and hydrogen storage 4,734 MWh per annum.

Figure 17 – Annual SLR for All Inflows

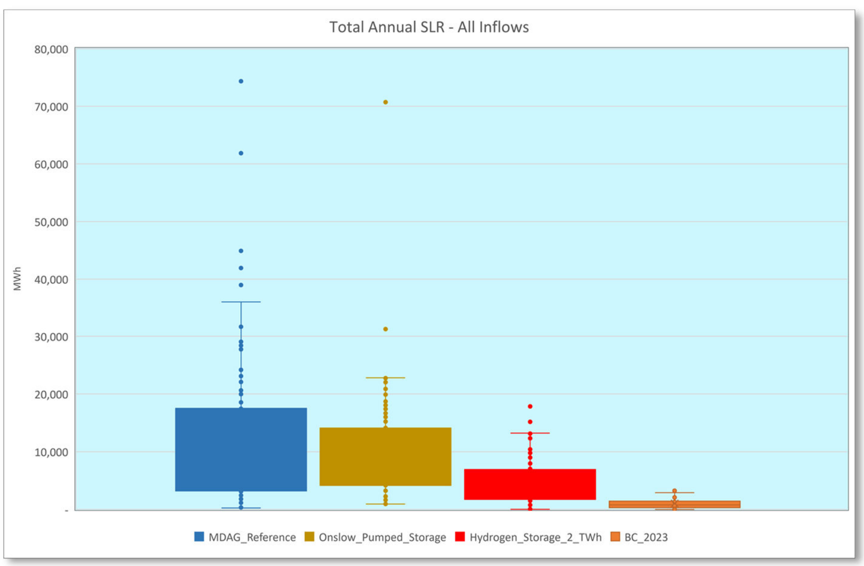


Figure 18 shows monthly SLR averaged across all inflows, with the over-build scenario highest in most months except in spring, during which Onslow would normally expect to be charging. There are a number of Onslow scenarios, however, in which Onslow storage, and hydro storage in general, is low and in these scenarios there is insufficient capacity available to supply peak demand in the North Is. The Onslow storage chart in Figure 10 shows that Onslow is operates closer to zero (when at the margins) than it does to

40 This was a scarcity pricing situation which, by definition, means there was not enough generation offered to meet demand, and there were forced outages in parts of the North Is for two hours. However, upon investigation, it transpired that forced outages would not have occurred, had Transpower's outage management system worked correctly.
41 Energy Link produces a quarterly Price Path which is based on scenarios for the future evolution of the electricity market.

full, so there is potential to move Onslow storage up on average, thus reducing the number of events in which SLR might occur.

The hydrogen storage scenario has the lowest SLR across the year because it is in the North Is, where the largest peaks in demand are, because it has five times more storage, and because it has 1,000 MW of peaking capacity compared to the over-build scenario with 900 MW.

Figure 18 – Monthly Average SLR

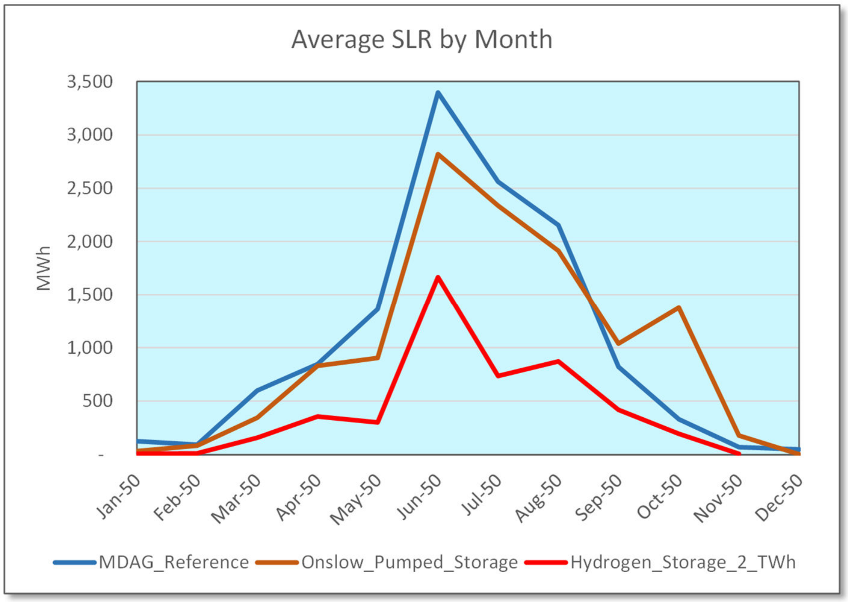


Figure 17 shows a stark difference between today's expectation for SLR and the results obtained for 2050 in all three scenarios. Greater DSR and SLR tend to feature in 100%RE scenarios modelled for New Zealand, which suggests an acceptance, tacit or otherwise, that either more SLR will occur in future with 100%RE, or that there will be sufficient DSR available to cope with all shortage and scarcity situations.

This leads to the question: will consumers, and elected representatives on their behalf, accept this? Or would they prefer a market that delivers secure supply without a requirement for more participation in the electricity market?

Answering this question is not part of this study, but as a general comment, any solution that is cost-effective and that requires less participation will likely be viewed favourably by consumers. There is likely to be opportunity to optimise the hydrogen storage scenarios to reduce SLR, discussed briefly in section 7.

4.7 Net Revenue

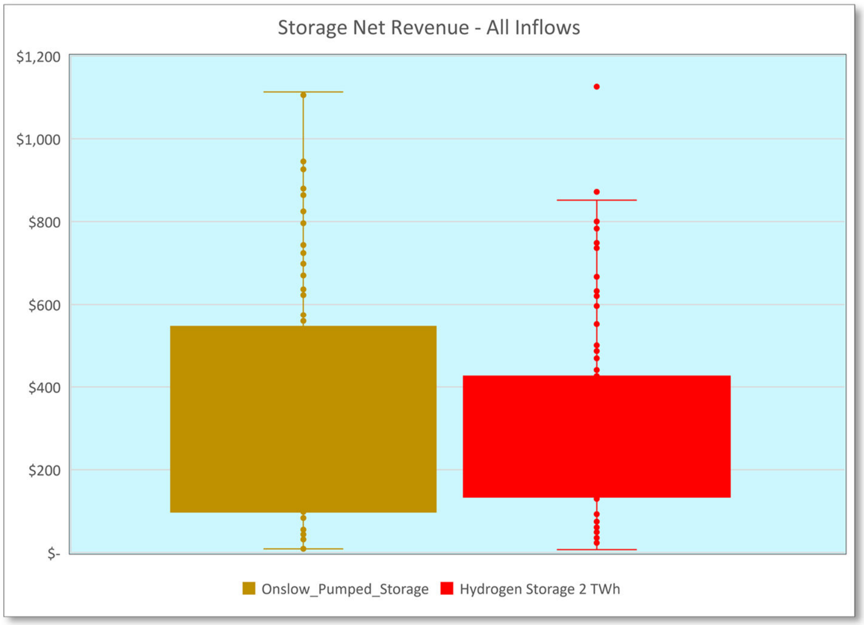
As far we are aware, storage in the 400 GWh of gas storage in the over-build scenario was not charged using electricity from the grid, so net revenue was not calculated in the same way as it was for the Onslow and hydrogen scenarios. There is a basic calculation in section 5 where we consider the costs of each scenario.

Table 5 shows the annual average revenue for the other two scenarios. Net revenue is the difference between the spot revenue earned by generating using stored water of hydrogen, and the cost of spot electricity incurred when water is pumped into Onslow or hydrogen is produced by electrolysis. There is substantial variation across the inflow scenarios, as shown in Figure 19 below, but there are no scenarios in which net revenue falls below zero.

Table 5 – Annual Average Net Revenue

Scenario	Average Net Revenue ($million)
Onslow PHES	$332
Hydrogen Storage 2 TWh	$318

Figure 19 – Storage Net Revenue for All Inflows



Even though Onslow storage is 2.5 times larger than the hydrogen storage facility, its revenue is about the same. The hydrogen storage scenario has some advantages over Onslow due to its location in the North Is.

Figure 20 shows a number of data series for the hydrogen scenario, averaged over all inflows and by time of day across the year, including North Is peak demand in each hour, with and without the electrolysers, the average HVDC flow by hour, the maximum HVDC flow in each hour, and the number of times DSR and SLR are dispatched in each hour of the day.

Figure 20 – Hydrogen Storage Scenario North Is Demand, HVDC Flows, DSR and SLR by Time of Day

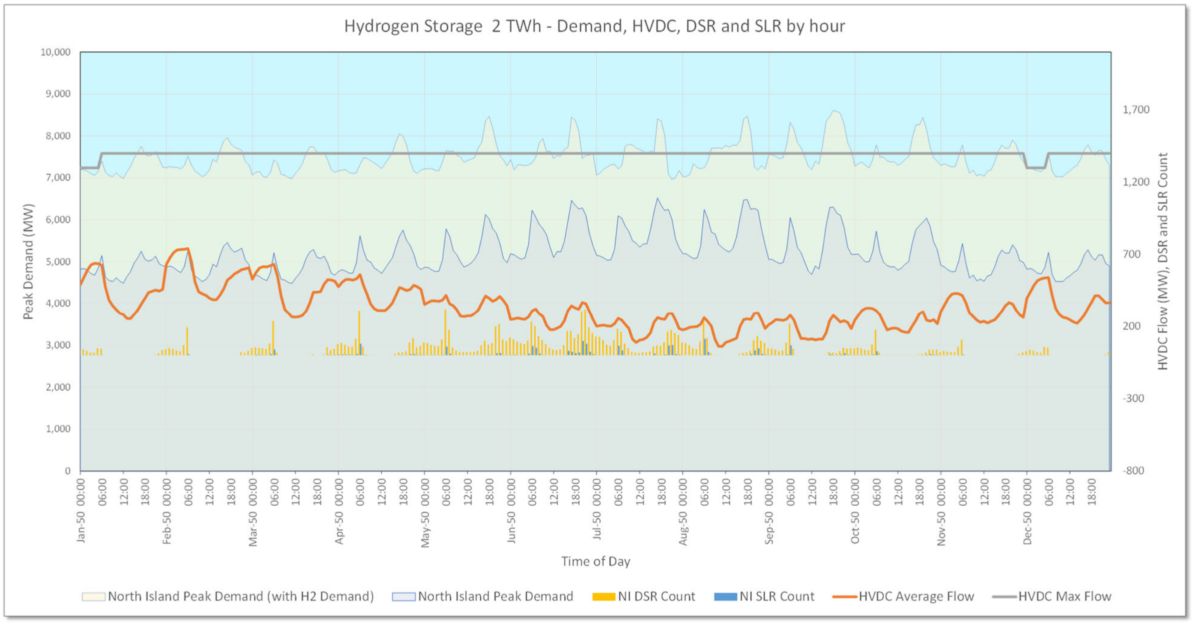


Figure 21 shows the same data for the Onslow scenario.

Figure 21 – Onslow Scenario North Is Demand, HVDC Flows, DSR and SLR by Time of Day

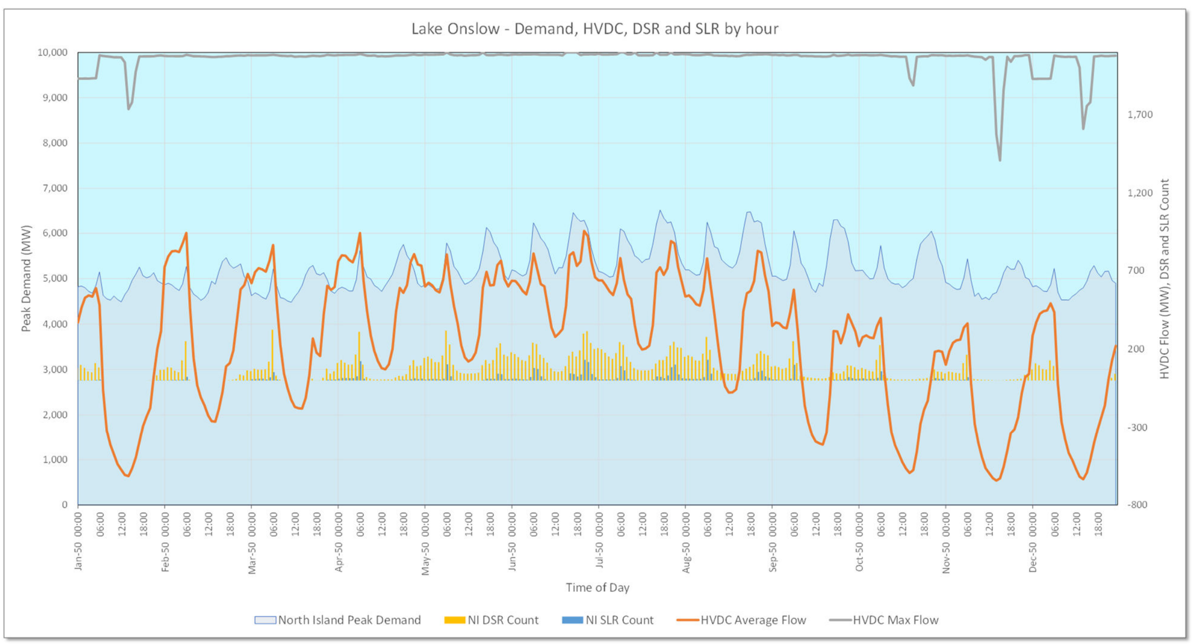
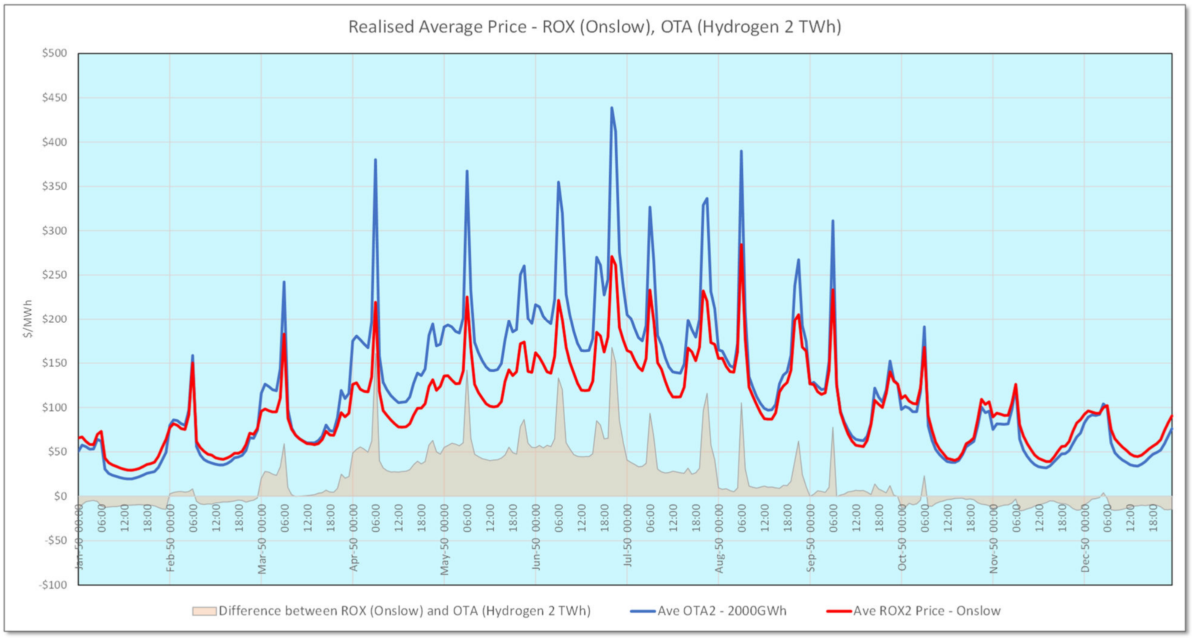


Figure 20 and Figure 21 illustrate key differences between the two scenarios, and similarities. The HVDC flows in the Onslow scenario are greater than in the hydrogen scenario, and show much greater swings during the day, and between seasons. Onslow needs to charge during the warmer months so that it can generate during the cooler months. But its higher round-trip efficiency (relative to hydrogen storage) also means that it can take greater advantage of lower prices within each day, by switching between generation and pumping as prices change; this results in larger swings within the day for Onslow.

Figure 22 below shows the average price achieved by each scenario, at Roxburgh (ROX) for Onslow (taken from the Onslow scenario) and Otahuhu (OTA) for hydrogen storage (taken from the hydrogen scenario), and the difference between the two. The price at Otahuhu is significantly higher than the price at Roxburgh during the months and times of the day when storage is discharged, and not much different when storage is charged, which boosts net revenue for hydrogen storage despite it being smaller than Onslow.

Figure 22 – Price Differences Between Scenarios



The charts also show the impact of solar generation on prices, with prices at night in the summer months, in particular, higher than prices during the middle of the day when solar output is maximum, i.e. the daily demand and price profile changes significantly from what it is now, where night time prices are lower than day time prices on average. Corresponding to this, the frequency of DSR and SLR events changes in line with the demand profile.

4.8 HVDC Outage Contingency

As already noted, consumers dislike interruptions to their supply, and as a result the amount of SLR is a key indicator of whether the market is functioning well, or not. The modelling focused on scenarios in which all plant and equipment functioned normally, but in reality there are often events when this is not the case, including planned and unplanned outages of key generating plant or key transmission lines.

The HVDC link is particularly key in this respect, due to it being the only transmission link between the two islands. Luckily, it has two poles and could have three poles if Onslow goes ahead, so there is built-in redundancy. However, the loss of a pole does limit the amount of transfer available between the islands.

An example is the outage of one pole on the HVDC link mentioned in section 3.2.3, in which one pole was out of service for the best part of three months in Q1 of 2020.

It is quite possible that an outage of this nature could produce quite different outcomes in the scenarios modelled for this study, so a similar scenario was modelled for this study; the loss of one pole of the HVDC link (700 MW) from 1st June to mid-July. This period was chosen instead of Q1, because it would put more stress on the electricity system, and hence is more likely to highlight differences between the scenarios. It is unlikely that a planned outage would be scheduled in winter, so this is more likely to arise from an unforeseen event such as a natural disaster.

Figure 23 shows the annual SLR for all inflows with and without the HVDC outage, with the former shown using cross-hatching. SLR rises in all cases, as one would expect, increasing by 46% for the over-build scenario, 111% for the Onslow scenario and 59% for the hydrogen storage scenario. The hydrogen storage scenario, with its additional peaking capacity and energy storage in the North Is, continues to deliver less SLR than the other two scenarios.

Figure 23 – Average Annual SLR

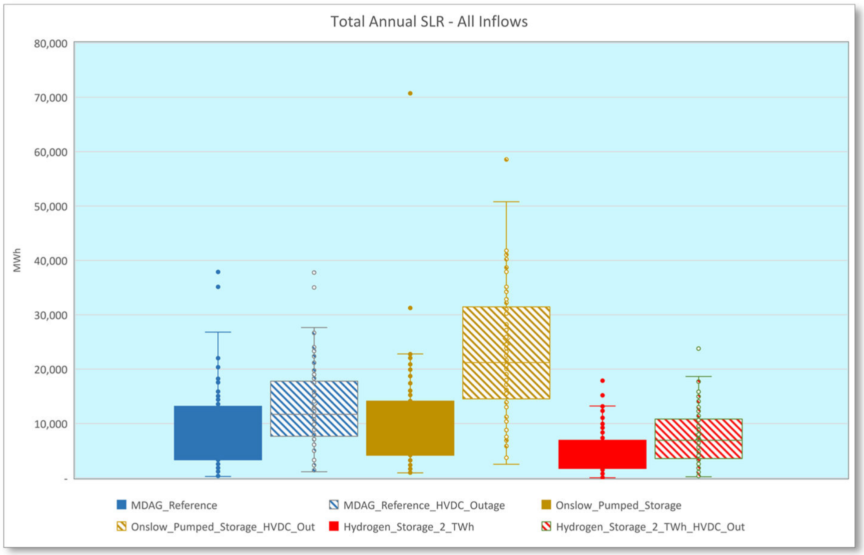
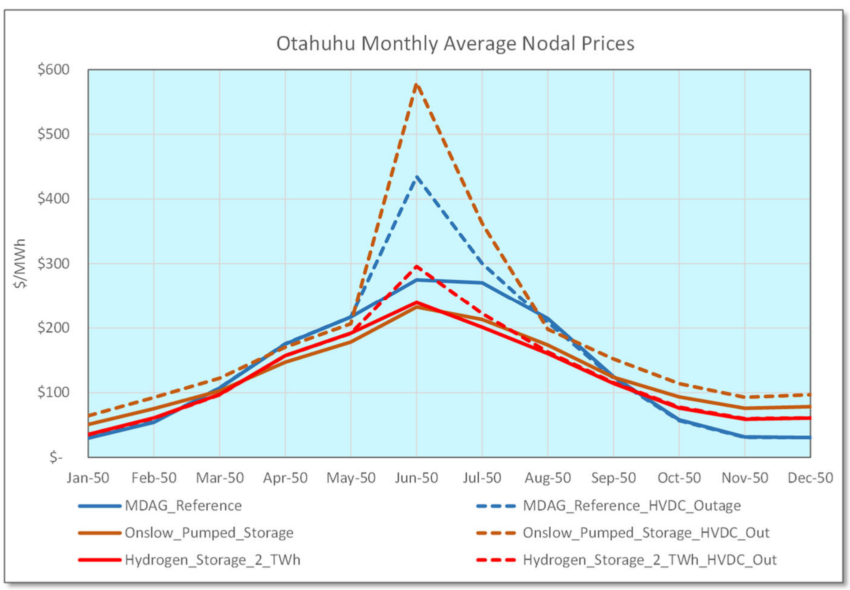


Figure 24 shows the change in monthly average price at Otahuhu, with Onslow seeing the greatest increase, followed by the over-build scenario, with the hydrogen storage scenario having the least price change.

Figure 24 – Otahuhu Monthly Average Prices



4.9 Losses

The pumping efficiency of Onslow is assumed to be 75%, which establishes the 25% bid-offer spread for its market operations at Roxburgh. But the HVDC flows shown in Figure 21 tend to be larger in both directions, indicating large swings in power flows up and down the country with Onslow in the South Is. This creates additional transmission losses of 90 GWh per annum on average across all inflows relative to the hydrogen storage scenario, which effectively reduces the round-trip efficiency of the Onslow scenario by approximately 4.5%, relative to hydrogen storage.

The additional losses do not require Onslow to increase its bid-offer spread at Roxburgh, because most of these losses are already accounted for in its water values, but it does increase the annual cost of electricity in this scenario because these additional losses must be served by additional generation.

5 Costs

The cost analysis considered fixed and variable costs for each scenario, in so far as these could be estimated with any accuracy. Capital costs are included as an annuity value and combined with operating costs to give an estimate of the annual total cost for each scenario, but only including assets directly relating to peaking capacity and storage.

The annuity value is based on the capital recovery factor and recovers the original capital cost over the life of the asset, and provides a commensurate return each year which matches the outstanding unpaid capital[42].

5.1 Onslow PHES and HVDC Upgrade

There is a particularly high degree of uncertainty around on the construction cost of the Onslow PHES, which might also include an upgrade to the HVDC link. There is a credible, albeit wide range of values for this ranging from $3.2 billion to $10 billion[43], to which we add the construction cost of a new pole on the HVDC link to give an upper limit value.

Replacement of the Cook Strait cables is required sometime in the next decade, and this could take the HVDC link capacity to 1,400 MW with or without Onslow proceeding, so the cost of this is ignored because it could be common to all scenarios.

But the cost of adding a third pole, to take the capacity to 2,100 MW as modelled in the Onslow scenario, is unknown. We can make a very rough estimate of the order of cost by looking at recent grid upgrades, for example the North Is grid upgrade project (known as the NIGUP) which added new a double-circuit 400 kV-capable transmission line from Whakamaru to Auckland, a distance of around 230 km, for $894 million or $3.9 million per km.

A third pole could have one stretch of about 600 km from Roxburgh to somewhere in the Marlborough Sounds, then 200 km on the seafloor to Taranaki, with a final stretch of around 240 km to Huntly. This suggests the overland transmission cost would be of the order of $3.3 billion.

Transpower says the cost of replacing the Cook Strait cables with four new cables, and possibly a spare fifth cable, which are about 40 km long, could be between $150 and $300 million, or between $3.8 and $7.6 million per km. A new seafloor route would probably be configured with two cables, so might cost between $380 and $760 million.

These estimates do not, however, include the cost of the electronics, switching and housing required at each end of a new pole. The last upgrade of the HVDC link was commissioned in 2013 and was primarily about upgrades of electronics, controls and switching, and cost $672 million. Starting from scratch with a new pole would cost even more, $0.3 billion at a guess.

Adding these components together, we get the following estimate.

[42] The annuity is the equivalent of a table mortgage.
[43] *Leveraging our energy resources to reduce global emissions and increase our living standards*, Infrastructure Commission, June 2022.

Table 6 – HVDC New Pole Cost Estimate

Component	Cost Estimate ($billion)
Overland transmission lines	$3.3
Seafloor cables (middle value)	$0.6
Electronics, control, switching, housing	$0.3
Total	**$4.2**

Most of the estimate is based on the NIGUP which was completed in 2012, so inflation has likely increased this cost significantly since then, as with the last HVDC upgrade. Again this is a guess, but this could add another $0.8 billion to the overall cost (20%), taking our estimate to approximately $5 billion dollars all-up.

This brings the total estimate for the additional cost of Onslow PHES, including HVDC upgrade at the upper end, to between $3.2 billion and $15 billion.

Onslow's operating costs were taken as $9.8/MWh based on the expense notes in Meridian Energy's latest set of accounts, and assumed to be incurred on the total of Onslow's generation and pumping.

5.2 Over-build scenario

The cost estimates are based only on the 900 MW of green peakers, which are assumed to cost $1.2 million per MW of installed capacity, on the assumption that they would be built new at some point[44].

It is not clear how the 400 GWh of storage is provided, and what capital and operating costs would be associated with this storage, so these were ignored for the purposes of these rough estimates.

5.3 Hydrogen Storage

The construction and operating costs of hydrogen storage were provided by Firstgas Group at $54 per MWh of hydrogen storage capacity for construction and $0.1 per MWh of hydrogen stored. The construction costs include any 'gas buffering' required, i.e. gas injected into the storage facility but not available for extraction.

Electrolyser operating costs of 5% of capital cost, scaled by capacity factor, were taken from a report by Concept Consulting dated 2019[45].

Firstgas Group also provided an estimate of $615 construction cost per kW of electrolyser capacity in 2050[46].

As for the over-build scenario, $1.2 million per MW was used as the gas turbine construction cost.

5.4 Common Costs

It is assumed that all scenarios would incur similar costs in respect of gas transmission. In the case of the Onslow scenario, even though no gas is used for electricity generation, there may still be gas available for consumption in some form, outside of the electricity market.

Transmission charges were based on an estimate of Meridian Energy's charges for FY24, under the new TPM which applies from April 2023; the value estimated was $4.5/MWh.

[44] Use of existing peaking plant is also an option, but this plant will be 30 years old or more by 2050 so there is significant uncertainty about this strategy.
[45] Hydrogen in New Zealand Report 2 – Analysis, Concept Consulting, version 4, 29-Jan-2019.
[46] Concept Consulting's estimate in future, stated in the above report, was $700 per kW.

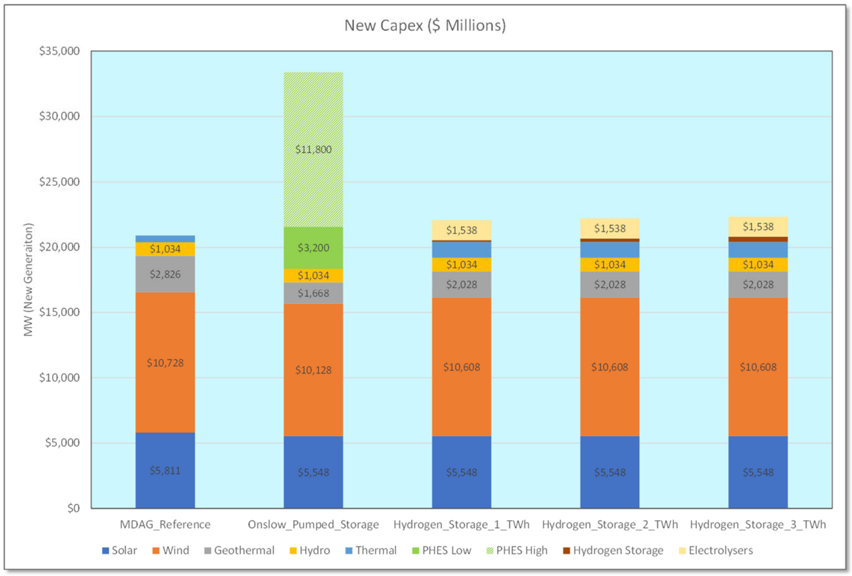
5.5 Annual Cost Comparison

The total new capex is shown below in Figure 25 below. There is a very wide range of costs estimated for the Onslow scenario, which is a function of the nature of large-scale infrastructure projects which are often subject to cost increases and delays.

By comparison, the uncertainty in the hydrogen storage scenario is largely a function of the 'hydrogen economy' being in its infancy, with many factors that could impact on the costs favourably or unfavourably over the coming decades.

The over-build scenario figure does not include the 400 GWh of gas storage because it is not clear how or where the storage would be provided.

Figure 25 – All-up Capex for New Generation, PHES and Hydrogen Scenarios



Transpower's post-tax WACC is currently 4.57% to which we must add tax and then subtract the impact of inflation, assumed to be 2% per annum, to get approximately 6.3% real pre-tax. This may or not be the WACC in any particular case, but it is likely to be relevant to large infrastructure projects[47], and use of a common WACC facilitates a better comparison.

The Low scenario for Onslow was not modelled, but included to indicate where costs might land for this configuration.

All results for net revenue are the average over 91 inflow sequences for 2050. In some years some options would recover more from the spot market, and less in other years.

In Table 7 below, the total annual cost is calculated, and then average annual net revenue is subtracted to give the total sum not recovered from the spot market over an average year. A positive value means the option would require additional revenue over and above what it recovers from the spot market, and a negative value means it recovers more from the spot market than required to cover all fixed and variable costs, along with it target RoI.

Over-build scenario operating costs do not include fuel costs of $45/GJ, which are instead included in the net revenue calculation for this scenario, along with the generation revenue from the spot market.

[47] Commercial developers may have higher WACCs due to different risk profiles and commercial drivers.

In the Onslow scenario, the storage capex includes the generator-pump units. The Onslow economic life is an average across lake and dam-related assets, with lifetimes of 80 – 100 years, generating units and transmission assets with lifetimes of 50 to 80 years, and the electronic and other control assets associated with the addition of a third pole on the HVDC link, with lifetimes of 20 – 30 years[48].

Table 7 – Annual Cost Estimates

		Over-build	Onslow Pumped Storage		H_2 Storage
			High Capex	Low Capex	2 TWh
Storage capacity	GWh	400	5,000	5,000	2,000
HVDC additional pole	MW		700	0	0
Storage capex	$Billion	$0.00	$10.00	$3.20	$0.27
Generator capex		$1.08			$1.20
Electrolyser capex	$Billion				$1.54
HVDC Capex	$Billion		$5.00		
Total Capex	**$Billion**	**$1.08**	**$15.00**	**$3.20**	**$3.01**
Pre-tax real WACC		6.30%	6.30%	6.30%	6.30%
Economic life	Years	25	50	50	20
Annual capital recovery	$Billion	$0.09	$0.99	$0.21	$0.27
Annual opex incl. TPM	$Billion	$0.20	$0.06	$0.06	$0.04
Total annual cost	**$Billion**	**$0.29**	**$1.06**	**$0.28**	**$0.31**

Table 7 shows that the over-build scenario, Onslow with capex at the lower end of the range, and hydrogen storage have comparable annual costs[49].

Table 8 shows the annual net revenue from Table 5 for Onslow and hydrogen storage, along with an estimate of the annual costs of the gas peaking generation in the over-build scenario. When this is subtracted from the total annual cost in Table 7, we obtain the annual costs that are not covered by the net revenue from spot market operations, i.e. from buying low and selling high.

Table 8 – Costs Not Recovered via the Spot Market

		Over-build	Onslow Pumped Storage		H_2 Storage
			High Capex	Low Capex	2 TWh
Annual net revenue	$Billion	$0.22	$0.33	$0.33	$0.32
Annual costs not covered by spot market net revenue	**$Billion**	**$0.07**	**$0.72**	**-$0.06**	**-$0.01**

The table shows that Onslow would recover all costs from the spot market if its capital cost is at the low end of the range (closer to $3.2 billion), but only just, and an increase in capital cost of as little as $1 billion would take it into the red.

Without counting the costs of gas storage, the over-build scenario does not recover the costs of its peaking generators from the spot market, with fuel at $45/GJ; the break-even point would be around $37/GJ.

The hydrogen 2 TWh storage scenario just recovers its costs from spot market net revenues.

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48 A longer life of 80 years, for example, does not change the conclusions.
49 Although, as noted elsewhere, the MDAG reference case does not include fuel storage costs.

6 Ownership

An assumption implicit in the modelling was that the hydrogen storage, peaking generators and electrolysers were all under common ownership, so the question of how separate ownership might impact on the operating strategy did not arise.

In reality, however, common ownership would not be required to make large-scale hydrogen storage work.

For example, suppose there are separate owners for the storage facility, for the gas pipelines, for the generators (all generators owned by the same entity) and the electrolysers (all electrolysers owned by the same entity). Then the electrolyser owner would contract to sell hydrogen to the generators and other gas users. It would produce green hydrogen and contract with the gas pipeline owner to transport the gas to the storage facility.

The generator would contract with the storage facility owner to store the gas, and contract with the gas pipeline owner to transport the gas from the storage facility to its generating plant.

If anything, separate ownership could produce better outcomes than common ownership, as this would promote competition and innovation in storage, green hydrogen production and generation, and also facilitate incremental development of green hydrogen-based production and generation.

7 Hydrogen Optimisation

The modelled hydrogen scenarios were set up with generation and electrolysers to match the charge and discharge rates of the Onslow scenario, without any attempt to optimise the configuration, apart from selecting 2,000 GWh as being a likely storage volume.

The electrolysers frequently operate at their full capacity of 2,500 MW, but only achieve an average capacity factor of between 18.6% and 20.3% in the three scenarios initially modelled, though even at these low values, the estimates suggest that their annual costs would be recovered from net revenues. But it is obvious that further investigation might allow the capacity to be reduced without compromising the overall hydrogen solution.

Alternatively, if there are significant other uses of hydrogen gas in 2050, the spare capacity could be applied to supplying gas in real-time rather than into storage for electricity generation.

The second obvious strategy to investigate would be to increase the peaking capacity to further reduce the amount of SLR in the hydrogen scenarios.

8 Conclusions

The key question to be answered was: how does an electricity system utilising large-scale hydrogen storage compare with other key alternatives in delivering the needs envisaged in 2050 across all three sides of the ‘energy trilemma’. The results of this study are to inform where further investigation and development should be focussed.

An ideal market configuration for serving the market with 100%RE in 2050 would feature affordable electricity, minimal impact on the environment and secure and reliable electricity supply. At this point in time, we don’t know with any certainty that it is feasible to store hydrogen in depleted gas fields on and offshore Taranaki, and nor do we have any certainty over the various costs of creating and operating this storage. The future costs of constructing and operating grid-scale electrolysers in 2050 are also uncertain. So, it would be premature to jump to any firm conclusions about the hydrogen storage scenarios.

However, the hydrogen storage scenarios do have a basic attraction in the sense that they would effectively replace the existing thermal fleet and natural gas storage, in the North Is, and potentially reduce the need for large-scale demand-response by consumers.

The modelling suggests that hydrogen storage would perform well over a range of indicators, including spot prices, spot price volatility, emissions, spill, SLR, managing large contingencies such as the loss of one pole of the HVDC link. The cost analysis also suggests the hydrogen storage scenario could be competitive in terms of annual all-up costs.

A hydrogen storage solution also offers the potential for it to be:

- scaled up in stages;
- optimised across storage, electrolyser capacity and generation;
- scaled to produce gas for uses other than electricity.

There is high uncertainty over the cost of the Onslow scenario, and developing Onslow would have substantial and obvious environmental impacts which the over-build scenario and hydrogen storage would not.

The over-build scenario has the lowest total cost of new generation and storage, although there is uncertainty over the costs associated with the 400 GWh of fuel storage, which is not included in the estimates in this study. Since the over-build scenario already has gas storage on a relatively small scale, the hydrogen storage scenarios can be thought of as a ‘hydrogen-fuelled over-build scenario with more storage but without the over-build’.

Taken overall then, large-scale hydrogen storage has a number of attractive features, and may also be cost-effective for electricity-related storage, relative to the alternatives modelled. There is already work underway in New Zealand to investigate the feasibility of large-scale storage of hydrogen in depleted natural gas fields, and this study confirms that a hydrogen storage strategy warrants further investigation.