Flexible geothermal application within the New Zealand electricity market

Andrew Marsh[1], Mohammad Aljubran[2], Iraklis Konstantopoulos[1] and Mana Newton[3]

[1]Upflow, 3 Winston Street, Acacia Bay, Taupo, 3330, NZ

[2] Stanford University, 367 Panama Street, Stanford, CA 94305, USA

[3] Tauhara North No.2 Trust, 283 Vaughan Road, Owhata, Rotorua, 3010, NZ

andrew.marsh@upflow.nz

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ABSTRACT

Geothermal power production plays an important role as baseload in the New Zealand electricity market, supplying 18% of the total electricity production in the last calendar year. The proportion of gas peaker supply has decreased from 15% to 10%, while wind and solar have grown from 5% to 7% over the last five years and are set to grow rapidly over the coming decade.

The change in energy mix and a projected growth in demand pose significant challenges for system management. New Zealand is considering options to cover the risks posed by increasing variability of supply plus a shortfall of hydro storage during drier-than-average years. This is called the New Zealand Battery Project and preliminary studies have identified biomass, flexible geothermal energy, and hydrogen as alternatives to a large-scale pumped hydro scheme. Collectively, these alternatives have the most potential to store enough energy to help solve the "dry-year problem".

In geothermal systems with under utilised generating capacity due to resource depletion, it may be possible to redistribute electricity production across the year to when it is most needed. This lets the resource recharge when electricity demand is low, thus facilitating boosted output for limited durations when demand is high. However, this does not apply in New Zealand where geothermal resources are rarely the limiting factor and the underlying economics bias towards full utilisation of the capital-intensive plants and wells. Consequently, all geothermal in New Zealand has so far run as baseload.

This study models, using recent electricity market price data as a baseline, what conditions need to be present and to what extent it may be advantageous to vary output from geothermal power plants in the New Zealand context. Additionally, we consider the role of batteries, thermal energy storage and co-production of fuels, chemicals, and other value-adding products at geothermal sites: can they support flexible geothermal by providing an alternative utilisation path for renewable electricity while market prices are low?

1. INTRODUCTION

Geothermal energy has been a key contributor to New Zealand's transition to a low-carbon electricity system. As the country has reduced reliance on coal and gas, geothermal plants have provided reliable baseload power to help meet demand. However, geothermal also faces some challenges that require careful management and innovation. Geothermal is competing with other renewable energy sources such as wind and solar, which have become more prominent in plans for new generation in recent years due to their falling costs, as seen in Figure 1.

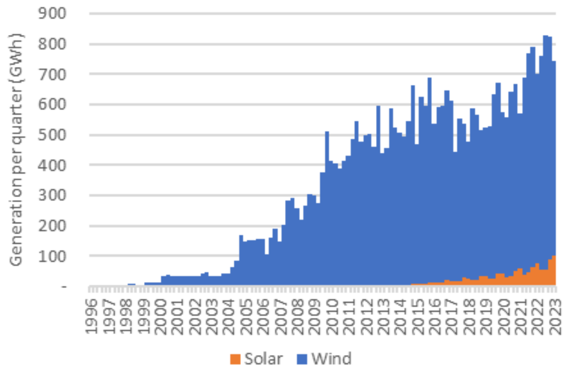

Figure 1: Increase in the generation per quarter from wind and solar sources in New Zealand from 1996 to today (MBIE, 2023). The increasing trend is expected to continue.

The growth of wind and solar power in New Zealand has been supported by the availability of hydro, geothermal and thermal (gas) power, which can provide capacity firming for these variable sources. Capacity firming means that an electricity generating entity (generator) can balance the fluctuations of wind and solar power, which depend on weather conditions, by adjusting the output of other sources of power that can be controlled more easily on demand. This way, the generator can ensure a stable supply of electricity that matches the demand, avoid an over- or under-supply condition in the market, reduce price volatility and achieve stable revenues.

For this reason, wind and solar projects usually include a financial adjustment in their metrics to account for the generation not necessarily arriving when it is needed. With more wind and solar due to be added to the grid, the accumulation of generation at certain times of the day and year leads to this generation being valued below the average power price. This can be exacerbated by "location factors" that account for timing of wind speeds, sunshine hours and peak transmission constraints that limit the value of the power generated. As more wind and solar are added to the grid and more thermal generation is retired, New Zealand faces a trade-off between using its hydro capacity to balance the intermittent renewables and to store enough water for dry years. Despite the lower build cost of wind, these market mechanisms have resulted in both wind and geothermal projects being developed on competitive terms in recent years.

To allow further wind and solar developments and continue the push towards a 100% renewable electricity supply, the central government has commissioned the New Zealand Battery Project. This is a study led by the Ministry of Business, Innovation and Employment (MBIE) to explore the potential of a large-scale pumped hydro scheme (or alternatives) for the national grid. The project aims to assess the technical, economic and regulatory aspects of 'battery' deployment and operation, as well as the benefits and challenges for the electricity system and the market. Preliminary studies have identified alternatives to pumped hydro to be biomass, flexible geothermal energy, and hydrogen. Since the project is targeting between 3-5TWh of storage (MBIE, 2023) on a seasonal timescale, chemical batteries are not considered feasible.

Flexible geothermal energy is a concept that allows the operator to control (dispatch) the amount of electricity produced from geothermal sources depending on the demand and the market conditions. Compared to baseload geothermal plants that run at a constant rate, flexible geothermal plants should be able to significantly adjust their output up or down without wasting the heat resource or they should have a way to 'store' the energy for release later when it will be valued more.

The geothermal industry in New Zealand has not been particularly incentivised to configure plants for flexibility, to date. The economics have favoured continuous supply at full generating capacity since generally the resources can support more electricity than the power plants can produce. Operators have been cautious not to overbuild and the consenting and permitting process is also conservative. There are options to achieve flexibility by making modifications to the existing facilities and processes. However, in the current state, flexibility would mean reducing electricity output to the grid with little possibility to the increase output later and so would reduce the utilisation of the generating asset.

If the 'storage' aspect could be enhanced by providing an alternative value stream for the electricity when not needed on the grid, then the power station can remain fully utilised while improving the overall value (and revenue) gained. This would provide a service to the grid by reducing geothermal output at times when there is plenty of wind, sun, or water. Alternative value streams could include production of a product (e-fuels, e-chemicals, horticulture, biofeedstocks), a store of energy (batteries, thermal storage, hydrogen) and market and financial instruments (avoided cost of transmission, locational hedges).

2. PROBLEM STATEMENT AND GOALS FOR THIS STUDY

The analysis presented in this paper sought to assess the current value of flexible geothermal using some illustrative examples. This demonstrates how flexibility could derive value in the context of the electricity spot market and how an alternative value stream co-located at a geothermal facility can support the business case for both geothermal generation and the co-located industry.

The analysis so far completed does not attempt to forecast how the value of flexibility will sustain or grow or disappear in the future since this involves considerably more assumptions. However, it is hoped that a demonstration of current value and a methodology can be the starting point for a forecast for those who wish to consider such ventures more deeply. This way, venturers can ascribe inputs they are comfortable with and then work with the uncertainties and risk levels as they see fit.

The study has focused on the economics for batteries and hydrogen. Hydrogen electrolysis is an electricity-intensive precursor to a large range of e-fuels or e-chemicals and so either directly or as a proxy can help explore a range of products without expanding the scope to study them all in detail. Difficulties in storing and transporting hydrogen mean that it is not necessarily the best end-product to produce at geothermal locations, so storage of methanol is also considered since it can illustrate the costs of product storage more reasonably.

Starting our analysis in 1996, when wholesale market data became available in New Zealand, we study:

- Trends in the volatility of electricity prices.
- Whether recent price volatility, if it continues, would justify a battery installation (e.g. lithium-ion)–this being the simplest way to solve an intra-day intermittency supply/demand gap. If the case for batteries becomes convincingly positive, then it is likely we will see battery adoption in a way where the future intra-day price volatility will be effectively capped and the value may shift to longer storage timeframes such as seasonal variability.
- The break-even sale price, or levelised cost of hydrogen (LCOH), for a constant hydrogen production scenario–this would require minimal storage when addressing the local market for hydrogen in heavy transport and industry, where demand is seasonally constant (MBIE, 2023).
- The LCOH for a flexible hydrogen production scenario–this lowers the average cost of the electricity input but requires product storage to buffer to a constant market demand.
- The mass (or volume) of hydrogen storage required to achieve a constant hydrogen supply and the implied costs of this storage, for:
    - Compressed hydrogen (700 bar)
    - Liquid hydrogen
    - Methanol
- The extra capital expenditure a flexible hydrogen production regime could afford if it sells hydrogen at the higher LCOH price calculated for constant hydrogen production–if product storage and any other investments are needed to make flexibility work then they need to cost less than this for a flexible production regime to improve upon a constant production regime.

3. METHODOLOGY

A model was built to simulate a flexible geothermal power plant's revenue when attached to either a battery, a constant hydrogen electrolysis plant, or a flexible hydrogen plant and then compared to the baseload geothermal business outcomes.

- A **battery** (based on the Tesla Megapack), situated between the geothermal power plant and the grid and under the direction and ownership of the geothermal operator, serves as a milestone case in this analysis. If a battery installation can turn a profit under current conditions, then this is the simplest form of enabling an operator to trade on volatility (arbitrage). There may be some reasons to locate at a geothermal site (such as it being a convenient grid entry point) but the battery would be largely independent of needing to be at a geothermal operation.

- **Constant hydrogen** production represents a production scheme not taking advantage of the variation in wholesale power prices but rather utilising an electrolyser 100% of the time.

- **Flexible hydrogen** production is a scheme where hydrogen production is increased and decreased according to the wholesale market electricity price in relation to a threshold (marginal) electricity price for producing hydrogen. Hydrogen is only produced when the hydrogen is worth more than the electricity used to make it.

- **Methanol** production is a chosen example of a post-cursor product of hydrogen that is much easier to store. This paper does not attempt to make a case for methanol specifically, rather, treats the hydrogen price as a proxy key input related to electrical demands for methanol production. Production of methanol and other e-fuels (such as SAF) and e-chemicals is beneficially co-located with geothermal since carbon (in the form of CO_2), heat and renewable electricity are readily available.

To evaluate these scenarios, the final pricing (P_{final}, NZ$/MWh) was extracted from the Electricity Authority website (EA, 2023) for the half-hourly periods from 1st October 1996 to 25th June 2023. The chosen node location on the national grid was Wairakei 220kV node, seen in Figure 2, as this receives the largest portion of geothermal generation load.

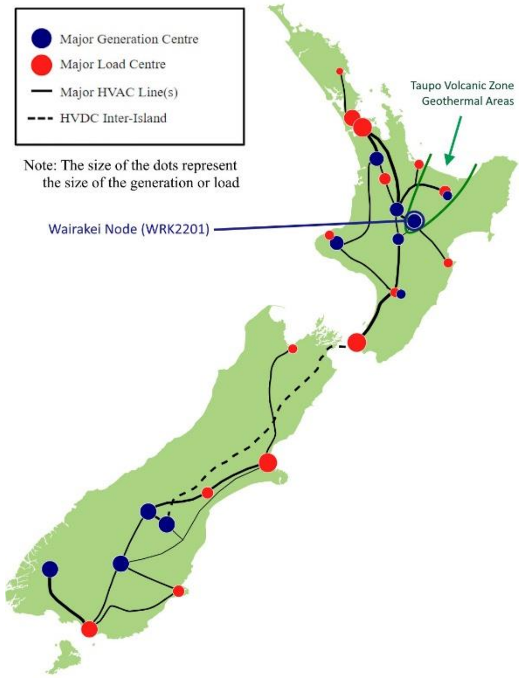

Figure 2: Location of Wairakei Node in New Zealand electricity system (Lcmortensen, 2023)

The data was broken up on a calendar year basis. This was used to determine the baseload revenue (R_{base}):

$$R_{base} = \sum_1^N P_{spot} \times \dot{P}_{base} \tag{1}$$

where P_{spot} is the half-hour period wholesale electricity spot price in NZ$/MWh, $\dot{P}_{base}$ is the geothermal baseload power station rating in MW, N is the total number of half-hour periods for the time period of interest (usually a calendar year).

Based on the half-hourly final pricing, logic was implemented to decide whether to charge or discharge the battery or produce hydrogen in the current period. Charging occurs when the battery is not full and the average price over the forward averaging period, $N_{forward}$, is higher than the current period. Discharging happens when the battery is not empty and the forward price over the forward averaging period is lower than the current period. Hydrogen production occurs when the electricity spot price is below a threshold, $P_{threshold}$. The threshold price for hydrogen production (to at least cover the cost for the electrical input) is set as the sale price, P_{H2} in NZ$, multiplied by the unit production rate, R_{H2} in kg/h/MW. The production of hydrogen in all scenarios works out to be 1594 tonnes per annum.

$$P_{threshold} = P_{H2} \times R_{H2} \tag{2}$$

When the battery is charging and discharging or hydrogen production is active the electrical generation to the grid, $\dot{P}_{grid}$ in MW, will vary according to the input parameters and the scenario.

$$\dot{P}_{grid} = \dot{P}_{base} - \dot{P}_{charge} + \dot{P}_{discharge} - \dot{P}_{H2} \tag{3}$$

where $\dot{P}_{charge}$ is the rate of battery charging in MW, $\dot{P}_{discharge}$ is discharge rate of the battery, which is the same as the charge rate minus a round-trip efficiency and $\dot{P}_{H2}$ is the electrical consumption for the hydrogen electrolyser.

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Revenue, $R_{scenario}$ in NZ$, can then be allocated for each half-hour period based on the spot price for electricity going to the grid and the set hydrogen sale price.

$$R_{scenario} = \left(P_{spot} \times \dot{P}_{grid} + P_{H2} \times R_{H2} \times \dot{P}_{H2}\right) \times \frac{1}{2} \qquad (4)$$

The revenue generated across the calendar year for the set of input assumptions is calculated and can be evaluated against the other input parameters to determine a project's net present value (NPV). NPV is adjusted to zero, by iteration, to determine break-even situation for the hydrogen sale price. A levelised cost of hydrogen (LCOH) was determined in this way. A simple two-parameter optimisation was completed for batteries using the forward spot price averaging period and the capacity-to-charge ratio.

LCOH was calculated for constant and flexible hydrogen production routines to determine the minimum sale prices while producing the same quantity of hydrogen across the calendar year. To achieve this, the installed electrolyser capacity for the flexible hydrogen scenario was increased and costed higher accordingly. A lower LCOH for a flexible hydrogen production scheme demonstrates an advantage for this production method due to a significantly reduced average electricity price that outweighs the impact of reduced utilisation of the up-front electrolyser capital costs [CAPEX].

An alternative way to represent this advantage is to determine the additional CAPEX supported if the hydrogen price was set at the LCOH for the constant hydrogen scenario. This may be used to buy storage to smooth out supply to the market, to approximate the constant production case if required, or to generally cater for or profit from this mode of operation.

The storage mass/volume of hydrogen or methanol required to buffer and achieve a constant supply rate to the market are also recorded. The sequence of these calculations are shown in Figure 3.

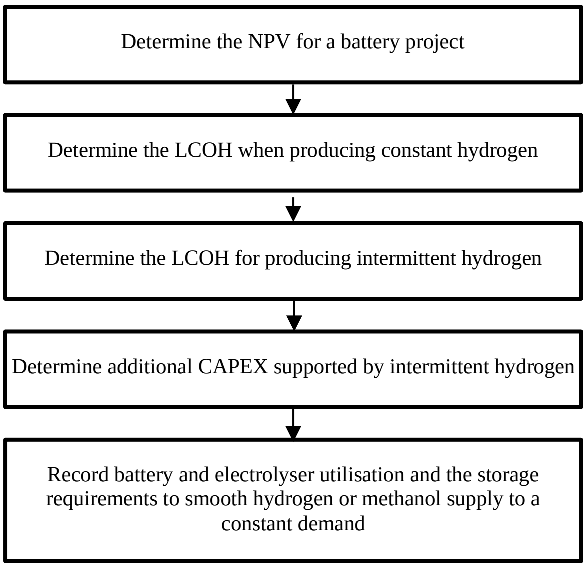

Figure 3: Calculation routine for each time period

4. INPUT PARAMETERS

The following were used as inputs for the analysis.

Table 1: Inputs to the analysis

Input	Value	Unit	Notes / Assumptions
Power Station Rating, $\dot{P}_{base}$	100	MW	
Forward Averaging Periods, $N_{forward}$	6	half-hours	(subjected to an optimisation routine)
Discount rate	7.0%		(for NPV calculations)
Capacity of Battery	40	MWh	
Battery capacity-to-charge ratio	2	MWh/MW	(Tesla Megapack 2:1 or 4:1)
Project Life for Batteries	15	years	(Tesla Megapack comes with a 15-year "no defect" and "energy retention" warranty)
Unit cost of Batteries	800	NZ$/kWh	(Tesla Megapack NZ$32M for 40MWh incl shipping and installation)
Battery Maintenance	2.5	NZ$/kWh	(Tesla Megapack estimated annual maintenance)
Round-trip efficiency	92%		(Tesla Megapack 2:1)
Electrolyser capacity, $\dot{P}_{H2}$	10	MW	
Production rate of H2, R_{H2}	18	kg/h/MWe	(Based on 55kWh/kg, 40kWh/kg theoretical minimum)
Project Life for Electrolyser	10	years	(estimated)
Unit cost of electrolyser	2.5	NZ$M/MWe	(estimated from prior quotations)

5. RESULTS

5.1 Electricity market prices and variability over time

Firstly, to illustrate how the market has evolved over time, Figure 4 plots average prices and the standard deviation of prices to illustrate the variability. Whereas retail price spikes are driven by various supply/demand dynamics, one common driver is occasions with low hydroelectricity supply coinciding with high demand. The variability is notably higher since 2018 due to a reduction in gas-fired generation and increase in wind and solar (and also reflecting hydrological conditions). Since 1996, cumulatively, general consumer price inflation has been 82% compared to retail electricity price inflation of 150% (Statistics NZ, 2023). Until 2018, the rise in wholesale electricity prices did not factor heavily into this retail price inflation.

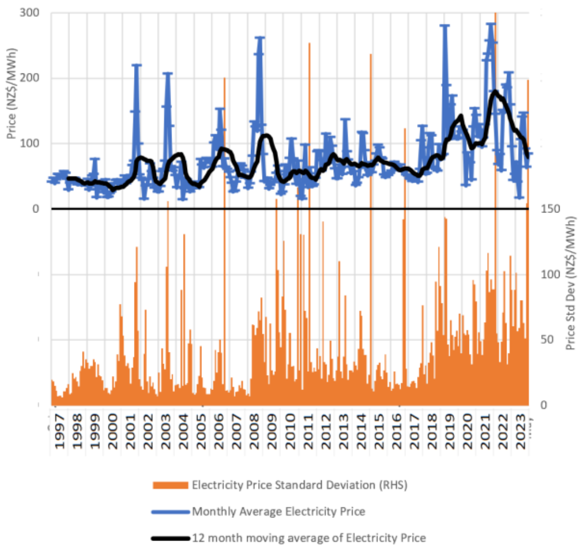

Figure 4: NZ wholesale electricity prices (monthly averages with 12 month moving average in black) and price volatility (as a standard deviation of half-hourly prices) from 1996 to 2023

5.2 Batteries

Figure 5 shows the NPV results for a 40MWh battery installation (based on current battery costs of approximately NZ$32M). This demonstrates batteries are still a loss-making proposition as a general solution to market volatility, though if grid-scale batteries continue to get cheaper (Cole and Karmakar, 2023) and New Zealand has more instances of market conditions similar to 2021 then the results indicate there may be a case for batteries in the near or medium-term future. The average NPV deficit from the last five calendar year simulations was $10M. This suggests a battery costing less than NZ$22M would be marginally profitable. This is a further 30% cost reduction.

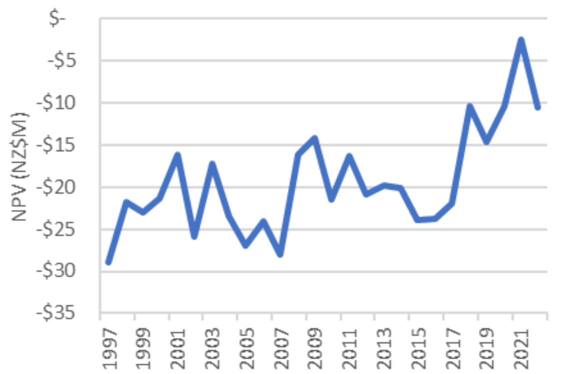

Figure 5: Net present value of a 40MWh battery project attached to a 100MW geothermal plant (on 2023 cost terms), noting that, historically, batteries would have been significantly more expensive than today's prices.

5.3 Last 5 years of flexible hydrogen production

Figure 6 shows how the last 5 years play out in terms of a set of flexible hydrogen production scenario simulations. Surprisingly, each year has a different pattern of utilisation, meaning seasonal production is not assured. The higher and more variable the prices, the more storage would be required to buffer out longer periods of no production.

Figure 6: Electrolyser utilization, cumulative mass of hydrogen produced and hydrogen mass in storage required while smoothing to constant output across the period. Those quantities are shown for five years spanning 2022-2018, in order from the top to bottom subplot.

5.4 Levelised Cost of Hydrogen

The following results have been calculated and presented as time series charts showing results for calendar year time periods to illustrate how electricity price volatility affects the case for flexible geothermal. Apart from electricity prices, all other inputs are held constant at 2023 levels meaning that, going back in time, LCOH will be inaccurate since the cost of equipment, for example, has changed.

Figure 7 shows the impact of electricity price on LCOH. When volatility is high it shows a divergence between the LCOH for constantly and flexibly produced hydrogen. The prices consider the electrolyser only and do not account for compression, liquefaction or transport. Compared to neighboring markets, Australian green hydrogen is projected to be at 2.70-3.20 US$/kg in 2030 (Menezes, 2023).

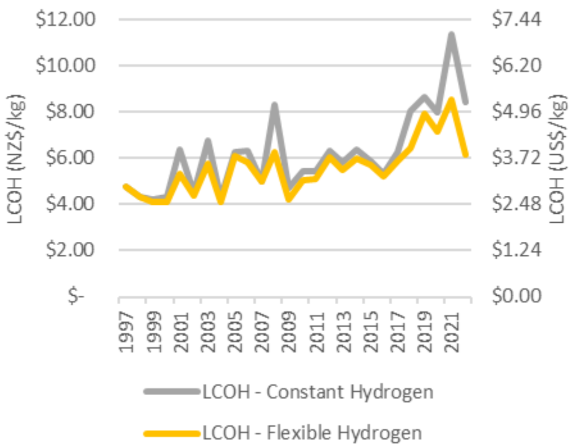

Figure 7: LCOH (evaluated on 2023 cost terms) for constant and flexible hydrogen production. The right-hand scale converts to $US.

5.5 Additional CAPEX for flexible hydrogen

Flexible hydrogen production with varying outputs throughout the year may not suit the market. It may be necessary to store some of the hydrogen produced to smooth the output to the market. To demonstrate how the lower per-unit cost of flexibly produced hydrogen translates into support for up-front capital expenditure such as storage, an additional CAPEX value has been calculated for each period. If hydrogen can be sold at or above the LCOH for constant hydrogen then producing using a flexible regime can justify additional capital expenditure up to the values shown in Figure 8 and still beat or equal the constant hydrogen production regime. If the necessary capital expenditure to make this production regime work is more than these values, then there is no commercial advantage to this regime in the current environment.

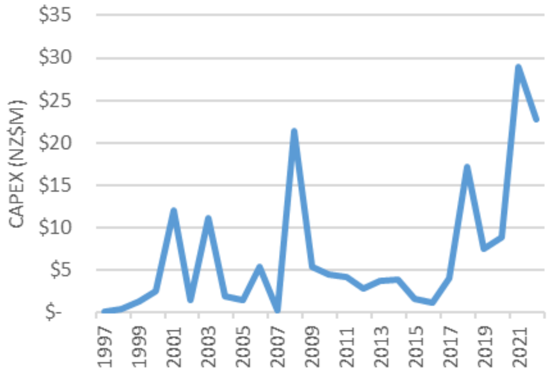

Figure 8: Extra capital expenditure available when producing flexible hydrogen while selling at the LCOH for constant hydrogen

5.6 Utilisation of equipment

Figure 9 illustrates how a battery is charging or discharging optimally 50-60% of the time. At other times the battery is either full or empty and forecast prices do not support taking any action. The charging/discharging patterns are fairly consistent year-on-year. The optimised utilisation of an electrolyser is dependent on the variability and magnitude of prices – the more the variability, the less utilised the electrolyser is since it is advantageous to exclude the more prevalent loss-making electricity costs.

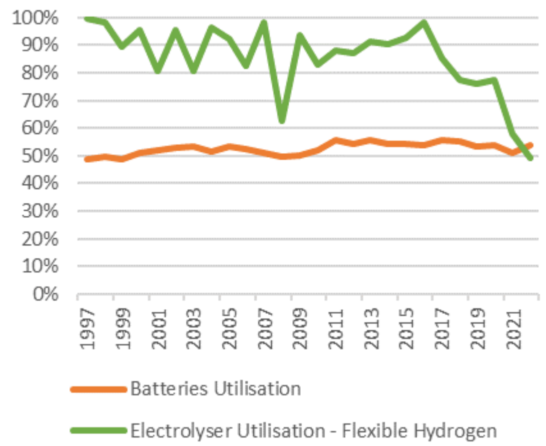

Figure 9: Utilisation of batteries and hydrogen electrolyser when optimised

5.7 Storage of hydrogen or methanol

Figure 10 shows the peak requirement for storage throughout the evaluated calendar years that would be needed to buffer the production and release at a constant rate to the market. This is a function of how concentrated the production is in one part of the year. The values in 2021 and 2022 are considerably higher than other years.

Liquid methanol storage has some special consideration though the requirements are similar to hydrocarbon fuels such as gasoline and kerosene (Narayanan, 2023). 4,000m^3 (the highest value in Figure 10) can be visualised as four Ø12m by 10m high silos, and may be sited above or below ground.

Liquid hydrogen is a different proposition entirely. It will not store for long due to vent-off losses and the storage facility capital and running costs are orders of magnitude higher than for methanol. The costs to liquify the hydrogen for bulk storage may add as much as NZ$50M to the upfront facility costs (Connelly et al., 2019) as well as more electricity consumption. The largest liquid hydrogen storage tank in the world is at Kennedy Space Centre in Florida and has a usable capacity of 4,732 m^3. Two of these tanks would be required to store the volume needed to smooth production in years 2021 and 2022, which is not considered economically practical.

Compressed hydrogen at 700 bar would be less dense but potentially less costly and incur less losses for long-term storage. The density of 700 bar hydrogen gas occupies 69% more volume than liquid hydrogen and so the 2022 storage volume would need to be 13,900m^3. Setting up a storage facility with this volume is also an impractical undertaking.

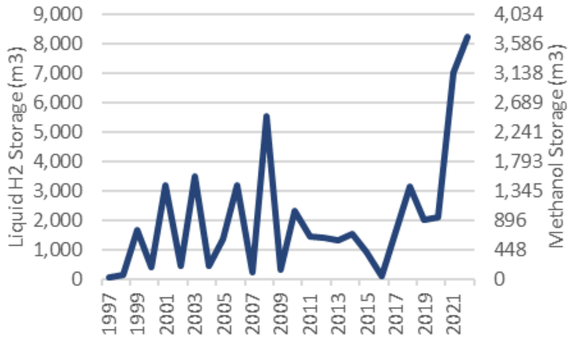

Figure 10: Storage volumes required to buffer a flexible hydrogen production regime to achieve a constant supply

6. DISCUSSION AND FUTURE IMPROVEMENTS

- Real-world trading logic and forward pricing uncertainty have been simplified in these simulations. Even though final pricing is not available until after the fact (now a real-time market in NZ), forecast prices are available to the market and generally reliable many periods in advance. A forecasted price data history is available and with further analysis could test and improve assumptions for how predictable prices are in advance and how successful decision logic and trading algorithms will be.

- The charging/discharging algorithm used for batteries was very basic and could be optimised to achieve a small amount of further revenue. The forward averaging periods resulting from the battery logic optimisation were generally stable at about 6 trading periods for battery capacity-to-charge ratios of 2:1 and around 12 periods for charge ratios of 4:1. This suggests the optimum patterns for charge/discharge currently follow predictable cycles and smart algorithms may have only limited impact on productivity.

- The unit cost of a battery should be a function of total capacity and capacity-to-charge ratio in accordance with Tesla Megapack pricing. This has not been optimised. Other battery suppliers have not been explored so far.

- Further accuracy could be added in estimating costs. So far, the estimates used are at the most basic level. Cost histories could also be implemented for the equipment to give a more accurate history of LCOH evolution for the purpose of better understanding the trend. This may help to forecast future performance.

- Forecasting will require gathering a prediction of future costs and developing beliefs of the evolution of the electricity market according to demand changes and new generation projects. While significant data are available for this and a new Electricity Demand and Generation Scenarios study is due to be released by MBIE in 2023, there is still significant uncertainty involved over a 15-year or even 10-year project timeframe.

- Further exploration of the benefits of flexibility schemes in various organizational contexts could be conducted. If flexibility is internal to the same entity, or in the context of a gentailer (combined generator and retailer) compared with an independent demand-side entity on the grid then outcomes may differ. This might include making use of market instruments or exploring new incentive schemes.

- Transmission capacity and the possible need for upgrades are not factored in. In some cases, this will add significant cost where there is potential to increase peak output from the geothermal facility but the transmission lines are already at capacity. There may also be additional benefits to reducing output at times of high transmission loss or constraint.

- An intermediate case is possible between constant and flexible hydrogen schemes. A demand response situation could be implemented and may have some advantages in equipment design and supply agreements. For this scheme, hydrogen production would stop or reduce for medium-term periods according to a market mechanism that signals a need to conserve supply rather than responding directly to market pricing.

7. CONCLUSIONS

- The average price of electricity and volatility have been elevated for the last five years and was particularly high in 2021. As New Zealand continues to push for higher levels of renewable electricity, the volatility may continue or worsen until changes can be implemented.

- It remains difficult to make a general case for grid-scale batteries based on current equipment pricing. However, the conditions in the market in 2021 came close to supporting a break-even situation (assuming these conditions occur more usually in the future). If battery costs continue to drop, they may be justified to enter service to counter intra-day fluctuations. According to this analysis the further cost reduction would need to be at least 30%. However, batteries will not address seasonal fluctuations since the amount of energy storage required far exceeds what is practical.

- Constant hydrogen production by electrolysis is expensive due to the average electricity cost. If larger electrolysers are purchased and hydrogen is produced only (or at higher rates) when wholesale electricity prices are below a threshold cost then, for the last few years, this yields a significant improvement in the levelised per-unit cost of hydrogen.

- There is perhaps a case for hydrogen production if it can be sold or utilised in downstream processes at prices of NZ$8/kg (US$5/kg) or above. The corresponding threshold electricity price would be NZ$145/MWh, meaning that based on 2021 prices electrolysers would be running 55% of the time.

- If demand for the hydrogen product is constant then storage facilities would be required to smooth out supply to support a flexible production model. The volumes of hydrogen storage required to smooth across the whole year are impractical with current technologies.

- The use of hydrogen as an input to produce a liquid such as methanol (or other e-fuel or e-chemical such as sustainable aviation fuel) makes storage more feasible. The liquid storage volumes would be practical, conventional storage facilities and would not particularly compromise the economics. This mode of production would also have utility to counter seasonal variations and reduce pressure on the dry year problem, thereby enabling higher renewability in the electricity system.

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