Ministry of Business, Innovation & Employment Hikina Whakatutuki

NZ BATTERY PROJECT

OTHER TECHNOLOGIES FEASIBILITY STUDY

Feasibility Assessment Report

11 NOVEMBER 2022

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Feasibility Assessment Report

Ministry of Business, Innovation & Employment Hīkina Whakatutuki

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	NAME	DATE	SIGNATURE
Prepared by:	WSP Team	30-Sep-2022	Privacy of natural persons
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11 November 2022

Privacy of natural persons

Energy Projects & Programmes, Energy & Resource Markets
Ministry of Business, Innovation & Employment | Hikina Whakatutuki
Level 11, 25 The Terrace, Te Puawai o te Aroha – Pastoral House, Wellington

Dear Privacy of natural persons

NZ Battery Other Technologies Feasibility Study

6-P0264-RPT-0235 Rev 2 Feasibility Assessment Report

Please see attached the Feasibility Assessment Report, updated to incorporate final comments received.

We appreciate the opportunity to have provided input to this potentially transformative opportunity for New Zealand. Looking ahead, we would welcome the opportunity to work with the MBIE NZ Battery Team further, as required, on next steps for this Project.

Yours sincerely

Privacy of natural persons

Project Manager, WSP

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150 YEARS IN AOTEAROA

Executive Summary

INTRODUCTION

The Ministry of Business Innovation and Employment (MBIE) is investigating options to manage or mitigate New Zealand's "dry year problem". A feature of New Zealand's highly renewable electricity system has been that our reliance on inflows into our hydroelectric dam reservoirs make us susceptible to potential shortages in "dry years". In the future, with more of our electricity supply coming from wind and solar generation, the problem may become a "dry, calm or cloudy year problem".

The NZ Battery Project has been tasked with finding a solution to this problem in a way that supports New Zealand's commitment to climate change mitigation and a 100 percent renewable electricity future. The Project has several workstreams investigating the various parts of the problem. Globally, interest in energy storage to unlock greater renewables penetration is on the rise, although not generally at the scale and duration that Aotearoa New Zealand seeks. In this regard, the large-scale nature of the NZ Battery Project is unique.

SCOPE OF WORKS

WSP was engaged by MBIE to review several alternative, non-hydro technologies that could potentially help to manage, or mitigate, the dry year problem by storing 1–5 TWh of electricity (or equivalent schedulable generation releasing energy only when required) from 2030. These "Other" Technologies may be considered as stand-alone options for the NZ Battery, or as building blocks for a full solution. The range of storage sizes considered, with a lower end around 1 TWh, reflects the potential for smaller scale solutions to be included in a portfolio solution.

The ultimate outcome of the Other Technologies Feasibility Study is to determine which, if any, alternative technology option, or combination of options, should be taken forward for further investigation and consideration alongside a pumped hydro solution, as part of a detailed business case.

The Other Technologies Feasibility Study comprises two main stages:

- The first is the Options Analysis, which focused on the review of five non-hydro renewable technologies, to recommend a smaller number of Prospective Options for further study. During this stage Biomass, Geothermal Energy and Hydrogen were selected as Prospective Options, with Air Storage and Flow Batteries being excluded from further review.

- The second is the Feasibility Assessment (documented in this report). This includes technical and commercial feasibility assessments of the Prospective Options, including the viability of integration and deployment by 2030 in New Zealand. This assessment will help inform the decision as to whether any should be developed further (as an Advised Option).

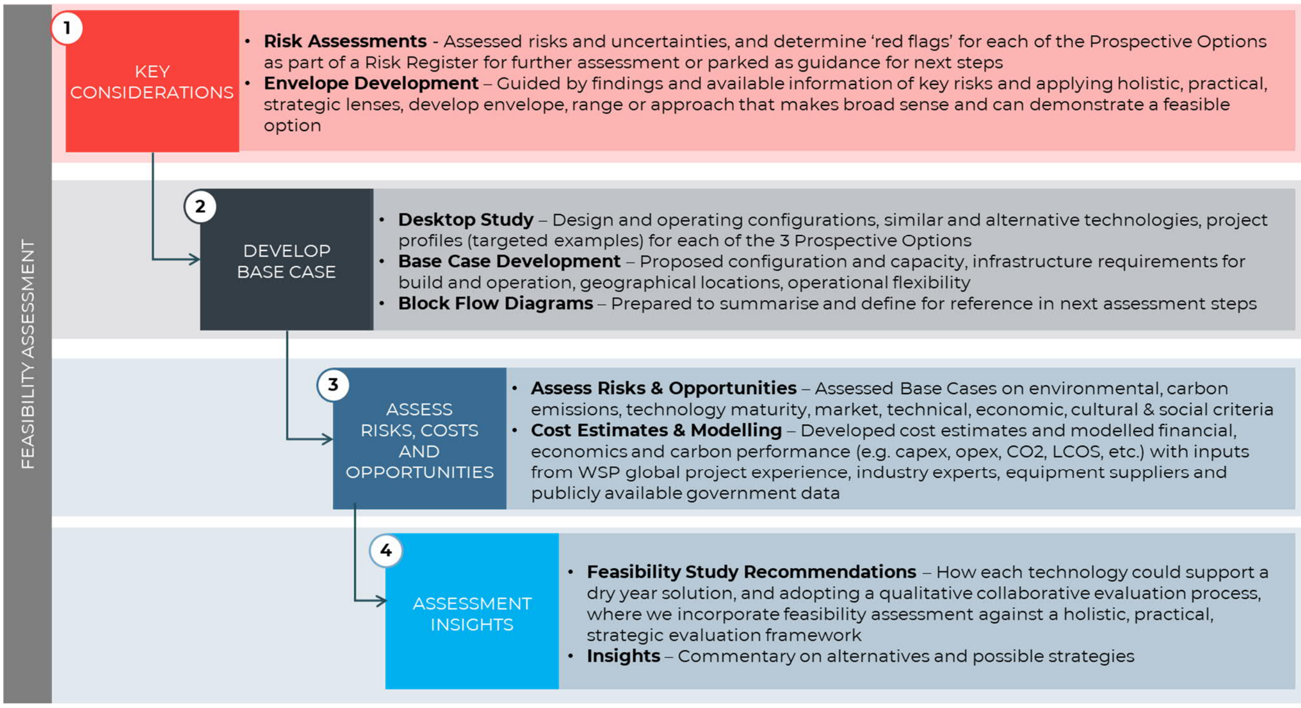
APPROACH

Over the course of the Feasibility Assessment, WSP's global team members, together with MBIE's NZ Battery Project Team (including support from other subject matter specialists) applied a structured process to evaluate each of the Prospective Options.

The assessment approach is aimed at achieving a technology or portfolio of technologies capable of providing large-scale, long-term, renewable energy storage. The options were not generally constrained by the need to identify specific locations, the need to align with any existing energy sector assets or developments, or whether the NZ Battery should be centralised into one location or distributed.

The work involved sharing drafts of findings for discussion, reviews and feedback, assessment workshops, technical and evaluation challenge sessions to arrive at the recommendations.

The main steps undertaken are summarised below:



The findings and recommendations for the feasibility assessment are recorded in this Report, with a focus on how each option could best support a dry year solution. Also included are additional insights, which serve as commentary on alternatives and possible strategies to address common questions or issues, when deploying such technologies. Guidance on next steps is provided alongside an indication of schedule for engineering, procurement and construction works up to commissioning stage.

BIOMASS

The previous Options Analysis work revealed over 50 possible bioenergy sources, which included crop residues (straw, stover), oil crops (rape, sunflower), fermentable crops (corn) and industrial waste from a range of sources (dunnage to used vegetable oil). It also considered other options such as the ethanol derived from softwood.

The option of a woody biomass feedstock based on debarked *pinus radiata* logs, obtained on a spot market and harvested from sustainably managed New Zealand forests, was found to most closely align with NZ Battery Project criteria.

OVERVIEW OF A BIOMASS NZ BATTERY SOLUTION

As a NZ Battery solution, biomass appears to present a robust option. It would use large regions of existing national exotic forestry. The technology has high maturity, reliability and efficiency and could provide a self-reliant New Zealand solution with high independence from international influences.

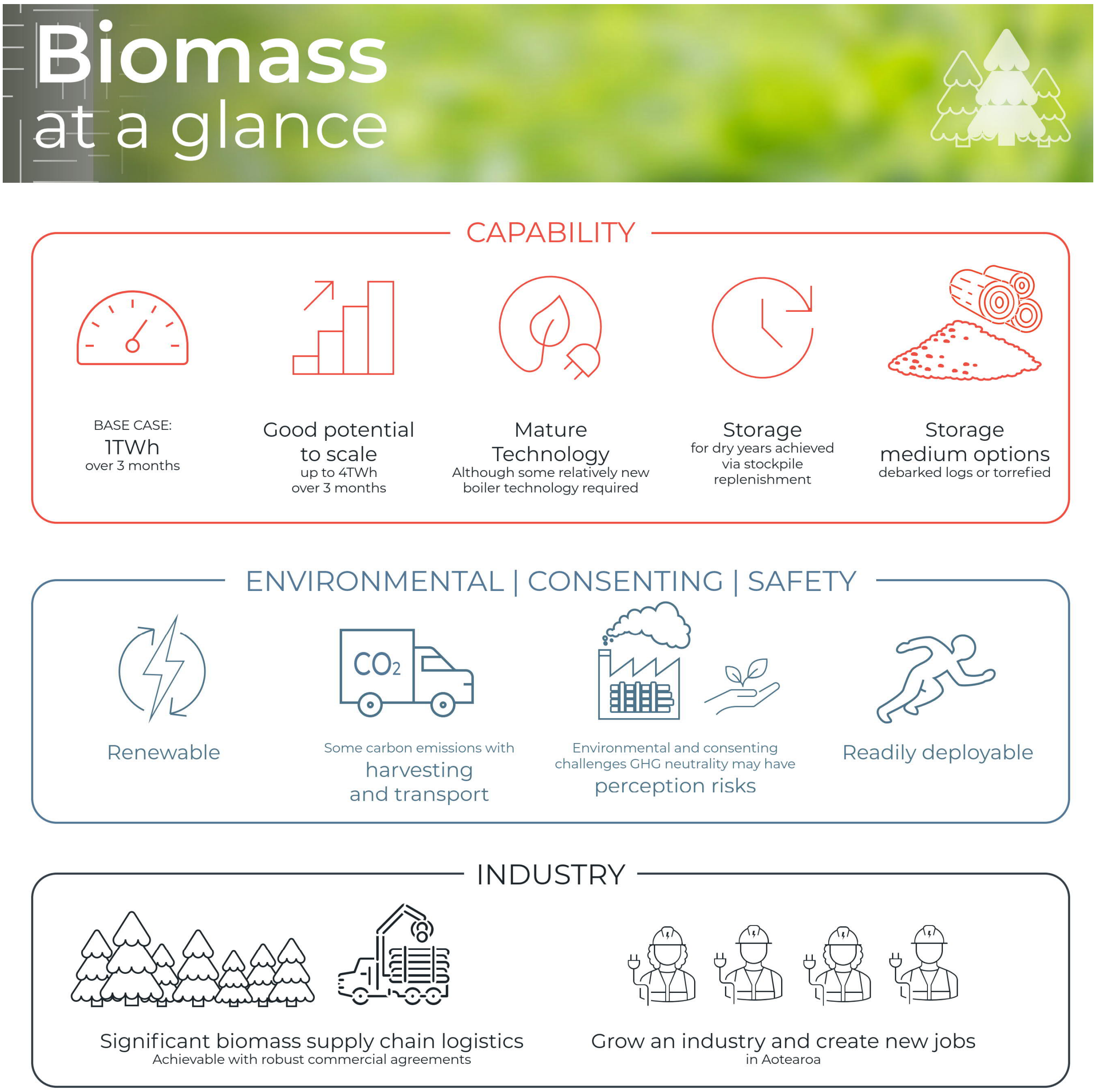
Exotic forestry that would be used in the solution is sustainably managed and deemed GHG neutral. While the base case has been set at 1 TWh (to balance biomass demand against competing uses/exports and supply chain constraints) it could feasibly go to as large as around 4 TWh, in a staged approach that managed risks. This will require extensive commercial discussions with prospective biomass suppliers, together with significant stakeholder involvement.

The challenges for biomass predominantly relate to the supply chain and storage duration. Due to the limited duration of biomass storage (approximately two to five years, depending on storage medium selected), stock replenishment may be required. This results in an ongoing supply chain cost and potential need to utilise expiring biomass. The supply chain requirement also results in associated carbon dioxide emissions. The 1 TWh size has been used to limit the collection radius required for logs, reducing transportation requirements.

A base case of white biomass (log chips) has been used, but an option of torrefied biomass (with potentially longer storage durations) remains a possibility. There is insufficient track record information available to finalise the optimum storage medium at this stage. To navigate this uncertainty, a staged approach to decision-making has been proposed, that will ultimately lead to a NZ Battery solution for the required 2030 operation date.

New Zealand also has existing plant that can likely be modified to use biomass (either torrefied or similarly thermally treated). The remnant life of such plant is not known, but even if the remnant life were relatively short compared to the proposed life of new plant, a capex deferral option could be attractive.

From a benefits perspective, the supply chain requirements result in long-term, local employment benefits due to the job creation opportunities associated with the relatively labour-intensive biomass harvesting and supply chain logistics that would be permanently required, as well as seasonal dry year work gains.



KEY CONSIDERATIONS

The key considerations that shaped the development of a Biomass NZ Battery solution are summarised below.

Biomass availability and logistics: Woody biomass resource is currently commercially contracted, so access would be on a negotiated basis, to either access a portion of the contracted resource, or support scaling up of the resource to increase supply. We have considered the current volume of logs exported as one potential indicator of what could be available. The volume of logs required has haulage implications, with increasing volumes of logs resulting in larger transportation distances and associated CO_2-e emissions, which have also been considered.

We have recommended that the base case for this Feasibility Study is limited to a 1 TWh storage solution, equating to a log supply of approximately 560,000 tonnes[1] per annum. This scale is felt to best balance the various risks on supply – competing demands on the biomass, the ability of the supply chain to realistically flex for the storage demands, and challenges around transport and storage logistics.

The 1 TWh isn't deemed to be a hard limit on the biomass supply and an extension potentially up to 4 TWh could be considered, if sufficient certainty of supply could be secured through commercially suitable arrangements.

Te Ao Māori: The biomass technology option proposed aligns with, and implements, the objectives of the Ministry for the Environment's Aotearoa NZ Emissions Reduction Plan for Empowering Māori as part of the Circular Economy and Bio-Economy. However, this option is dependent upon supply side agreements with iwi and effective iwi engagement, which should ensure that iwi work together with the Crown to determine how the biomass technology sector is structured and how it functions. Care should be taken to ensure alignment with the relevant Treaty of Waitangi Deeds of Settlements, and iwi/Māori forestry leadership is leveraged in meeting the objectives of the NZ Battery Project.

Storage fuel type: Biomass is a biogenic substance and, once harvested, its durability affects the length of time it can be stored and then fed into a generation plant efficiently. Biomass can be stored as logs, chipped, ground, pelletised or torrefied (thermally treated). The storage lifetime of the biomass is not known with certainty but expected to range from two to three years for logs, and potentially up to five years for torrefied biomass. Given that the duration between dry years is not fixed or known, the ability to rotate or replenish a stockpile, as and when the biomass becomes unsuitable for power generation, is needed.

For the base case, we have opted for a debarked log stockpile with a three-year replenishment period. The torrefied alternative could offer a longer replenishment period but involves higher supply chain variability and a higher quantity of biomass logs for the same generation output. In addition, it introduces the need for torrefaction facilities and the associated introduction of a single point of failure. Torrefied biomass is still a viable solution for the NZ Battery, but for the purposes of setting a base case, we have not included this step.

Generation plant technology: For large-scale power generation, coal-fired plant is far more common globally than biomass-fired. For a biomass NZ Battery, one option would be to utilise generation plant designed specifically for coal and accept a risk that it may prove challenging to convert biomass to a form with properties sufficiently close to coal, such as torrefied biomass. In taking this approach, it would be necessary to accept the significant parasitic losses incurred to modify (torrefy) biomass to approach coal-like properties. As set out above, at this stage torrefaction has not been included in the base case design.

The option selected is to use generation plant that can operate satisfactorily on the wettest and least uniform biomass. A solution within 600 MW range of generation and achievable fuel consistency would be boiler technologies including Circulating Fluid Bed (CFB) types, which are less common than coal plant, but have acceptable technical risk and offer a significant degree of flexibility in fuel specification.

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[1] Charging or re-charging the battery over a 2-year period

GHG neutrality and sustainability: As with all sustainably harvested biomass, exotic softwood is essentially GHG neutral (i.e. by replanting what is harvested). However, since the combustion of biomass creates greenhouse gas emissions, there is a risk that a biomass NZ Battery is perceived as not being renewable or GHG neutral. Our study included the assessment of the GHG neutrality of a biomass NZ Battery solution, using a randomly generated dry year model and illustrates that annual net zero carbon emissions can be achieved, provided that all harvested trees are replaced. The emissions from biomass combustion are demonstrated to be balanced by the growth of renewed forest over the long term.

IMPLEMENTATION APPROACH

The development of a biomass NZ Battery solution will require a staged development and decision process to refine the solution to be implemented.

To address the uncertainty of the durability of logs as an energy storage option, an early trial is suggested, which would require *pinus radiata* logs to be harvested and stored alongside torrefied pellets in controlled conditions, with regular testing for quality and durability. The development process will also involve significant commercial discussions with prospective biomass suppliers, together with extensive stakeholder involvement. A critical component of this would be early discussion of Te Ao Māori values with Iwi partners, who are both significant forestry landowners and forestry industry management operators.

We have provided a high-level representation of a potential biomass solution development pathway that allows time for these critical phases to occur. Also developed is a biomass supply chain, storage life and energy conversion calculation model that allows the user to fully adjust the major supply chain parameters, storage medium and test sensitivities. The tool can be used, together with costs and insights of other factors, to help develop an optimised solution that best addresses NZ Battery Project objectives.

COSTS

Biomass Total Lifetime Class 4 Cost Estimate			
	Base cost	50th Percentile (P50)	90th Percentile
Total Cost at PV - excluding revenue ($M)	Commercial Information		
Total Cost at NPV – including revenue ($M)			

Revenue included relates to the sale of electricity when generating during the dry year period, plus additional generation from logs from the stockpile that are “expired”.

RISKS AND OPPORTUNITIES

There are a number of risks and opportunities for the NZ Battery Biomass solution, which are fully detailed in Appendix G. We would highlight the following:

Opportunities	Risks
New Zealand develops technical expertise and capability in technologies relevant for decarbonisation	The logs deteriorate faster than assumed and handling becomes more challenging
Growth of forestry sector with commercial benefits, as well as local job creation in construction and operation	Consecutive dry years occur causing biomass fuel shortage
Re-use/re-purpose existing generation plant (if selecting torrefied biomass)	A biomass battery solution is perceived as not being carbon neutral
Use replenishment discarded log stock to feed other biomass consumers, rather than for generation	Ideal sites to develop the Battery project are not available, leading to challenging consenting processes, delays and increased costs.

GEOTHERMAL

Establishing a geothermal NZ Battery would involve bringing forward a number of geothermal stations that would otherwise not be implemented until after 2030 and operating them in a new way i.e. as long-term “controlled schedulable” plants that can ramp up electricity generation in dry years, as needed. Traditional geothermal power generation technologies would be used, with the inclusion of some additional engineering design, operating and maintenance features. These additional features would allow the below-ground geothermal reservoir to be run at a low load (turned down) condition, while allowing several of the above-ground power plants to be switched off (mothballed) during normal years, in readiness to then be ramped up and run at full load in dry years.

OVERVIEW OF A GEOTHERMAL NZ BATTERY SOLUTION

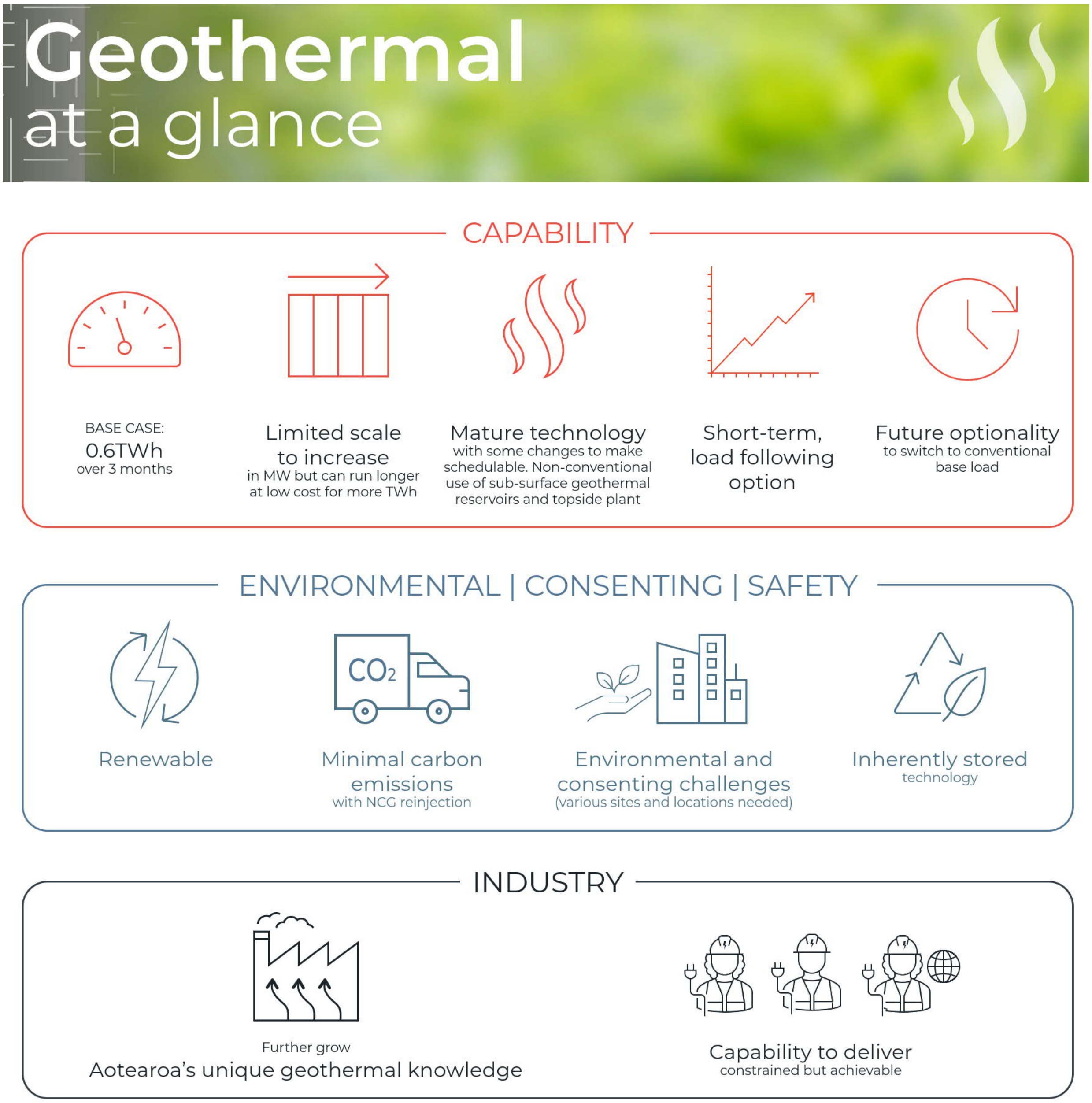
Geothermal energy for a NZ Battery solution presents a unique opportunity, as its energy is inherently stored and does not need to be “recharged” like other technology options. The base case has been designed around an appropriate feasible solution for the NZ Battery, which is to provide 300 MW of additional generation, corresponding to 0.6 TWh over three months. However, it also has potential to continue running and provide more dry year back-up energy, as required over longer durations, with minimal additional cost.

Geothermal is a well proven technology in New Zealand, with many sites already in operation. The risks for this solution are mainly limited to the long-term operation of the wellfield in a schedulable manner. While not considered high risk, it is non-standard operation and there is limited track record for this kind of operation. CO_2 extraction and reinjection is incorporated in the base case, to minimise surface environmental effects and maintain reservoir pressure. This has also not been done before at full scale but is not considered high risk, with trials already being carried out at several sites in New Zealand and overseas to demonstrate commercial feasibility.

A challenge with geothermal is the constraint on how much can be built as part of the Battery before pushing against the limits of what would otherwise be built as mainstream generation, effectively creating an upper limit on what can be used to provide a stand-alone battery.

The 0.6 TWh solution proposed would involve developing multiple geothermal sites, which also adds some challenge and complexity to this solution. While considered to be achievable, based on previous country development rates and the ability for international development support, there will still remain some risk around development timeframes due to the quantities of drilling required and the technical expertise available. The developments will also require significant consultation with stakeholders, including local iwi, to ensure the co-operation of kaitiaki and incumbents. This could slow down development timeframes but ultimately could provide economic and social opportunities for Māori groups and communities.

As part of base case design, efforts have been made to avoid oversizing the development for the field. Installed capacity has been limited to the expected baseload capacity when the field is fully developed. An implication is that, once a field has been operated and the sustainable capacity is proven, it may be possible to transfer some plant to normal market operation, if desired. In this regard, geothermal offers good future optionality, as well as a relatively safe, “no regrets” solution for New Zealand.



KEY CONSIDERATIONS

The key considerations that shaped the development of a Geothermal NZ Battery solution are summarised below.

The role of kaitiaki and incumbents: Māori have strong links to New Zealand's geothermal resource, for whom it is a taonga. Many of the associated trusts have a kiatiakitanga role and, as such, are interested in partnership or leadership of geothermal developments. There are also a range of incumbent field developers who may already have exclusive geothermal development rights and will typically hold the detailed technical knowledge on a geothermal field and its capability. A partnering approach with kaitiaki and incumbents would bring multiple benefits, as these parties can bring commercial knowledge, support for consenting, exploration and implementation contract management and also provide ongoing operations and maintenance.

Sub-surface and well operation: Using geothermal energy as a NZ Battery solution will require it to operate in a non-traditional way. This means, rather than running at full capacity in a normal year, the subsurface reservoir would need to run at low load (be turned down) or be entirely shut in and only be opened up when needed for NZ Battery duty. Traditionally, most geothermal systems operate on a continuous basis, with constant flow and temperature profiles, in order to minimise sub-surface risks and maximise well performance. Therefore, it is recommended that the geothermal reservoirs are run in a low load mode rather than be fully shut in (on/off) during normal years. The wells would, therefore, operate at constant low load, then step up to new constant levels, as required, during dry years.

NZ and international geothermal industry capacity: Even though New Zealand has a strong existing national geothermal industry capability, the deployment of a significant quantity of new geothermal plants by 2030 would likely stretch capacity. With the large-scale nature of the NZ Battery Project, a geothermal solution would need to be split across multiple sites, developed, consented, designed and constructed, at least partly in parallel. This would present a resourcing challenge i.e. sourcing sufficient geothermal industry specialists to carry out the research and engineering required to develop the geothermal stations, in addition to any business-as-usual developments. The solution to this would be to utilise international expertise for support and limit the amount of new generation (based on previous on-shore and off-shore geothermal new build campaigns) to what can realistically be achieved in the timeframe.

Geothermal Carbon Dioxide (NCG) extraction and reinjection: As part of a national aspiration to transition to low CO_2 emission electricity generation, CO_2 (and other gas) emissions from the geothermal battery should be further minimised. To achieve this, it is recommended that the geothermal NZ Battery includes CO_2 extraction and reinjection, in accordance with the best practices and systems identified during recent New Zealand and international CO_2 reinjection system trials.

Opportunity cost of displacing business-as-usual geothermal development: A challenge with geothermal energy generation is the constraint on how much can be built, before pushing against the limits of what would otherwise be built, given geothermal is an important part of New Zealand's "stack" of future renewable generation projects. Accordingly, there is an upper limit on what can be used to deliver a stand-alone battery.

BASE CASE DESCRIPTION

The proposed base case is to build 400 MW of new greenfield geothermal power stations at several (currently undeveloped) sites, distributed across New Zealand's known geothermal regions (primarily the Taupō Volcanic Zone). Each plant would typically be built in modules, which could then be brought on, as required, for dry years in controlled increments, depending on the extent of the energy gap.

BASE CASE OPERATION

In normal years, the plant at each site would run at low turn-down, by modulating the sub-surface wells to roughly 25% open and running one topside unit of geothermal plant at full load, with other units mothballed. In dry years, the plant could be ramped up over approximately two weeks to 100% (or a chosen mid-range point to suit the dry year requirement) by opening up the sub-surface wellhead valves, de-mothballing and ramping up the topside geothermal plants to bring online an additional 300 MW of dry year back-up generation. The 300 MW of additional generation equates to 0.6 TWh of energy over a three-month period.

IMPLEMENTATION

It is expected that the two main geothermal plant types (Condensing Steam and ORC Binary) will be deployed. Both technologies can be configured to provide long-term schedulable operation. In addition, the ORC Binary plant may also be able to provide the option of flexible, short-term load following operation, if this were to proceed as part of the project. This combination of plant types, and the conceptual scale of the proposed solution, aims to be realistically achievable with New Zealand-based and international geothermal industry participation.

A portfolio development approach to fields would be recommended, in order to spread development risks. The fields at the back of the MBIE generation stack are generally greenfield, so there will be uncertainty about eventual production capability. To minimise these risks, exploration drilling prior to pursuing full development consents would be scheduled into a comprehensive project-wide schedule approach.

The portfolio approach would allow for differing rates of progress with potential partners, including iwi representative groups and commercial entities, and would be reliant on effective collaboration. It is emphasised that, although “back of the stack” fields are considered here, there have been no discussions with any parties or specific plans made for any field.

COSTS

Geothermal Total Lifetime Class 4 Cost Estimate			
	Base cost	50th Percentile (P50)	90th Percentile
Total Cost at PV - excluding revenue ($M) -	Commercial Information		
Total Cost at NPV – including revenue ($M)			

Revenue included relates to the sale of electricity when generating during the dry year period plus generation and sale of additional electricity when running in turned down mode during a non-dry year.

RISKS AND OPPORTUNITIES

There are a number of risks and opportunities for the geothermal Battery solution, which are fully detailed in Appendix G. We would highlight the following:

Opportunities	Risks
NZ could develop new technology or geothermal plant operating techniques and enhance Aotearoa’s status as a global leader in this industry - with related knowledge export benefits	Long-term operation of the wells in a schedulable manner is impacted due to subsurface issues

Could be developed in collaboration with local iwi and private market.	Lack of appropriate available sites leading to challenging consenting, delays and costs, particularly as greenfield geothermal resources may be relatively unpredictable
Reduced normal year load factor could increase dry year energy capacity	Insufficient technical expertise limits the implementation at required scale and timeframe
Option to also provide short-term load following, in addition to dry year back-up supply	Use of geothermal resource (taonga) negatively impacts Te Ao Māori
Additional revenue streams via removal of silica and other minerals	Construction across multiple sites negatively impacts communities

HYDROGEN

Green hydrogen is being pursued globally as a critical enabler to decarbonise hard-to-electrify elements of the energy system. It facilitates the integration of renewably produced energy because hydrogen and its derivatives offer a chemical energy storage medium that can be transported or piped at large-scale to locations required for end uses, including electricity generation, at a future date. The previous Options Analysis task led to green ammonia (a hydrogen derivative) being considered as the most viable hydrogen energy vector for the NZ Battery Project, largely due to its technological readiness and ability to be stored and transported at large scale.

OVERVIEW OF A HYDROGEN NZ BATTERY SOLUTION

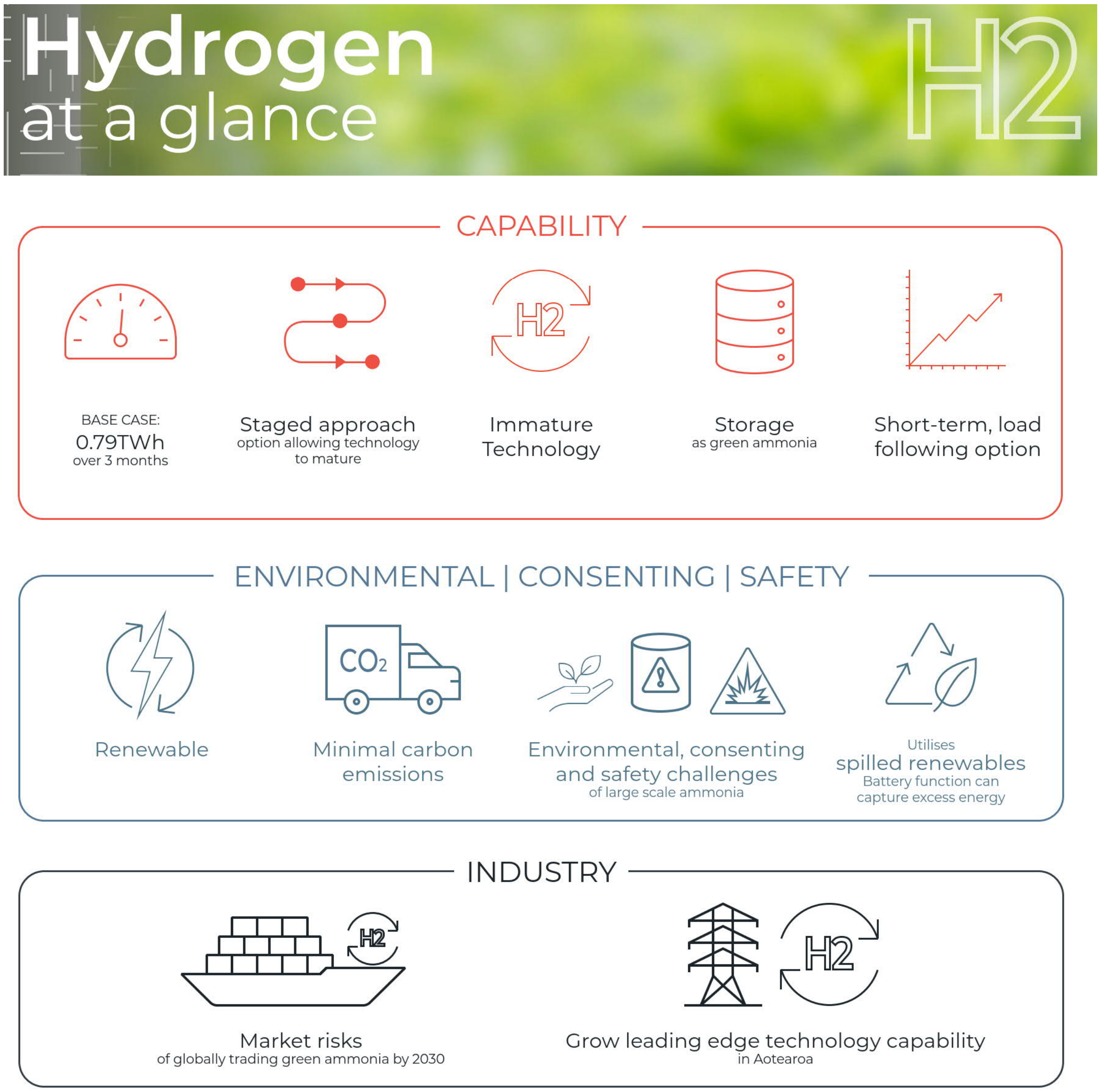
As a NZ Battery solution, green hydrogen offers an interesting long-term dry year solution with minimal carbon emissions. The proposed base case includes hydrogen and ammonia production, with ammonia storage, both for export (to provide demand response) and for local generation. Not all of this solution could technically be classed as a battery, but ultimately provides the same result as a battery with a 0.79 TWh dry year coverage over three months.

While carrying some market development risk, the flexibility to export or import green hydrogen offers the opportunity to increase the dry year response beyond 0.79 TWh, either by increasing hydrogen production (and hence demand response available) or supplementing local production with imports.

A hydrogen solution incorporating export also brings significant opportunities that could benefit New Zealand. It could provide the ability for renewable electricity generation to be expanded beyond what is needed on our shores and the export of a 100% green energy product to the world. As well as assuring New Zealand's long-term electricity security, it may provide a new economic value chain and high value, innovative industry knowledge benefits.

The hydrogen opportunity does, however, present risks around the maturity of plant for hydrogen generation and the need for a green ammonia international trading market to develop, enabling the reliable, long-term export of this product. In addition, there are risks associated with the safety of large-scale ammonia storage, requiring a suitable location that adheres required separation distances, and with consenting potentially challenging due to public perception.

Due to its relatively low level of technical and commercial maturity, the risks associated with a hydrogen solution have correspondingly high levels of uncertainty. In this respect, to mitigate against these risks and uncertainties, a hydrogen option could be best considered for staged deployment in smaller scale increments. This could potentially be done in conjunction with other options, deferring the need for a full-scale hydrogen system until both the technology and market have matured.



KEY CONSIDERATIONS

The key considerations that shaped the development of a Hydrogen NZ Battery solution are summarised below.

Technology Maturity: Despite recent developments in hydrogen-based energy solutions, there remains a steep learning curve for large-scale electrolysis, flexible ammonia synthesis, ammonia cracking and hydrogen power generation, leading to some uncertainty in achieving technical maturity by 2030. If sanctioned today, New Zealand would be among the early adopters of a green ammonia plant at the scale required for the NZ Battery.

To navigate the uncertainty of technology maturity, the base case developed has intentionally included a range of potential elements ("building blocks") that could make up an eventual project solution. These blocks allow for different possibilities in the way ammonia is used, by providing infrastructure to allow:

- Large scale green hydrogen production with international exportation. Dry year coverage by demand response

- Bulk storage of green ammonia, which can be converted back to hydrogen for electricity generation in dry years
- Optional importing of green ammonia to top up storage.

Risks can be managed through the development process in different ways, for example:

Technology risk	Mitigation
Flexible ammonia synthesis	A nominal amount of hydrogen buffer storage has been included in the base case. The scale of this buffer can be increased to further mitigate flexibility risks.
Ammonia cracking plant maturity	Should ammonia cracking maturity not develop in the required timeframes, deployment of ammonia-to-hydrogen-fuelled electricity generation can be deferred to post-2030 and rely only on demand response prior to this.

Large scale storage of green ammonia: Ammonia is a hazardous substance that is toxic, corrosive and flammable. Provided safe design and the establishment and compliance with storage, handling, operating and maintenance procedures, anhydrous ammonia storage is generally considered safe. However, great care will be needed to minimise the likelihood of a release scenario, which could have catastrophic consequences to life and environment. The ability to suitably mitigate this risk is seen as critical to the overall viability of this solution.

Both the likelihood and consequence of a release scenario increases in line with increased storage volume. Following investigations into tank type and size options, the base case proposes storage of liquified ammonia in four 50,000 m^3 capacity, full containment (double-skinned) tanks with a total storage of approximately 200,000 m^3. This size of tank is regularly used around the world and carries less risk than larger tanks being proposed for some projects overseas, as well as being smaller in size than the largest storage currently in New Zealand for hazardous refined products. As well as reducing safety risks, this storage capacity is also considered to reduce potential consenting hurdles.

A risk assessment modelling exercise was carried out by WSP that dictates appropriate separation distances from sensitive receivers e.g. highways, railways, places of public assembly, hospitals and residential, commercial, and industrial buildings. Suitable locations are believed to be possible in New Zealand.

Hydrogen production as a demand response: Due to its large electricity demand, hydrogen electrolysis could act as a form of demand response i.e. producing hydrogen in non-dry years using any available variable, off-peak renewable power and then halting production in dry years to release the load back into the system. Sizing of the electrolyser load is, therefore, a key consideration of a demand response solution i.e. maximising the demand response available, but balancing this against economically viable additional generation that could be developed and the risk of creating too much hydrogen for storage or export.

For the base case, we suggest a grid-supplied production plant power supply load of 369 MW is suitable for demand response. When factoring in the time-weighted load factor, this provides 0.5

TWh over 3 months. An upper range of around 739 MW production plant supply load could be possible (providing 1.0 TWh of dry year demand response over 3 months) but is deemed more of a stretch when considering increasing demand associated with the general electrification of industry. Consultation with Transpower and potential developers would be required for the next phase of this development.

International market development risk: The sizing of hydrogen and ammonia production facilities and the economic feasibility of the demand response option is dependent on the international market for renewable ammonia. For international renewable ammonia markets to function effectively, there is a need to differentiate (physically identical) green products from brown, via an internationally recognised certification scheme(s) and a spot market to sell renewable ammonia. We believe that, while a market will likely exist in 2030, it may not be in the form of a truly global, tradeable commodity with a spot market for a number of years beyond 2030. It is likely that in early stages sale would need to be through an off-take agreement to enable project financing to be secured.

The base case is sized to serve a modest green ammonia export market, as well as replenishing ammonia storage to meet dry year generation demand. If there is a reasonable expectation at the time of project sanction that this market is not developing, then the electrolyser and ammonia plant could be sized downwards, to supply ammonia for dry year generation only. This could negate the need for a port facility and allow inland locations to be considered. Alternatively, the ammonia could be used to generate electricity more regularly than for non-dry year peaking duty, to ensure produced ammonia is consumed before storage tanks reach capacity.

BASE CASE DESCRIPTION

As described earlier, due to the rapidly developing nature of hydrogen technology globally, the base case covers a range of building blocks that may make up an eventual optimal solution. Which of these potential elements would ultimately be taken forward as a fully optimised solution, and the best sizing for each, is unknown at this stage.

The hydrogen base case involves the creation of green hydrogen from a 350 MW electrolyser plant. The plant is supplied using off-peak renewable electricity from the national grid, assuming enough is available to support a capacity factor of 60%. The resulting compressed green hydrogen gas (H_2) is either stored in buffer storage vessels or fed directly into the ammonia synthesis plant, where it will be combined with nitrogen (N_2) extracted from the air to produce green ammonia (NH_3). The average annual ammonia production rate is approximately 174 thousand tonnes.

This green ammonia is refrigerated to -33°C to keep it in liquid form and will be stored in this condition in large full containment tanks to a volume of 198 thousand m^3 (equivalent to 135 thousand tonnes). When required for dry years, the stored green ammonia is then cracked back to hydrogen and combusted for power generation through a 100% hydrogen-fuelled CCGT.

BASE CASE OPERATION

During normal years, the hydrogen/ammonia production plant would operate generally using off-peak electricity. Filling the available tanks would take around 9 months. Surplus green ammonia would then be exported to international markets via regular shipments.

During a dry year, ammonia production and export could be stopped to provide a demand response of 229 MW – the equivalent of a 0.5 TWh NZ Battery over three months. The ammonia cracking plant and 150 MW CCGT power plant would start up and use the stored ammonia to generate an addition 0.29 TWh of electricity over three months. The stored ammonia is enough to run the power plant at full output for this period. Any required generation beyond three months could potentially be provided through imports to top up local storage.

IMPLEMENTATION

There are various options and permutations of possible staged approaches that could be deployed, to mitigate the relative uncertainty of hydrogen technology maturity, and the uncertain development of an international green hydrogen market for export/import. The main options would be:

- Demand response only, to mitigate against maturity risk of ammonia cracking for electricity generation. The hydrogen production could potentially be scaled up to 700 MW electrolyser plant, providing a demand response of 1 TWh over three months
- Generation in New Zealand only to mitigate against the risk of a fully developed international green ammonia market. This could involve scaling down the hydrogen production to meet provide sufficient ammonia to fill the tanks in two years, so that no surplus is created. The available energy benefit could be 0.48 TWh.

During the next project phase, the technical maturity of the required hydrogen plant would need to be further investigated to gain confidence that readiness levels are high enough to proceed with design and construction, particularly related to the Ammonia Cracking plant. In parallel, expressions of interest in international Green Ammonia purchase would need to be explored and off-take agreements negotiated. The outcome of these two key risk items would guide a decision on how to proceed.

COSTS

Hydrogen Total Lifetime Class 4 Cost Estimate			
	Base cost	50th Percentile (P50)	90th Percentile
Total Cost at PV – Excluding Revenue ($M)	Commercial Information		
Total Cost at NPV – Including Revenue			

Revenue included relates to the sale of electricity when generating during the dry year period, plus the sale of green ammonia internationally during a non-dry year.

RISKS AND OPPORTUNITIES

There are a number of risks and opportunities for the NZ Battery Hydrogen solution, which are fully detailed in Appendix G. We would highlight the following:

Opportunities	Risks
Emerging technology could improve implementation of the base case, including better performance than that assumed	Technology will not be sufficiently mature to achieve base case scale requirements by 2030 or will not be sufficiently proven/reliable to perform at the level assumed
Hydrogen battery solution can be developed by exiting market (other commercial organisations)	The plant, once built, becomes obsolete early in its lifetime due to advancing technology
Other technology solutions that would otherwise be turned down in non-dry years could continue supplying power to hydrogen.	Risk of ammonia export not being possible at the expected volume or price. International market is developing and is not yet established. There may be competing exporters of green ammonia closer to demand centres.
Opportunity to develop partnerships with local iwi. Economic and social opportunities for Māori groups and communities.	Risk that commercial renewable power generation does not increase sufficiently to drive the hydrogen battery
Option to also provide short-term load following in addition to dry year back-up supply	The project not meeting requirements of the Resource Management Act and cannot be consented.

RECOMMENDED NEXT STEPS

We understand MBIE will use the content of this Report, plus other workstream outputs to determine what, if any, options to take forward to a further stage of investigation.

Following review of this Report and confirmation by the MBIE NZ Battery Team of their decision with regards to any Advised Option(s), the recommended next steps would be to develop a detailed workplan to proceed with the Phase 2 work. This would be anticipated to include site selection and design development, leading to a detailed engineering design of the chosen solution. This would deepen understanding of costs and capabilities, in order to inform a Cabinet decision on whether to proceed to construction.

Next steps can be further discussed and refined, as required, and we would welcome the opportunity to work with the MBIE NZ Battery Team further on this project.

APPENDICES

A Te Ao Māori Reference Information

B Technology Reference Information – Biomass

C Technology Reference Information – Geothermal

D Technology Reference Information – Hydrogen

E Environmental Reference Information

F Economic Impact Assessments

G Risks and Opportunities Register

H Reference Information – Cost Estimates and Modelling Tools

Glossary

Ammonia cracking	Conversion of liquified ammonia to hydrogen gas
Assessment Attributes	The assessment attributes used to assess the Prospective Options as part of this Feasibility Assessment
Biomass	Organic material containing energy derived from photosynthesis
Biomass generation plant	Combustion chamber, water boiler and steam turbine
Black biomass	Thermally treated material which can take a range of forms from pellet to briquette
Brown hydrogen	Hydrogen produced by splitting water into hydrogen and oxygen using electricity generated from fossil fuels
Dispatchable	Power plant that can ramp up/down electrical output in short-term timeframes (nominally half hour)
Electrolyser	A fuel cell in which a chemical reaction occurs to split water molecules into hydrogen and oxygen
Energy vector	An energy form derived from natural resources that can be converted to enable transportation, storage and use at another location/time
Exotic forest	Usually plantations of non-native tree species
Gas reinjection	Recycling of non-condensable gases back into the geothermal field
Geothermal energy	Utilizes the accessible thermal energy from the Earth's interior. Heat is extracted from geothermal reservoirs using wells or other means.
Green ammonia	Production of ammonia using renewable electricity
Green hydrogen	Hydrogen produced by splitting water into hydrogen and oxygen using renewable electricity
Greenhouse Gas (GHG) neutral	"Condition in which the net GHG emissions associated with an entity product or activity is zero for a defined duration"
Load following	The power plant load governor (controller) is set to automatically adjust to match the load as demanded by the grid within the constraints of safe plant operation
Log yard	Collection point and storage of harvested logs
Low energy periods	Prolonged dry, calm and cloudy periods, known as "dry years"
Mitigation	Action required taken to address risk
NZ Battery Project	MBIE's project to identify physical options for managing, or mitigating, the dry year security-of-supply risk in New Zealand in a 100% renewable system.
Primary Options	Technologies and their sub-options that were shortlisted for the Options Analysis study

Prospective Options	The shortlisted options that were taken through to subsequent phases of the NZ Battery Project
Reinjection	Recycling of fluid extracted from the geothermal field and returned to the field after its energy content has been extracted
Schedulable	Power plant that can turn on/off or ramp up/down electrical output, in longer term timeframes (nominally days to weeks)
Stockpile	Storage of white biomass chips or black torrefied pellets
Sustainable forestry	Managed regenerative forest to enhance biodiversity and protect ecosystems
Technologies	The three main technology areas of Bioenergy, Geothermal Energy, and Hydrogen considered for the NZ Battery Other Technologies Feasibility Study, shortlisted from an original five, which also included Air Storage and Flow Batteries
Technical Overview Group	Team members acting independently to the main technical team providing overview, guidance, challenge and quality reviews
Technical Reference Group	An advisory group established by MBIE to inform the NZ Battery Project, with the role of providing technical expertise and sector knowledge relating to quantitative analysis. Team members act independently to the main technical team, providing overview, guidance, challenge and quality reviews
Torrefaction (torrefy)	A form of pyrolysis (thermal treatment) of biomass
White biomass	Usually woody logs and chips

Abbreviations

AEE	Assessment of Environmental Effects
ASU	Air Separation Units (Cryogenic)
BAU	Business As Usual
BOP	Balance Of Plant
Capex	Capital expenditure
CCS	Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CFB	Circulating Fluid Bed (boiler)
CO_2	Carbon Dioxide
CV	Calorific Value
EMC	Equilibrium Moisture Content
EPC	Engineering, Procurement, and Construction
FID	Financial Investment Decision
GW	Gigawatt
GWh	Gigawatt-hour
GHG	Greenhouse Gas
GT	Gas Turbine
H_2	Hydrogen
HGV	Heavy Goods Vehicle - Logging Truck
IP	Intellectual Property
IRENA	The International Renewable Energy Agency
kW	Kilowatt
kWh	Kilowatt-hour
MBIE	Ministry of Business, Innovation and Employment
MMV	Measuring, Monitoring, and Verification of geothermal wells
MW	Megawatt
MWh	Megawatt-hour
NCG	Non-Condensable Gases
NH_3	Ammonia
NPV	Net Present Value
NTP	Notice to Proceed

NZ	New Zealand
NZ Battery	NZ Battery Project
NZBOTFS	NZ Battery Other Technologies Feasibility Study
NOx & SOx	Nitrous Oxides and Sulfur Oxides (pollutant emissions)
OCGT	Open Cycle Gas Turbine
ORC	Organic Rankine Cycle
O&M	Operation and Maintenance
Opex	Operating Expenditure
PEM	Proton Exchange Membrane (electrolyser)
PPA	Power Purchase Agreement
PV	Present Value
R&D	Research and Development
RMA	Resource Management Act
SNG / Syngas	Synthetic Methane
TW	Terawatt
TWh	Terawatt-hour
VRE	Variable Renewable Energy

1 INTRODUCTION

1.1 BACKGROUND

MBIE is investigating options to manage or mitigate New Zealand's "dry year problem", a feature of the country's highly renewable electricity system. The dry year problem arises when hydro in-flows, and hence generation, become scarce, and a source of back-up generation is needed. In the future, with greater development of variable renewable generation, this may become a dry, calm or cloudy problem. New Zealand's back-up generation is currently provided by fossil fuels, but the NZ Battery Project is wanting to determine the feasibility of renewable energy storage and the flexible generation options that can provide this instead. This would enable a transition away from fossil fuels, to achieve the ambition of a 100% renewable electricity system by 2030.

The NZ Battery Project intends to identify physical options for managing or mitigating supply risk in a 100% renewable system, which includes hydro and non-hydro options. The project is a multi-stage, multi-year process and is currently in Phase 1: Feasibility Study. This phase will end with advice to New Zealand Cabinet in 2022 on which option, or combination of options, should be progressed to Phase 2. This would involve detailed engineering design of the preferred option(s), leading eventually to a final investment decision.

1.2 PURPOSE OF THE OTHER TECHNOLOGIES FEASIBILITY STUDY

The purpose of the Other Technologies Feasibility Study is to investigate the technical, commercial and environmental feasibility of non-hydro solutions to the dry-year problem and characterise their likely social and cultural effects. The goal is to identify the best other technology options for providing large-scale, long-term, renewable energy storage solutions that could be complementary to, or a substitute for, a pumped hydro solution (such as Lake Onslow Pumped Storage, which is being investigated as part of a separate feasibility study).

The Other Technologies Feasibility Study was comprised of two main stages:

The first stage was the Preliminary Feasibility and Applicability Assessment **(Options Analysis)**[2], which focused on the review of non-hydro renewable technologies, to recommend two to three Prospective Options for further study.

Five broad alternative technologies were investigated:

- Bioenergy
- Geothermal Energy
- Hydrogen and other green energy vectors
- Air Storage
- Flow Batteries

[2] 6-P0264-RPT-1001 Options Analysis Report (WSP)

These non-hydro solution technologies (the Primary Options) were generated by the NZ Battery Project Team from a long list of alternative approaches, which were then screened against criteria and targeted external engagement for feedback, in consultation with the Technical Reference Group.

These were then analysed via the Options Analysis process, together with input and collaboration from MBIE, resulting in the recommendation that the following three Prospective Options be considered for further study.

PROSPECTIVE OPTION	DESCRIPTION
Bioenergy	Biomass Production & Storage
Geothermal Energy	Controlled Schedulable Geothermal
Hydrogen	Hydrogen Production with (Liquid Ammonia) Carrier Storage
Air Storage and Flow Batteries were not recommended as Prospective Options.	

The technology options of biomass, geothermal and hydrogen, all met the key criteria of large-scale, long-term and renewable energy, defined as follows:

- **Long-term**: capable of storing or remaining ready to discharge energy (in the case of options such as bioenergy or geothermal that do not store energy in the conventional sense) for at least two years
- **Large-scale**: capable of delivering nominally 1 TWh of electricity supply over a period of three months, with a stretch target of potentially up to 5 TWh
- **Renewable**: deploys a fuel or energy vector that is renewable i.e. one that can replenish itself indefinitely.

Each Prospective Option identified in the Options Analysis had specific engineering and environmental risks and challenges. These included the challenge of assessing an option based on a very early stage of design development and the high level of uncertainty in scope, delivery strategy and the location of any project implementation. Many of these were variable and would be highly dependent on the location of any site work and infrastructure, and other unknowns at this stage. However, each prospective option offered sufficient potential to be considered, as either a stand-alone solution or for deployment as a portfolio of complementary building blocks.

The second stage of the study was the **Feasibility Assessment** tasks. These included technical and commercial feasibility assessments of the Prospective Options, including the viability of integration and deployment by 2030 in the New Zealand Battery context, and assessing the options to inform the determination as to whether any should be developed further (as an Advised Option).

Together, the **Options Analysis** and **Feasibility Assessment** comprise the **NZ Battery Project Other Technologies Feasibility Study.** This Report presents the results of the Feasibility Assessment.

The ultimate outcome of the Other Technologies Feasibility Study is to determine which alternative technology option, or combination of options, should proceed for further investigation as part of a detailed business case, when considered alongside a pumped hydro solution.

1.3 PURPOSE OF THIS REPORT

The aim of the Feasibility Assessment was to develop the Prospective Options in sufficient detail to establish the design basis and system characteristics of each of the options, by building on the work done in the preceding Options Analysis task. This involved more detailed engineering and analysis, plus a broad assessment of the risks and opportunities for each option. Key areas of focus were to develop cost and technical data for the Prospective Options, in terms of scale, complexity, commercial readiness and operating performance. It also considered cultural, social and environmental effects and engineering requirements for project implementation in New Zealand.

This Report forms a summary of the tasks carried out in the second part of the overall Other Technologies Feasibility Study – the **Feasibility Assessment**.

This work included desktop studies, developing concept designs, preparing feasibility-level cost estimates and schedules, assessing technical and commercial risks and recommending next steps for each option.

2 APPROACH

Over the course of the Feasibility Assessment, WSP's New Zealand and international team members, together with MBIE's NZ Battery Project Team (including support from other subject matter specialists), applied a structured process to evaluate each of the Prospective Options.

The assessment approach was aimed at achieving a technology or portfolio of technologies capable of providing **large-scale** (1 TWh over three months, up to a stretch target of 5 TWh, if feasible), **long-term** (stored over years with a recharge period of two years or less), **renewable** energy storage. The options were not generally constrained by the need to identify specific locations, the need to align with any existing NZ energy sector assets or developments (i.e. greenfield basis assumed), or whether the NZ Battery should be centralised into one location or distributed.

The work included sharing drafts of findings for discussion, reviews and feedback, assessment workshops, technical and evaluation challenge sessions to arrive at the recommendations.

The main steps undertaken are summarised below:

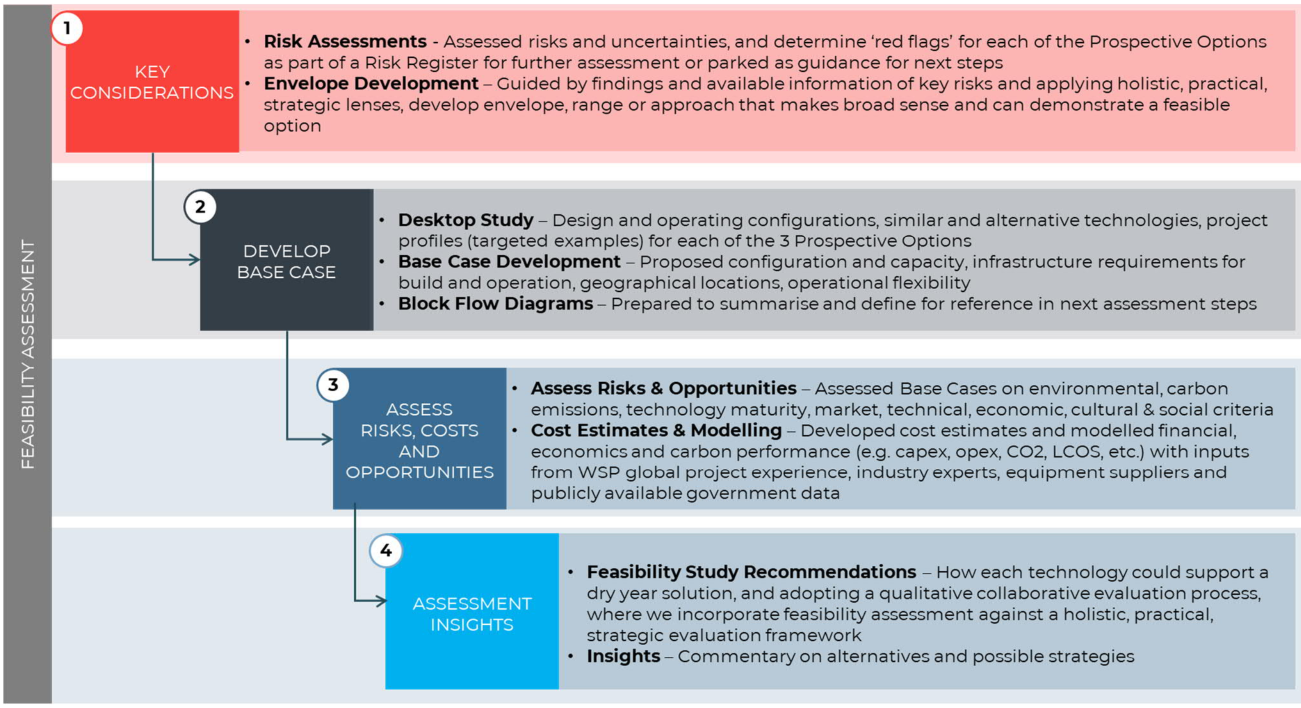


Figure 2-1: An Overview of the Feasibility Assessment Approach (Source: WSP)

Cross-checking and challenge was provided by WSP Technical Overview Group (team members acting independently to the main technical team) to ensure appropriate levels of rigour were applied.

2.1 KEY CONSIDERATIONS

WSP **assessed risks, uncertainties, and potential issues or "red flags"** for each of the Prospective Options, along with some particular areas of focus, identified as recommended for further investigation. These considerations were the aspects specific to each technology that were expected to most critically inform the feasible boundaries for each option. By addressing as early as possible in the process, the impacts of these considerations could then be incorporated (or "baked in") to the technology concept designs up front. A set of key considerations specific to each option were determined in collaboration with MBIE, to ensure the most pertinent issues, risks and constraints were the focus of initial concept development and base case selection for each technology.

These considerations do not represent an exhaustive list of risks. A full assessment of risks (and opportunities) was carried out (refer Appendix G) as part of the further feasibility assessment process, once the feasible envelopes and base cases for each technology were decided.

The Feasible Envelope Analysis process was then carried out, which identified the envelope, range, or approach that made broad sense and could demonstrate a feasible solution, rather than defining a fully optimised engineering solution at this stage.

Following initial assessments, we prepared summaries for each of the three technology options. These informed a Key Risks and Feasible Envelope Workshop, where the team jointly applied various lenses to discussing and developing the primary attributes and defining acceptable boundaries (acknowledging uncertainty, where applicable, of the feasible limits of each technology option). These were then able to be embedded as early as possible in the process and inform the subsequent selection of a base case conceptual system design for each technology

SUMMARY OF TECHNOLOGIES AND KEY CONSIDERATIONS ADDRESSED

TECHOLOGY	KEY CONSIDERATIONS
Biomass	Supply chain (storage, logistical and construction capacity constraints) Greenhouse Gas (GHG) impact of the biomass feedstock Competition for biomass Fuel type (selection and influences)
Geothermal	Sub-surface and well operation feasibility Project execution strategy (what is realistic and practical) Carbon dioxide extraction and reinjection technology development
Hydrogen	Technology maturity International market assessment Safety and environmental risks

2.2 DEVELOPING BASE CASE

Building on the outputs of the above assessments, targeted investigations then took place in the form of further desktop study for each of the technology options. These investigations included discussions with relevant external parties (such as OEMs and local and global entities with related experiences of similar or alternative technologies) and focused on potential design and operating configurations, as well as identifying project examples.

This work was aimed at informing the development and selection of a preliminary conceptual system design, or base case, for each option. Base cases include a summary for each technology, (including the considerations that went into their development), along with generic energy system descriptions and block flow diagrams. They also provide an outline of the proposed configuration, sizes and technology processes across the steps relevant to that technology, including sourcing of energy, extraction, transportation, infrastructure requirements, charging, storage and electricity generation.

Selected potential alternatives were also included as supplementary information in the base case summaries for consideration, such as flexible operating modes or possible variations to technology processes.

2.3 ASSESS RISKS & OPPORTUNITIES

The next step was to use the base cases for each technology as a reference to carry out a wider assessment of risks, costs and opportunities. The aim of this exercise was to understand the broad range of issues that might impact the feasibility of providing dry year security for each option, and allow a full evaluation against other options (including hydro). It also informed cost estimates and schedules.

Risks and opportunities (and the work required to understand and assess these) were identified during Risk Workshops run by the WSP Team. Approximately 55 risks and opportunities were identified for each of the three technologies within the following categories:

- Environmental
- Te Ao Māori
- Social
- Carbon Emissions
- Technology, including maturity, capability, reliability
- Technical, including engineering challenges, hazards and safety
- Market / Economic, including for both fuel and parts and job creation potential.

A Risk and Opportunities Assessment Framework was developed to provide a consistent approach to risk assessment across the technologies. This is provided in Appendix G1 for reference. Ratings for the likelihood of occurrence and for the severity of the consequence were applied to each risk and opportunity. Risk mitigation and opportunity exploitation actions were then identified. The mitigated risks and exploited opportunities were then reassessed to provide a residual threat and opportunity assessment framework, which is described below.

Threat Level	Description of mitigated threat (risks) implication	Opportunity Level	Description of exploited opportunity implication
Extreme Threat	An extreme residual risk rating indicates the implementation of the technology has some uncertainty around its feasibility and this risk threat should be investigated further before proceeding.	Extreme Opportunity	An extreme opportunity is one that should be prioritised for exploitation and further investigation.
High Threat	A high threat residual rating indicates that there is still a significant level of uncertainty with this risk, which is likely related to the base cases not being specific to a site or location. Selection of appropriate sites could lower the threat level.	High Opportunity	An extreme opportunity is one that should be investigated further at the next project stage to confirm exploitation strategy.
Moderate Threat	A moderate threat is one that should be investigated further at future project stages to confirm the risk rating and mitigation.	Moderate Opportunity	A moderate opportunity should be reviewed during the option development project stage to confirm applicability.
Low Threat	Low threats should be reviewed at the next project stage to confirm their risk status.	Low Opportunity	A low opportunity does not likely warrant further attention but should be reviewed periodically to confirm the status.

Risk ratings consider the very early stage of design development (Feasibility) of the options and the high level of uncertainty in scope, delivery strategy and location of any project implementing the technology. Many of the risks are variable, depending on the location of any site work and infrastructure, which is unknown at this stage.

Details of the risk assessment for each technology are provided in the relevant technology section of the report, with the risk assessment registers appended.

2.4 COST ESTIMATES & MODELLING

Feasibility study level cost estimates (to the level of Class 4 estimates, as per the Associate for the advancement of Cost Engineering (AACE) guidelines) were determined from the base cases, with inputs from technical teams, industry/equipment suppliers, and parallel techno-economic modelling outputs, which helped to sensitivity check and inform the estimates.

A Class 4 estimate as per AACE guidelines is suitable for projects that have maturity of project definition deliverables in the range of 1% to 15%. This feasibility study aligns with the lower end of this maturity scale.

The cost estimates are expressed in terms of range from the base estimate to the 90th percentile (P90) estimate for the three technology base cases. The estimates are presented in several formats that include or exclude escalation, discounting and/or revenue from sale of energy. The total cost estimate is presented, at net present value, over the 35-year life of the NZ Battery other technology solution.

The base estimates have been derived using a mix of analogical techniques (comparison to prior project cost data) and equipment factored approaches using supplier quotes on equipment. This led to the creation of a work breakdown structure for each technology appropriate for the limited level of design development. Where rates from historical projects have been used, they have been escalated to Q3 2022. They have also been adjusted to account for the complexity and high resource demand of this project.

The general approach to risk estimation was used which applies contingency as a percentage of each line base cost item and then a funding risk percentage over the full amount including contingency. This approach is considered appropriate for this stage of project development and has been applied consistently across all 3 technologies. The contingency percentages were applied during workshops involving the relevant technical experts and consideration of the identified risks and opportunities.

The percentage contingencies were selected during estimation and risk workshops including technical workstream team members. They have taken into consideration the value of the base sum, the level of uncertainty in the scope of the item, potential risks with costs for the item such as supply prices, and the source of cost data for the item.

The estimates present the cost estimate ranges from base to 90th percentile. Both the 90th (P90) and the 50th (P50) percentile estimate costs are approximations of the P90 and P50. No Monte Carlo modelling was conducted to identify the P90 and P50 by statistical means.

The P90 estimate is obtained by applying funding risk to the P50 estimate. This funding risk amount represents unknown risks that could eventuate influencing the outturn cost and varies across the 3 technologies to reflect the relative uncertainty. The P90 value represents the estimated value that if the project were, theoretically, to be undertaken 100 times, it is estimated to cost less than this value 90 out of 100 times.

The above approach was externally reviewed for completeness and consistency of cost estimating and scheduling approach across the wider NZ Battery Project options (pumped hydro).

2.5 SUMMARY AND ASSESSMENT INSIGHTS

At this stage, WSP collated the various findings, recommendations, and insights with focus on how each option could best support a dry year solution. We also included additional insights, which serve as commentary on alternatives and possible strategies to address common questions or issues, when deploying such technologies.

Guidance on next steps was also provided and a Level 2 schedule for engineering, procurement and construction works up to commissioning stage.

During each of the regular WSP Team progress and review meetings, members of the MBIE Project Team and WSP provided theoretical and technical challenges to the assessments.

Each of the assessments in this report have been peer reviewed internally by WSP.

2.6 GENERAL NOTES AND ASSUMPTIONS

The general notes and assumptions relevant to our evaluation of the Prospective Options are:

- For storage options that source electricity from the national grid (e.g. hydrogen and other green energy vectors, air storage and flow batteries), we have assumed that all electricity supplied to the grid in 2030 is from a renewable energy source, so those storage options are considered renewable. The scope of works for power transmission infrastructure has not included any national transmission grid upgrades or connections that may be required, depending on the location(s) ultimately selected. The boundary is considered to be the high voltage end of unit transformers associated with the NZ Battery plant.

- The primary scope and focus of this project is to solve the long-term, large-scale, dry year issues in New Zealand. Any additional benefit brought by the technology or the specific option that does not fit against the main criteria has been noted, but has not directly formed part of our recommendation process. An example of this secondary benefit is the ability to dispatch in a short-term, load-following manner.

- For the purposes of investigation, we have assumed that all options, in particular those that involve international supply chains, utilise inputs that are sourced using ethical, non-corrupt, transparent, and sustainable practices with green financing, while meeting anti-slavery, human rights and other moral and ethical requirements.

- This study has not considered specific locations for plant or issues of logistically aggregating/distributing resources e.g. a centralised energy “hub” vs distributed across multiple sites.

- Technology options in this assessment may face significant implementation challenges affecting the feasibility of them being procured, fabricated, delivered and constructed by 2030. We have been cautious to not eliminate options based on an inability for them to be implemented by 2030. We have assumed that costs related to supply chain logistics, shipping, transportation are based on a 2019 business as usual scenario (i.e. pre-COVID conditions and constraints).

- This report has been prepared with contributions from multiple authors, involving different technical, commercial, environmental and advisory team inputs and, as such, is presented as a compilation of various technical and assessment sections.

- The feasibility assessment has covered only practical application aspects of technology options. It has not included the financial/ownership structures through which these options could be implemented.

TE AO MĀORI

3 TE AO MĀORI

WSP recognises the critical importance of Te Ao Māori Worldview in the analysis of each technology. This is discussed both as key considerations within the geothermal, biomass and hydrogen technology analyses, and summarised in this section.

The success of any technology is strongly dependent on the development of an effective Treaty-based iwi engagement strategy. Each of the technologies has a range of economic and cultural opportunities for Māori. Iwi are also significant forestry landowners, have major geothermal resources located on their lands and emerging interests in hydrogen technology.

Iwi / Māori Worldview

In considering the production process for each technology, an iwi/Māori epistemological framework provides the basis upon which the interrelationship between iwi, hāpu and natural resources are understood. This framework provides a deeper understanding of the relationship between iwi and the natural world, connected through whakapapa and tikanga and understood within kaupapa Māori values and Mātauranga Māori knowledge systems.

This perspective allows a culturally-based assessment of how natural resources or taonga (soil, air, water, flora and fauna) are used, and impacted by, each technology.

Te Tiriti o Waitangi Considerations

At the heart of the Crown–Iwi relationship is Te Tiriti o Waitangi and this analysis considers the implications of Te Tiriti o Waitangi on the energy generation processes, in line with relevant findings of the Waitangi Tribunal (the “Treaty Principles”) and the Court of Appeal (the “Principles”).

We have considered the impact and relevance of statutory acknowledgements and commercial redress mechanisms when determining whether the production process for each technology will undermine or enhance commercial redress provisions. We have also considered how the statutory acknowledgements for each settlement are provided for within each technology implementation.

3.1 OVERVIEW OF RISKS & OPPORTUNITIES

This analysis has identified a range of risks and opportunities for each technology type, aligned to the following key themes:

Opportunities

Each technology provides a range of opportunities for iwi, hapu and Māori communities. At a macro-economic level, these comprise:

- Local job creation
  - Construction of stockpile, processing plant and generation plant and associated infrastructure
  - Operation of a new industrial/power facility. Supply chain jobs in harvesting, transportation, and processing.
- Partnerships with local iwi to develop the Battery project
- Economic and social opportunities for Māori groups and communities.

Each technology has discrete opportunity characteristics for Iwi, hapu and Māori communities, including:

- The economic benefits associated with biomass supply partnerships and agreements with local iwi who own and/or operate forestry
- The use of low-value timber as the fuel for a biomass solution can add further value to iwi commercial forestry returns (circa $21-29m), thereby contributing to iwi economic growth
- Opportunity to leverage existing iwi leadership in the geothermal sector
- Potential to utilise Māori geothermal resources to produce green hydrogen for use in iwi-owned business enterprises, and its potential exportation.

Risks

Each technology provides a range of risks for iwi, hapu and Māori communities. At a macro-economic level, these comprise:

- The use of natural resources (taonga) in the process negatively impacts Te Ao Māori
- Negative impacts of operational processes and construction on Māori communities
- A lack of partnership with iwi in developing each technology
- The project having negative impacts on Te Ao Māori, preventing the project being consented/ implemented and harming relationships with iwi.

Each technology has discrete risk characteristics, including:

- The impacts on water, its usage and allocation for the generation of hydrogen
- For geothermal, the impact of applying Mauri Model cultural monitoring in the assessment of sustainable resource management
- Environmental effects from the biomass process compromising Iwi Environmental Management Plan standards.

Detailed overviews for each technology are provided in Appendix A of this Report.

BIOMASS

4 BIOMASS

In this section, we consider and assess the potential to supply large-scale, long-term energy storage and generation flexibility by using biomass in the NZ Battery Project context.

4.1 INTRODUCTION TO THE SOLUTION

Our previous Options Analysis showed that New Zealand currently has a primary supply of biomass through its long-rotation exotic forestry. This can meet the large-scale requirements of this project, both in terms of the large quantities of harvest and flexibility in the timing of extraction. This provides a NZ Battery solution that is self-reliant and not dependent on imported material. Woody biomass resource is currently commercially contracted, so access would be on a negotiated basis, to either access a portion of the contracted resource, or support scaling up of the resource to increase supply.

A requirement to harvest large quantities of woody biomass within a short timeframe has logistical implications. Storage options are likely to be available, but feasible storage lengths will vary based on the form of biomass (i.e. logs, chips or torrefied) and could require cyclical stockpile release and replenishment. Establishing an optimum balance between harvest, storage and pre-processing times is key to the success of this biomass energy storage solution.

New Zealand has a large amount of sustainable forestry biomass available, and a biomass solution creates job opportunities in the rural energy supply chain required for dry year generation.

Biomass energy may be considered to be renewable and greenhouse gas neutral over the long term.

New Zealand's sustainably managed exotic forests may be considered to offer a Greenhouse Gas (GHG)-neutral and fully renewable energy source. A sustainably managed forest ensures that new plantings occur at the same rate as mature trees are harvested, and so the total carbon sequestered in the forest remains unchanged in the long term.

Mature technology options exist to combust biomass and generate the dry year energy needs and have been proven across several reference projects. Mature technology is also available to achieve both harvest and processing of fuel and good practices for minimisation of forest residues exist. The use of solid biomass from pine logs as a fuel, within a Rankine cycle power generation technology, offers a high level of technological maturity, through a proven technology and processing methodology.

This section will examine the practicalities and risks of developing a solution that is based on debarked pine logs, with subsequent chipping or torrefaction processes to meet New Zealand's dry year power generation requirements. These are dependent on:

- Level of large-scale sustainable production of exotic softwood *(pinus radiata)* logs
- Infrastructure for harvest, pre-processing and transport
- Long-term storage of the woody biomass

- Technologies capable of generating utility-scale power from this fuel type.

4.2 KEY CONSIDERATIONS

A number of key considerations were identified for initial investigation, to determine feasibility boundaries and base case selection.

A biomass NZ Battery solution will require a fuel supply and plant. The capacity of the supply chain and the plant will determine the magnitude of the dry year event that can be accommodated. Wider supply chain factors (e.g. stockpile management) will determine the solution's ability to meet sequential dry year power requirements and its level of resilience to this risk.

The considerations that potentially impact the feasibility of the solution are discussed in detail below.

4.2.1 BIOMASS SUPPLY CHAIN CAPACITY AND LOGISTICS

AVAILABLE BIOMASS

A key consideration for a biomass solution is whether a practical and large supply of biomass fuel (logs from exotic forestry) can be made available for a NZ Battery solution. New Zealand has a small number of regions where significantly large volumes of exotic biomass are grown in sustainably managed forests within a reasonable supply radius i.e. avoiding the capacity constraints and cost implications of long distance transport. These areas are Central North Island (CNI), East Cape, top of the South Island and the Otago Region. For each region, there are existing biomass transport and logistical capabilities to support the volumes being considered.

It is difficult to establish what volume of logs may be available for a NZ Battery solution from 2030 onwards. To provide the largest amount of dry year cover, the aim would be to maximise the volumes available for storage and subsequent generation, but this needs to be balanced against competing biomass demands and the practicalities of log trucking and storage quantities.

WSP has considered the current volume of logs exported as one potential indicator of what could be available. Forestry owners have confirmed that this is a reasonable assumption, with them not envisaging major problems with market price acquisition of biomass destined for export. It is recognised, however, that if substantial amounts of domestic biomass were diverted from existing uses, this could result in significant disruption to markets.

Biomass sales are negotiated quarterly by forest management companies (effectively a spot market), so it is assumed that an effective upper capacity limit on available logs is set by the current market price and export quantities from key ports. The largest volume of logs exported from New Zealand flows through one port (Port of Tauranga) at a rate of 6m cubic metres per year and the total volume of logs exported out of New Zealand is approximately 12m cubic metres per year (Source: MPI). The export from one port is deemed, for illustration purposes, to be a proxy for the upper limit available from one forestry region.

Chart 4-1 below illustrates the current harvest volume of logs from the largest of New Zealand's exotic forestry areas (CNI) and the quantity of logs exported from one forest within the CNI area, alongside the volume of logs that would be required to support the NZ Battery Project.

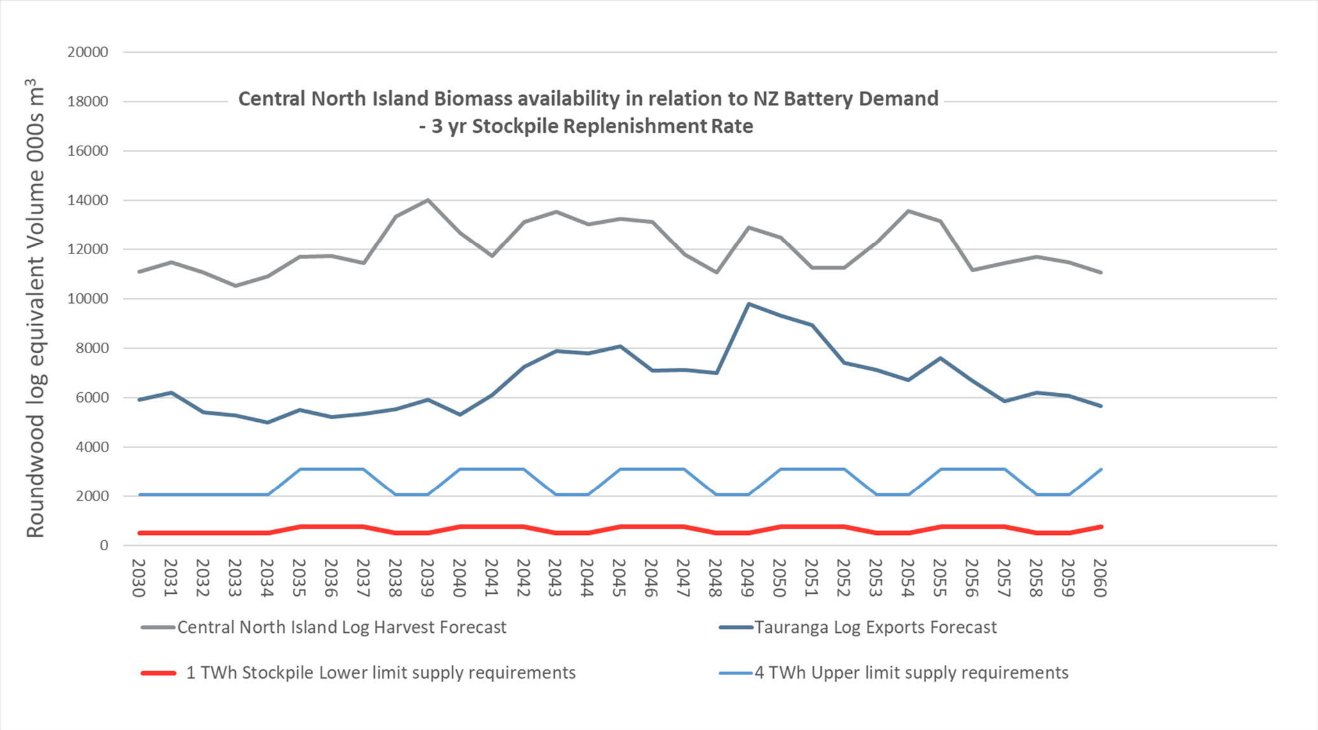


Chart 4-1: Central North Island Log Harvest and Export Volumes

The alternative uses of biomass must also be considered, including the possibility that competing uses (e.g. fossil fuel or other traditional wood-derived products) will lead to either a situation where required log volumes cannot be fulfilled, or become uneconomic due to price inflation in a competitive market.

It is possible that total forest planting on marginal land will increase, however, new planting would not be mature by the 2030 target date for this project. Forest yields (tonnes/Ha) may also increase through future industry advancements. We have assumed that it will be unacceptable to convert food production land to forestry, also that production from any conversion would not mature by 2030. If significant domestic biomass was diverted from existing uses, the impact to the New Zealand industry could be problematic, and result in significant disruption to domestic markets. The usage mix of current exotic forest could also change (e.g. “clear” timber is likely to decrease as a percentage, while pulp market trends are unknown).

LOGISTICAL CONSIDERATIONS

Currently, log harvest, transport and pre-processing are commonly carried out under sub-contract to forest management companies. WSP has investigated the haulage implications of supplying the various orders of magnitude, which are discussed in detail in Appendix B (II). The biomass supply chain requirements for this option have been restricted to working within New Zealand’s currently sustainably managed biomass resource i.e. not requiring any increase in total harvest rate/volume.

The logistical requirements of supplying the Battery will vary, depending on the size and stockpile material selected for the biomass NZ Battery. But, at a minimum, these logistics are likely to require local changes (e.g. in trucking volumes leading directly to plant site/s). There is currently high demand for logging truck drivers, however, the establishment of a moderately steady demand for log supply to a generation plant is likely to support truck driver retention.

Initial calculations show that (for a collection radius of 100km) approximately 3% of the equivalent biomass energy is required for the transport step. This percentage increases in line with transport radius, along with other considerations (e.g. heavy on-road vehicle volumes). Initial calculations led to a general recommendation of targeting a 100km collection radius and a maximum practical transport distance of 200km from harvest in forest to generation site.

Chart 4-2 below illustrates likely levels of truck movement associated with a range of capacities and supply options. The normal year figures are based on a three-year stockpile replenishment period, and the dry year figures represent a two-year period of accelerated restocking (recharging) of the battery.

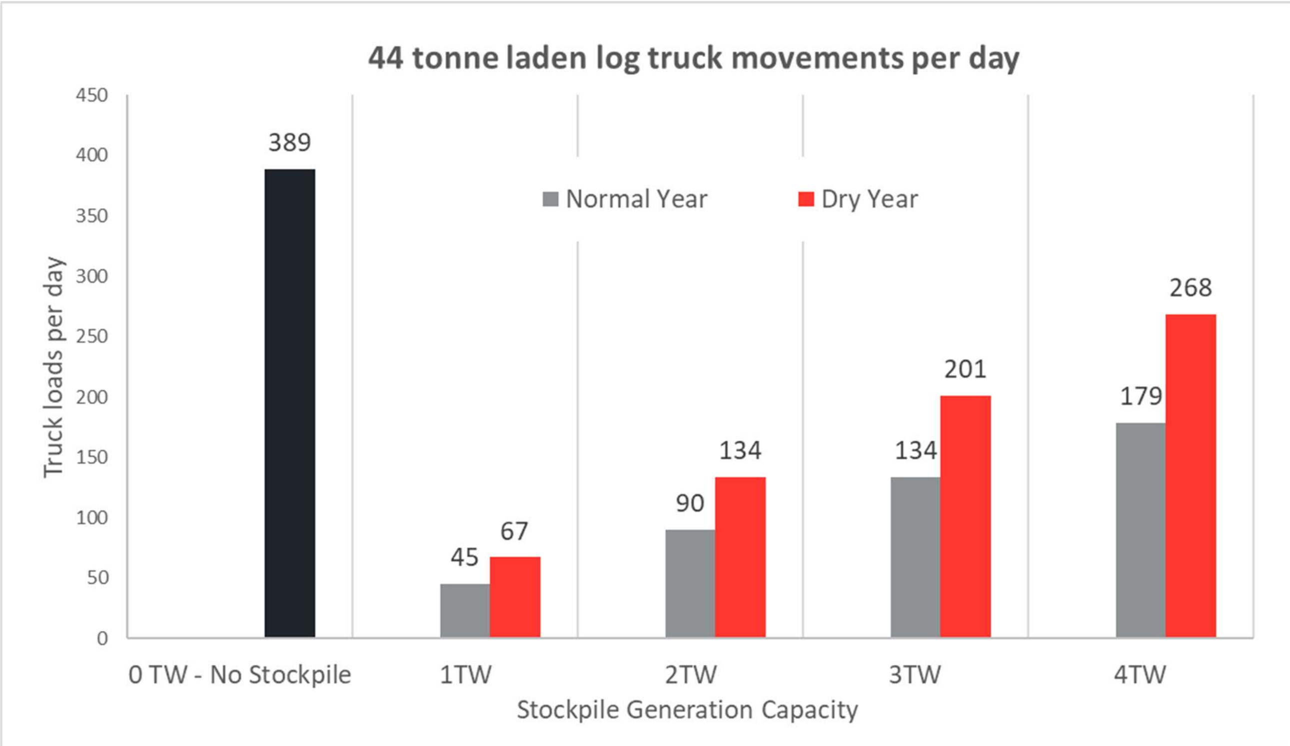


Chart 4-2: Generation scale and the potential truck movements per day

IMPACT ON BASE CASE DEVELOPMENT

Total NZ exotic log harvest is approximately 36,000,000 tonnes pa, with total New Zealand exports of 14,000,000 tonnes p.a. Sufficient logs for a 1 TWh NZ Battery solution is equivalent to approximately 4% of total annual export quantities from New Zealand and 10% of the export quantity from one port. A 4 TWh solution is equivalent to 16% of total exports, and 40% of the export from one port (port comparisons provided for illustration only).

We recommend that the base case is limited to 1 TWh storage solution, equating to a log supply of approximately 560,000 tonnes, as this is felt to best balance the various risks on supply i.e. competing demands on the biomass, the ability of the supply chain to realistically flex for the storage demands and challenges around transport and storage logistics. This isn't considered a hard limit on the biomass supply and an extension above this could be considered.

While the volumes of biomass could be pushed higher than 1 TWh for a given biomass source and generation site, such demands would incur higher risk e.g. competing demands on biomass, as well as more challenging transport and storage logistics.

4.2.2 TE AO MĀORI

There are a range of Te Ao Māori considerations surrounding the biomass Battery option, which can be grouped into Cultural, Spiritual and Social, Commercial and Land Use/Supply Chain themes. These are summarised below, and explored in more detail in Appendix A.

CULTURAL, SPIRITUAL AND SOCIAL ASPECTS

Iwi/Māori continue to maintain strong spiritual and cultural values regarding indigenous ngahere and the impact of any increase in exotic forestry, to the detriment of indigenous forestry, should be considered within this context. There are also significant cultural (e.g. the application of mātauranga and tikanga Māori as it relates to flora and fauna), social (e.g. increased co-operation between hapū), and spiritual enhancement opportunities (e.g. restoration of mauri) that could result from a biomass scheme. It could also increase recognition of indigenous planning e.g. Māori Environmental Management Plans (i.e. CNI Iwi Environmental Management Plan).

COMMERCIAL OPPORTUNITY

Iwi/Māori are the single largest owners of forestry lands, which are leased or to their own commercial forestry companies or to the non-iwi commercial forestry companies. For example, the Central North Island Forests Iwi Collective (CNI), comprising eight of the 27 iwi entities within the Central North Island Region subject area, are the largest owners of plantation forests, controlling 176,000 hectares of forestry lands returned as part of the commercial redress element of the Central North Island Forest Land Settlement Act (2008). A further 11 iwi in the central and east coast of the North Island are, collectively, the largest suppliers of land providing harvesting rights to commercial private entities.

The use of low-value timber as fuel for biomass solutions would add further value to iwi commercial forestry returns (circa $21-29m) and contribute to iwi economic growth. With this in mind, care should be taken to avoid locking into a single geographical area too early. With potential forestry resource supply zones across the country, biomass generation could potentially utilise supply in more than one area. Iwi, as dominant landowners, also have the ability to ensure that economies of scale are achieved to meet the requirements of this scheme.

LAND USE AND SUPPLY CHAIN

With the introduction of a biomass generation scheme, care should be taken to avoid undermining existing commercial redress provisions within Treaty of Waitangi Deeds of Settlement. The scheme would also need to align with Treaty of Waitangi Principles, as defined in the 1991 RMA (Section 6,7,8) relating to environmental impacts on taonga. The four stages of biomass production will potentially produce environmental effects on taonga (being Air, Water, Land). These effects are currently managed through a range of legislative mechanisms, standards and national policy statements, including the RMA 1991 and the National Environmental Standards for Plantation Forestry.

The Crown issues termination notices to the Crown Forest Rental License Holder(s), with the termination period being a maximum of 35 years. For example, in the central and east coast of the North Island, on average, the 27 iwi identified in this area have 20 years remaining on the current lease, at which time they may extend or terminate the license. This will open up the option for iwi to change land use. This does present a risk, however, given the level of iwi investment in the forestry sector, stable lease returns and long-term timber prices, but we see this as low.

IMPACT ON THE BASE CASE

The proposed biomass Battery option aligns with, and implements, the objectives of the Ministry for the Environments Aotearoa/NZ Emissions Reduction Plan for Empowering Māori as part of the Circular Economy and Bio-Economy. However, this option is dependent upon supply side agreements with iwi and effective iwi engagement, which should ensure that iwi are “at the table” with the Crown to determine how the biomass technology sector is structured and how it functions. Care should be taken to ensure alignment with the relevant Treaty of Waitangi Deeds of Settlements, and iwi/Māori forestry leadership is leveraged in meeting the objectives of the NZ Battery Project.

4.2.3 FUEL TYPE

FUEL SOURCES CONSIDERED

The previous Options Analysis work revealed over 50 possible bioenergy sources. These included crop residues (straw, stover), oil-crops (rape, sunflower), fermentable crops (corn), industrial waste from a range of sources (dunnage to used vegetable oil). Also considered were short rotation coppiced crops and forestry “arisings” (surplus products or salvageable leftover materials), along with imported options (ethanol, its precursor being sugar) and biomass.

Early examination showed that many of the options initially considered did not meet the NZ Battery Project criteria (e.g. using food-producing land for bioenergy fuel production was undesirable). Woody biomass, in the simplest sense, takes two main forms; white biomass (unprocessed e.g. logs, chips or pellets) and black biomass (torrefied forms e.g. pellets or briquettes). Some white biomass sources, such as short rotation coppiced softwood, were not eliminated initially, but further investigation established that there are insufficient quantities of material available, and the coppiced fuel options carried significant risk of competition for agricultural land.

Other options (e.g. ethanol derived from softwood) were noted as having desirable features but were considered to have significant technical/developmental risk and, therefore, not pursued. The risks associated with a dependence on imported materials were considered unacceptably high, eliminating several options.

The option of a woody biomass feedstock based on debarked *pinus radiata* logs, obtained on a spot market and harvested from sustainably managed New Zealand forests, was found to most closely align with NZ Battery Project criteria.

BIOMASS STORAGE MEDIUM


Sembcorp's Wilton 10 biomass power station in the UK.
Source: Teeside Live

The NZ Battery Project requires a long-term storage solution due to the long-term and irregular nature of dry year events. There is considerable flexibility in time of harvest for exotic forest, so it would theoretically be possible to harvest logs at the time when dry year generation is needed. This effectively uses the forest as storage, but places very heavy and unpredictable demands on the supply chain logistics of harvesting and transporting biomass. As an indication, this would require 1.1m tonnes of biomass to be provided within a three-month period, requiring close to 400 truck[3] movements per day.

Biomass is a biogenic substance and, once harvested, its durability affects the length of time it can be stored and then fed into a generation plant efficiently. Biomass can be stored as logs, chipped, ground (sawdust), pelletised (white pellets) or torrefied (thermally treated). Other options, such as storage of gasification/pyrolysis plant outputs were examined in the previous Options Analysis and not carried forward. The storage life of possible biomass formats has, therefore, become a key consideration in the initial selection of a biomass base case.

Storage Duration

Debarked logs, stored off-ground, will dry progressively towards an equilibrium moisture content of about 23% over a period of between one to two years. “Sap-stain” is likely to make logs unsaleable on an export market within several months of harvest. The effects of biological degradation (fungal and insect-originated) suggests a safe storage lifetime of around two years, with a slightly higher risk storage lifetime of around three years being feasible.

The logs proposed are commonly debarked at present, given that bark is a major source of contaminants (e.g. mud etc). From a combustion perspective, debarking provides a fuel that is relatively clean and of a consistent quality.

Power plant owners with experience in using torrefied biomass have recommended a storage time of no more than three years, however, a longer storage time may also be feasible as the deterioration from years three to five is primarily limited to physical degradation (as the material falls apart into dust, creating both handling difficulties and explosion risks). The torrefaction process

[3] Based on standard 44 tonne highway truck

uses energy in the process (parasitic energy) so requires a larger volume (approximately 36% additional) of logs for the same generation output.

The rate of deterioration of torrefied biomass is highly dependent on the particular torrefaction process used (which is not standardised). Less stringent torrefaction processes (i.e. lower temperatures) use less parasitic energy, but the product is less biologically stable and may be more difficult to store. More stringent ("harder" or higher temperature) torrefaction processes use more parasitic energy but generate product that has higher long-term stability. Processes such as "steam exploded" pellets are similar to torrefied pellets and may have some properties that are superior, however, examples of longer term storage are limited.

STOCKPILE CONSIDERATIONS

Given that the duration between dry years is not fixed or known, the ability to rotate or replenish a stockpile is needed, as and when biomass becomes unsuitable for power generation. The durability of the biomass ultimately sets the replenishment rate[4], for example at two years, requiring a minimum 50% annual stockpile replenishment rate and a five-year durability requiring a 20% annual stockpile replenishment rate.

While a higher durability material involves a lower regular stockpile replenishment rate, it does lead to the requirement for a larger step increase in stockpile replenishment rates following a dry year. For example, a two-year replenishment rate would not need to increase following a dry year to achieve a two-year recharge period (and would require double the replenishment rate to recharge in one year). At the other extreme, for a five-year replenishment period, the stock replenishment rate would need to increase by two and a half times to achieve a two-year recharge period (and almost four times to achieve a one-year period), which is illustrated in Table 4-1.

Table 4-1: Biomass Logistics Options

BIOMASS Supply options 1TWh[5] capacity	Scenario 1 No Log Stockpile	Scenario 2 Logs in Stockpile 2 Yrs	Scenario 3 Logs in Stockpile 3 Yrs	Scenario 4 Torrefied Pellets in Stockpile 5 Yrs
Replenishment (turnover of battery stockpile)				
Replenishment period years	N/A	2	3	5
Replenishment rate equivalent (TWh(e))	N/A	0.50	0.33	0.20
Process parasitic losses %	1	1	1	36
Replenishment material required (TWh(e)/yr)	1 as required	0.51	0.34	0.27
Approx. raw biomass replenishment material required (Tonnes/yr)	1,100,000	560,000	370,000	350,000

[4] For the purpose of the feasibility study base case selection, the following terms are used:

- Replenishment period = time period to turn over stockpile due to material storage life
- Recharge period = time period to rebuild the stockpile following a dry year (assumed to be two years for all cases).

[5] Biomass supply has been represented in this table for indicative purposes as the equivalent generation output the logs would supply over a three-month dry year period

BIOMASS Supply options 1TWh[5] capacity	Scenario 1 No Log Stockpile	Scenario 2 Logs in Stockpile 2 Yrs	Scenario 3 Logs in Stockpile 3 Yrs	Scenario 4 Torrefied Pellets in Stockpile 5 Yrs
Recharge (battery restock following a dry year)				
Percentage of normal replenishment rate (one year recharge) %	Commercial Information			
Percentage of normal replenishment rate (two-year recharge) %				
Post dry year 'top up' options				
Supply chain risk				

The options for variations in stockpile replenishment rate are a key consideration, as this rate will impact the risks of achieving a resilient system via dependable biomass purchase agreements and reliable long-term supply chain contracts. From a biomass supply perspective, having a more constant supply rate with less variability is considered achievable with local commercial arrangements, reducing supply risk. However, this leads to the negative outcomes of potentially "wasted" biomass logs (if dry years are spread out) and higher stock replenishment costs. By contrast, "just in time" stockpile replenishment rates could require regional/national commercial arrangements and carry more risk, but reduce the potential for wasted biomass.

In any scenario, on-sale options for stockpile turnover may exist (i.e. stockpile end-of-life discards), but the nature of such markets has not been established. Irregular supply and potential quality degradation will likely diminish saleability, however, torrefaction may be one mitigation to open up a wider market to on-sell stockpile discards.

Table 4-2 sets out the opportunities and constraints of the four scenarios described above, including commentary on the related risks of each.

Table 4-2: Biomass storage options based upon 1 TWh (for indicative purposes)

BIOMASS Supply Options 1TWh Capacity	Scenario	Assessment
Scenario 1 Logs – no stockpile	• No stockpile held • Fuel supply chain commences at unpredictable times (perhaps a few weeks' notice) and then supplies the equivalent of 1 TWh of fuel within the three-month generation period.	• Requires chipping before generation – existing and multiple facilities in New Zealand • Based on information obtained to date, risk that forestry management companies not able to supply the envisaged quantities of biomass, on demand, at relatively short notice. Short notice harvesting would also deliver wet biomass (lower GCV) for combustion
Scenario 2 Logs in stockpile Durability: two years	• De-barked log storage • Two-year (log) durability with a 50% replenish rate. • Two-year recharge achieved with no additional demand upon the fuel supply chain.	• Requires chipping before generation – existing and multiple facilities exist in New Zealand • Conservative durability estimation (debarked logs storage) • Results in a steady supply to the stockpile with a two-year recharge • Supply and replenishment rate is higher • Stockpile rotation would be required if dry years are >2 years apart. Use of logs equivalent to 0.5 TWh, either by generation/sale of additional power, or sale to alternative markets • Biomass supply chain risk absorbed by end user via higher Opex costs.
Scenario 3 Logs in stockpile Durability: three years	• De-barked log storage • Three-year (log) durability with a 33% replenish rate • Supply chain demand on logs increases one and a half times to achieve two-year recharge rate.	• Requires chipping before generation – existing and multiple facilities exist in New Zealand • More optimistic durability estimation (debarked log storage) • Lower rate of replenishment • Lower amount of surplus material (equivalent to 33%) to be retired in the case of sequential wet years • Biomass supply chain risk shared between supplier and customer.

BIOMASS Supply Options 1TWh Capacity	Scenario	Assessment
Scenario 4 **Torrefied pellet stock** **Durability: five years**	• Biomass must be torrefied • Five-year (torrefied mass) durability with a 20% replenish rate • Supply chain demand on torrefied biomass needs to increase by two and half times to achieve two-year recharge rate.	• Requires the conversion of white biomass to torrefied biomass – additional facility required that is not currently available in New Zealand • Minimises technical risk for combustion plant due to more consistent standards of fuel stock and ability to use more types of generation plant • Requires 36% additional biomass due to parasitic losses during torrefaction process • Longer fuel durability (potentially optimistic) and hence the lowest rate of stockpile replenishment.

IMPACT ON BASE CASE DEVELOPMENT

The base case takes a balanced approach to the risks associated with the stockpile and associated storage medium. We have opted for Scenario 3 as the base case (a debarked log stockpile requiring a three-year replenishment period). The three-year replenishment period is a shorter duration than the torrefied alternative but involves lower supply chain variability and lower quantity of biomass logs for the same generation output. In addition, it removes the need for torrefaction facilities and the associated introduction of a single point of failure.

The base case scenario assumes a three-year durability of the logs, but we note that the durability of both logs and torrefied biomass has some uncertainty and could result in variations to the scenarios presented. The generation plant selected in our base case (refer Section 4.2.5) can operate on both forms of biomass, so has not played a part in this decision.

Torrefied biomass is still a viable solution for the NZ Battery but, for the purposes of setting a base case, we have not included this step. A risk exists that locking in a fuel type selection too early could create a plant dependent on a technology that may not be practical in the longer term.

4.2.4 GENERATION PLANT TECHNOLOGY

There are a range of generation plant options available for assessment. For large-scale power generation, coal-fired plant is far more common globally than biomass-fired. For a biomass NZ Battery, one option would be to utilise generation plant designed specifically for coal and accept a risk that it may prove challenging to convert biomass to a form with properties sufficiently close to coal, such as torrefied biomass. In taking this approach, it would be necessary to accept the significant parasitic losses that are inevitably incurred to modify (torrefy) biomass to approach coal-like properties (refer Section 4.2.4).

Another option would be to use generation plant that can operate satisfactorily on the wettest and least uniform biomass. A solution within 600 MWe range of generation and achievable fuel consistency would be boiler technologies including Circulating Fluid Bed (CFB) types, which are less common than coal plant but have acceptable technical risk and offer a significant degree of flexibility in fuel specification. It is considered likely that CFB boilers will be able to accommodate fuel flexibility and operate on white biomass chips, torrefied biomass (or other fuels such as biomass pellets) or mixtures of these. Separate fuel storage and feed arrangements would be needed for alternative fuels and may present logistical challenges. Parasitic energy requirements (and associated emissions) would also change and require analysis.

While single coal-fired boilers (ultra-supercritical) supporting up to 600 MWe are known, biomass-fired boilers over 125 MW are far less common. This is not limited by the availability of technology but does suggest that the scale for biomass-fired units will be determined by a unit size for the biomass plant, rather than limited by the spinning reserve requirement (supplementary base generation). High efficiency boiler plant would therefore be recommended (high-subcritical condition).

The operation of the New Zealand grid requires the assignation of spinning reserve equivalent to the largest single generator, and hence the largest single generator is likely to be limited to about 250 MW. This value is, therefore, taken as an upper limit for unit electrical capacity.

IMPACT ON BASE CASE DEVELOPMENT

We have recommended a Circulating Fluid Bed (CFB) boiler plant for our base case solution, to provide flexibility of biomass fuel medium, with individual generation plant units having shaft power up to 250 MW. This targets a total installed generation capacity of approximately 500 MW, providing an additional generation capacity of 1 TWh over three months.

4.2.5 GHG NEUTRALITY AND SUSTAINABILITY

Since the combustion of biomass creates greenhouse gas emissions, there is a risk that a biomass NZ Battery is perceived as not being renewable or GHG neutral. To manage this, the system-wide GHG assessment of the biomass fuel needs to illustrate that emissions from biomass combustion are balanced by the growth of renewed forest biomass over the long term.

Within a sustainably managed forest, mature stands are harvested at the same rate as new stands are planted, so the total inventory of the forest remains unchanged from year to year. Therefore, in terms of actual log demand pattern, any biomass solution (including the option of continuous year-round log harvesting in quantities to meet stockpile replenishment or recharge) does not change the total forest inventory.

In order to illustrate and assess this scenario, a randomly generated dry year model has been created, showing fluctuating total forestry carbon in the system reaching a steady state of total forest carbon before and after harvest. This includes the forest carbon stock and the average annual emissions from the biomass harvested and the decomposition of the non-utilised biomass. This is shown in Chart 4-3.

In a theoretical forest area of 20,000 ha, the forest emissions average to approximately 360 kt of CO_2-e per year to keep the battery stockpiles replenished and restocked. If it is assumed that the supply chain is comprised of sustainably managed forestry, an approximately “neutral” position is illustrated by the annual net emissions (black line) that fluctuates about zero, and the annual net forest carbon stock would sequester approximately 370 kt CO_2-e per year.

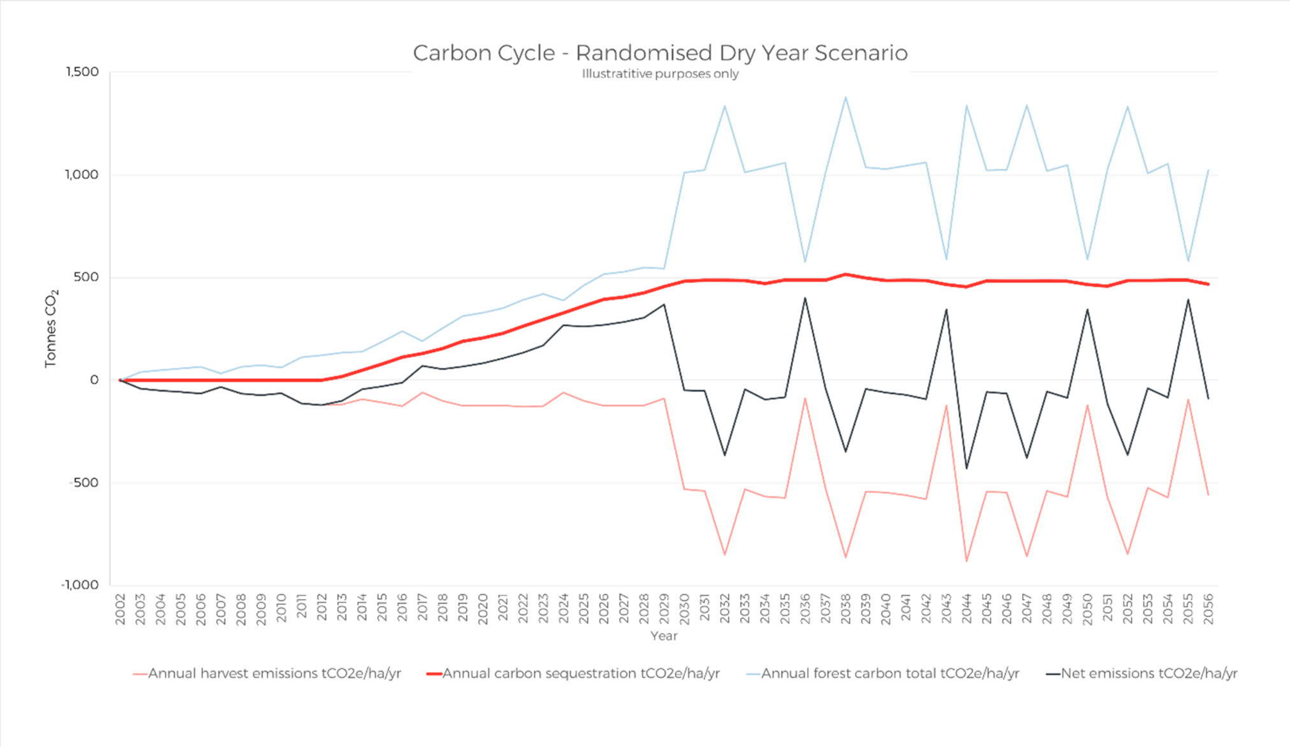


Chart 4-3: Greenhouse Gas Neutrality

While a specific location for the proposed base case generation and stockpile facility has not been determined, the aim of keeping within preferably 100 km of the most distant fuel source ensures that (even if electric haulage does not eventuate by 2030) the total fuel usage for transport and processing of biomass is minimised (and could be off-set by additional forest creation).

With this provision, and over the rotation period of the forest, the complete biomass-sourced power generation system could meet the definition of carbon neutral i.e. a "condition in which the net GHG emissions associated with an entity product or activity is zero for a defined duration" that is proposed for the forthcoming ISO/CD 14068: Greenhouse gas management and climate change management and related activities - Carbon neutrality.

IMPACT ON BASE CASE DEVELOPMENT

Based on the above model of an example randomised dry year scenario, the biomass fuel supply may be considered renewable and carbon neutral in principle, provided all harvested trees are replaced.

In this scenario, the total volume of biomass required across a random series of 20 dry year events is about 26,700 kt. Of this, approximately 87% is used to recharge the battery and 13% to replenish the biomass stockpile. About 19% of the total stockpile reaches end-of-life and is discarded (about 0.3% per year across this timeframe).

Further explanatory material related to the base case is provided in Appendix B (I) - Biomass CO_2-e Assessment.

4.2.6 OTHER CONSIDERATIONS

ENVIRONMENTAL IMPACTS AND CONSENTING

Environmental factors anticipated to be particularly important in determining the development of a biomass NZ Battery include:

- Impacts to flora and fauna as a result of reduced habitat (linked to exotic forestry monoculture and impacts on the viability of foraging routes (e.g. diversity and length)
- Environmental impacts resulting from felling, including visual, noise, increased vehicle movements and an increased percentage of HGVs
- Impacts to air quality from supply chain and logistics
- Use of highly productive agricultural land for forestry and associated risk to market gardening/food production
- Vehicle movements during construction and operation.

IMPACT ON BASE CASE DEVELOPMENT

Strategies to maximise potential positive impacts are encouraged. These include co-design, co-governance/co-management with mana whenua, socio-economic opportunities (especially for local and under-represented groups) and environmental enhancement.

ECONOMIC SCALE

Within the range of options being considered, there is scope for selecting from a series of economically viable options. Economies of scale for the biomass NZ Battery system would favour at least a 0.25 TWh solution, with larger power generation units. The unit size of power generation plant could be as low as 125 MW and, at the upper end, being constrained to those capacities that are acceptable on the basis of grid security could be as large as units up to 250 MW.

A biomass solution offers the potential advantage of being able to feasibly scale up from 1 TWh to 4 TWh. This could be achieved by replicating the system with several separate generation plants and biomass supply chains across New Zealand. There are several locations with concentrations of smaller sustainably managed exotic forest that could support a smaller scale Rankine-cycle generation plant. While this would not provide the same economies of scale associated with a larger site, this option would allow the overall dry year energy benefit to scale up and spread the associated economic benefits across the country.

IMPACT ON BASE CASE DEVELOPMENT

We have recommend setting the base case scale at 1 TWh, aligned to the larger available biomass resource areas in New Zealand. The option to increase the biomass solution by replicating at multiple smaller scale locations to potentially scale up to a total of 4 TWh in aggregate across New Zealand has been retained.

The extension of the NZ Battery base case concept to installations at multiple replicated or similar sites could be considered. If extension sites were linked to a smaller forestry (fuel supply) constraint, there would be some sites where smaller scale solutions could be developed e.g. 125 MW.

OPTIONAL PART-LOAD RUNNING

The design operation mode is continuous generation for the duration of a dry year shortfall period.

For a biomass-fired plant, it could also be possible to run a plant in a normally-warm, two-shift mode, operating mornings and evenings to match peak power demand, retain hydro storage and complement peak output with solar-PV input. Such an operational mode would consume fuel, in addition to that strictly required to support dry year generation shortfall. However, it may have longer term plant maintenance and operation benefits, would assist with any stockpile replenishment required, and possibly provide financial advantages to the NZ Battery asset, depending on the market interaction strategy.

IMPACT ON BASE CASE DEVELOPMENT

The part-load running has not been recommended for the base case, due to financial implications, potential off-setting of other renewable generation, and to minimise unnecessary biomass combustion as part of the solution.

EXISTING GENERATION PLANT

The conversion of one large Rankine cycle coal-fired plant in New Zealand to torrefied biomass is currently being considered. For the remaining life of this plant, this option would avoid the capital and operating costs of a new base case generation plant.

IMPACT ON BASE CASE DEVELOPMENT

We have not recommended use of existing generation in the base case due to the long-term requirement of the NZ Battery solution. Existing plant has a limited remaining life. However, the optional use of existing plant to defer capital costs could offer a staged decision-making approach, which takes into account the remaining work required to clarify final decisions, and the integration of “greenfield” and “brownfield” options.

4.3 BASE CASE

4.3.1 BASE CASE DEVELOPMENT

Of the options identified as feasible, a range of technical factors have contributed to the selection of the base case.

A generation capacity of 1 TWh over three months has been selected as the base case. This capacity was selected for the following reasons:

- To have confidence that there is uncommitted biomass supply capacity available from 2030, based on limiting the proportion of export quantities diverted without incurring unacceptable impacts on existing log markets
- To be able to source biomass from one forestry area (rather than multiple), limiting transportation requirements (for further information, refer Sections 4.2.1 and 4.2.2).

The requirement for NZ Battery renewable energy generation has been set at 4 TWh, however, capital cost, fuel cost and risk are all related to scale, so it is considered reasonable to select a lower base case capacity that meets dry year generation requirements. Noting that extension of the base case is possible, a generation capacity of 1 TWh over three months has been selected as the base case, to investigate feasibility of the solution.

A greater generation level could be achieved and considered in an approach for implementation. This may involve the use of more than one forestry region, for example, and using more than one generation plant (see Section 4.3.9).

The base case stores biomass in a stockpile in sufficient quantities to fuel the generation plant and provide 1 TWh over three months. We have selected the storage medium of de-barked logs with a three year replenishment period, for the following reasons:

- Represents a balanced approach to managing supply chain variability against risk of wasted logs, avoiding significant increases in volumes of biomass supply following a dry year, providing a more stable biomass delivery profile (albeit still with step increases to replenish following a dry year), but reducing the degree of potential log wastage
- Avoids the need for additional facilities for torrefaction and associated single point of failure
- Minimises the quantities of logs required to achieve the generation capacity, by avoiding parasitic loads associated with torrefaction (see Section 4.2.4).

While a biomass base case has been selected as the basis for costing and evaluation within this report, considerable further analysis is required before a final selection between the two fuel types can be made (i.e. white or black biomass) The option of using torrefaction is discussed later in this report (see Section 4.3.9).

The 1 TWh generation capacity is provided by a 500 MW generation plant. The base case envisages CFB boiler plant to provide flexibility to accept various biomass fuel mediums. The largest single generation is limited to 250 MW, resulting in two or more generation units.

4.3.2 BASE CASE DESCRIPTION

The wood chip and torrefied pellet process options are shown in Figure 4-1. These are the two options considered for the biomass base case.

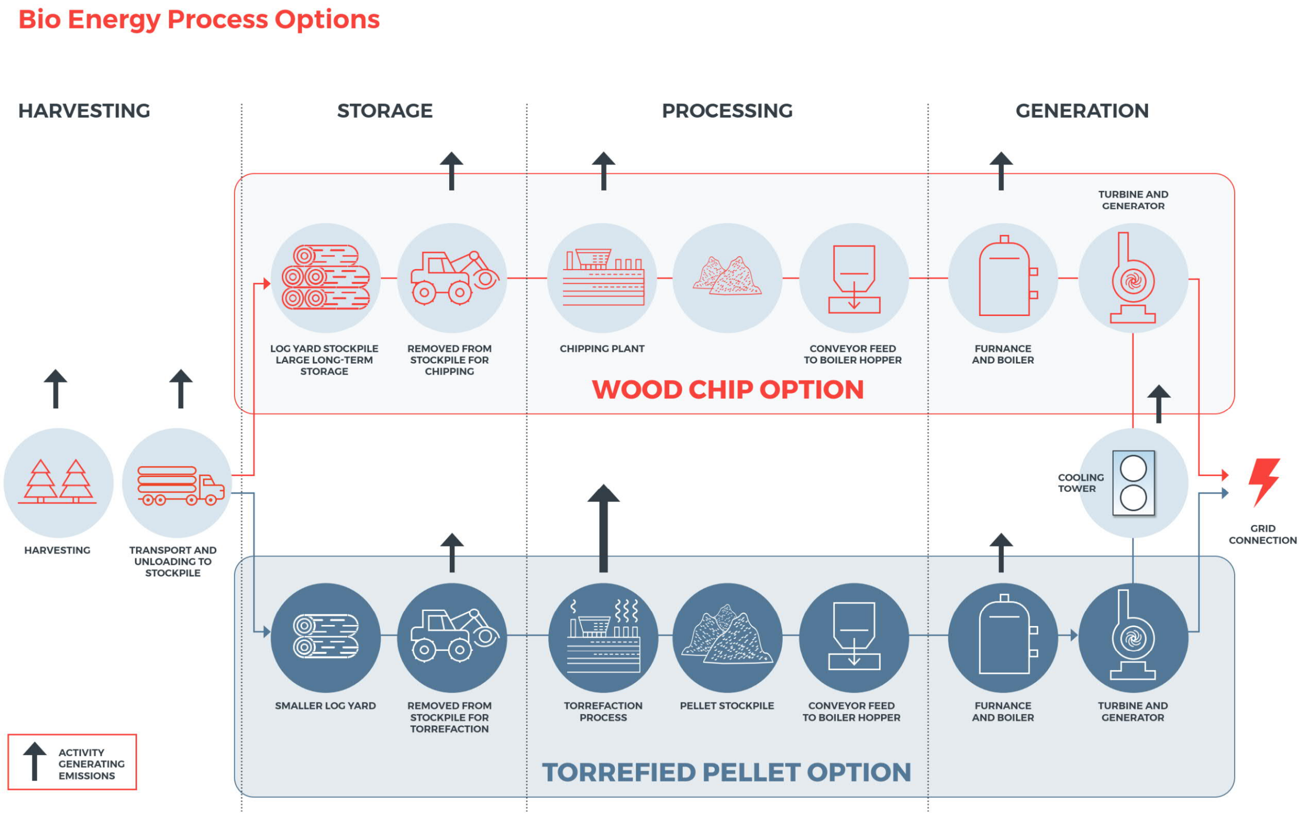


Figure 4-1: Process Options

The proposed base case scenario relies on the established *pinus radiata* forestry practices within large current exotic forest areas, from harvesting to storage in a log yard for processing. The biomass resources are currently sold on an open market and would need to be accessed on a commercial basis. The exotic softwood, as with all biomass sustainably harvested, is essentially GHG neutral (i.e. replanting what is harvested).

The base case stores de-barked logs in a stockpile, sized to allow 1 TWh of generation, which are chipped prior to combustion through a Rankine Cycle power plant for power generation.

The base case has currently been set at 1 TWh of generation, based on our assessment of the supply chain information gathered to date and what is deemed realistic, with potential risks considered. 1 TWh equates to a likely supply radius for logs of 70 km, resulting in more reasonable truck movements and associated carbon emissions, and limits disruption of competing/existing demands on supply. However, an extension up to between 2 TWh and 4 TWh can also be considered. An initial comparison of supply chain requirements for the base case and extension options is provided in Appendix B(II) of this Report.

4.3.3 BASE CASE KEY PARAMETERS

Key parameters for the base case are summarised in the following table:

	BIOMASS SUPPLY OPTIONS 1 TWH[6] CAPACITY	BASE CASE LOGS IN STOCKPILE 3 YEARS	UNITS
Biomass Source			
	Stockpile volume of logs (white biomass) equivalent to about 1 TWh of generation, with an assumed durability of three years	1.1	tonnes
	Log yard and storage area	60	ha
	Harvest radius	100	km
Replenishment (turnover of battery stockpile)			
	Replenishment period years (based on assumed log durability)	3	yrs
	Replenishment rate equivalent	0.33	TWh(e)
	Process parasitic losses	1	%
	Replenishment material required	0.34	TWh(e)/yr
	Approx. raw biomass replenishment material required	370,000	Tonnes logs / year
Recharge (battery restock following a dry year)			
	A post-dry year stockpile recharge rate, allowing recharge over two years	560,000	tonnes logs / year
	Percentage increase of normal replenishment rate, allowing recharge over two years	155	%
	Percentage increase of normal replenishment rate, allowing recharge over 1 year	309	%
Processing and Generation			
	Moisture content (approx.)	40[7]	%
	Chipping plant capacity (approx.)	10,000	tonnes chips / day
	Generation Plant Nameplate	500	MW

[6] Biomass supply has been represented in this table for indicative purposes as the equivalent generation output the logs would supply over a three month dry year period

[7] Softwood such as pine has a moisture content close to 50% at the time of harvest and will reach an equilibrium moisture content (EMC) of about 24% via air drying. Moisture is lost rapidly from wood in the initial period following harvest, pre-treatment and transport, and more slowly as the moisture content approaches the EMC. The rate of moisture loss is influenced (increased) by debarking, stockpile airflow and (provided logs are stored off-ground) is minimally affected by rain. A moisture content of 40% has been assumed noting that the stockpile can be expected to include logs that have been stored for a range of durations up to 3 years, and that the intervals between dry year generation events are variable

	BIOMASS SUPPLY OPTIONS 1 TWH[6] CAPACITY	BASE CASE LOGS IN STOCKPILE 3 YEARS	UNITS
	Additional generation from available stockpile in 3 months for dry year cover	1	TWh
	Potential generation from stockpile turnover in non-dry year	0.33	TWh / year

4.3.4 BASE CASE OPERATION

DRY YEAR RUNNING

Once a dry year generation requirement is identified, the 500 MW generation facility is expected to operate at base load for a duration of about three months supplying 1 TWh of power generation. The chipping plant will be run as required to maintain the steady supply and the whole log pile will be used up.

Following a dry year event, the stockpile will be exhausted, and the steady biomass replenishment rate must be increased, in order to recharge the stockpile within the target recharge period of two years. The project must consider the risks and potential actions, should a dry year event occur at less than a two-year interval. These could include extra-ordinary measures to recharge the stockpile (and associated forest management issues) or reduce capacity to support a dry year generation shortfall.

NON-DRY YEAR RUNNING

During Non-Dry years the stockpile will be replenished at a steady rate to maintain the logs within their 3 year assumed usable life. This would not be required should there be a dry year within the assumed 3 year storage time. In the case where stockpile rotation is required this will be used to generate additional power or drive other revenue-generating activity (e.g. supplied to a torrefaction plant). The value of generation from retired stockpile material, or sales to other markets, can be expected to substantially off-set the cost of purchase of the biomass required for stockpile turnover.

LONGER-DURATION RUNNING

The dry year run duration figure (three months) is a guideline only and it is unlikely that any constraint other than fuel availability would constrain run duration, and hence a 500 MW plant could potentially generate up to 4 TWh in a year, if arrangements were agreed for the biomass supply chain to be expanded.

OUTAGE PRESERVATION

Requirements for the safe preservation of a non-generating Rankine-cycle plant can be categorised according to the duration of stoppage and these include:

- *Plant preservation.* The necessity for preservation of non-operational units to be a significant feature of unit design/selection. Features not required for a base-load unit will be required for units designed for two-shifting or intermittent operation
- *Short duration.* For short duration (a few hours) cessation of generation, gas-side dampers are commonly used to reduce the boiler cool-down rate, and turbines are rotated slowly (barring).

Re-ignition, re-starting turbines when steam pressure rises and return to Maximum Continuous Rating (MCR) may be possible within about one hour.

- *Maintenance outage*. For outages of longer duration (<2 to 3 weeks), the common process would include hot blow-down of steam side, then drying-out. The unit would then be "cold stored". Space heaters and trace heating would be used, and periodic barring (low-speed rotation) of turbines would be practiced. Lube oil circulation and dewatering would be scheduled. A maintenance outage would require a four-day return to service period that includes preparation and warming of units.

- *Extended outage*. For outages of many months, measures in addition to those used for maintenance outages are likely to include gas-side hot air heaters and air circulation. Combinations of hot air blowing and desiccant usage for the steam side. Desiccant trays would commonly be used in the turbine/generator. Space heaters and trace heating would be used, as well as periodic barring (low-speed rotation) of turbines. Regular exercising of fans, mills, dampers would be undertaken. A programme of checks on electrical and control systems would be required and regular lube oil circulation and dewatering operations would also be used. Return to service would be likely to require 10 days.

For a new Rankine cycle plant, some CFB designs include significant amounts of refractory and, for those designs, additional care will be required, both to achieve good preservation and remain within temperature ramp rates on start-up and load change.

Requirements for safe preservation of biomass, post-harvest treatment plant, is to be finalised once this plant is specified.

4.3.5 INFRASTRUCTURE AND PLANT REQUIREMENTS

BIOMASS SOURCE

Existing forest management companies have the resources to harvest, pre-process (de-limb, de-bark, trim) and transport the required biomass. Transfer of ownership of clean logs can take place at the project's incoming weighbridge. While roading will be required to achieve site access, additional roading is likely to be minimal, with most transport taking place on either private (forest-owner property) or public roads.

GENERATION SITE

De-barked logs arriving on trucks will need to be offloaded and stored. From storage, these are fed onto a conveyor to a chipper. Chips then need to be fed to the boiler day-hoppers for metering into the combustion zone.

Generation infrastructure will be a combination of:

- Civil infrastructure (including a log yard and stockpile)

- Temporary construction infrastructure (i.e. accommodation for workers, workshop and storage facilities, infrastructure for transport and offloading and assembly of large/heavy imported items)

- Generation infrastructure, including water supply

- Support infrastructure e.g. offices and transport

- Power transmission infrastructure (depending on the selected location). The boundary is considered to be the high voltage end of the unit transformers).

GENERATION PLANT

The proposed Rankine cycle generation plant could be expected to include, for each unit:

- Fuel reception (trucks unloaded to stockpile)
- Stockpile (uncovered, but off-ground)
- Stockpile recovery to conveyor
- Fuel handling from stockpile to combustion pre-treatment plant (hourglass or scraper and trough conveyor)
- Fuel resizing (grind/mill/size-grade)
- Auxiliary fuel is likely to be required for start-up
- Fuel feed to boiler
- Boiler, turbine, steam, feed-heating and feedwater systems
- Flue gas clean-up systems and Continuous Emissions Monitoring System (CEMS)
- Alternator
- Control system
- HV, MV and LV electrical systems
- Condenser
- Cooling towers (forced draft) and associated ponds
- Civil works – stockpile, generation plant and personnel facilities
- Structural works – boiler and turbine halls, possibly Electric Overhead Travelling (EOT) crane for log reception
- Water treatment systems (incoming water and discharges)

- Minor facilities, Water Treatment Plant (WTP) consumables, site security, fire-fighting etc.

Siemens SST 3000 Steam Turbine. Source: Siemens Energy

While CFB combustors are assumed for the base case, BFB types are possible. If the combustor is a Bubbling Fluid Bed (BFB) type, there may be a requirement for bed material top-up stock, as well as bed-material disposal. The steam cycle can be nominally expected to require 1% blowdown, and hence the water treatment plant capable of 1% make-up. Water treatment is both an exacting science and a very mature technology. Steam turbine, feed-heating and generation plant are also mature technology and will not differ fundamentally from other Rankine-cycle plant.

Historically, condenser cooling has been supplied by either river water (as for Huntly) or seawater (as for New Plymouth). These options would incur significant consenting issues, so for the purposes of this study it is assumed that either a “dry condenser” (fin-fan) or cooling tower approach would be used. The latter would require make-up water.

Wood such as pine typically has about 0.5% ash content. This ash is entirely suitable for land disposal, however, ash collection (baghouse, bottom-ash) systems will be needed.

4.3.6 GEOGRAPHICAL REQUIREMENTS

Suitable geographical options for plant location are influenced by:

- Proximity to biomass source (or log source)
- Proximity to transmission network and to electrical loads
- Accessibility for construction (including large loads)
- Site suitability for foundational loads and avoidance of natural hazards
- Environmental acceptability
- Avoidance of high value land (dairy, urban)
- Avoidance of land of high cultural/social value.

Figure 4-2 indicates the exotic forestry locations of the four largest areas of high-density forestry - Central North Island (CNI), East Cape, top of the South Island and the Otago Region. A review of both forest and key infrastructure locations indicates that there are multiple sites that meet basic geographical criteria. Further logistical considerations explanatory material relating to the base case is provided detail in Appendix B(II) Biomass Supply Chain Logistics Feasibility.

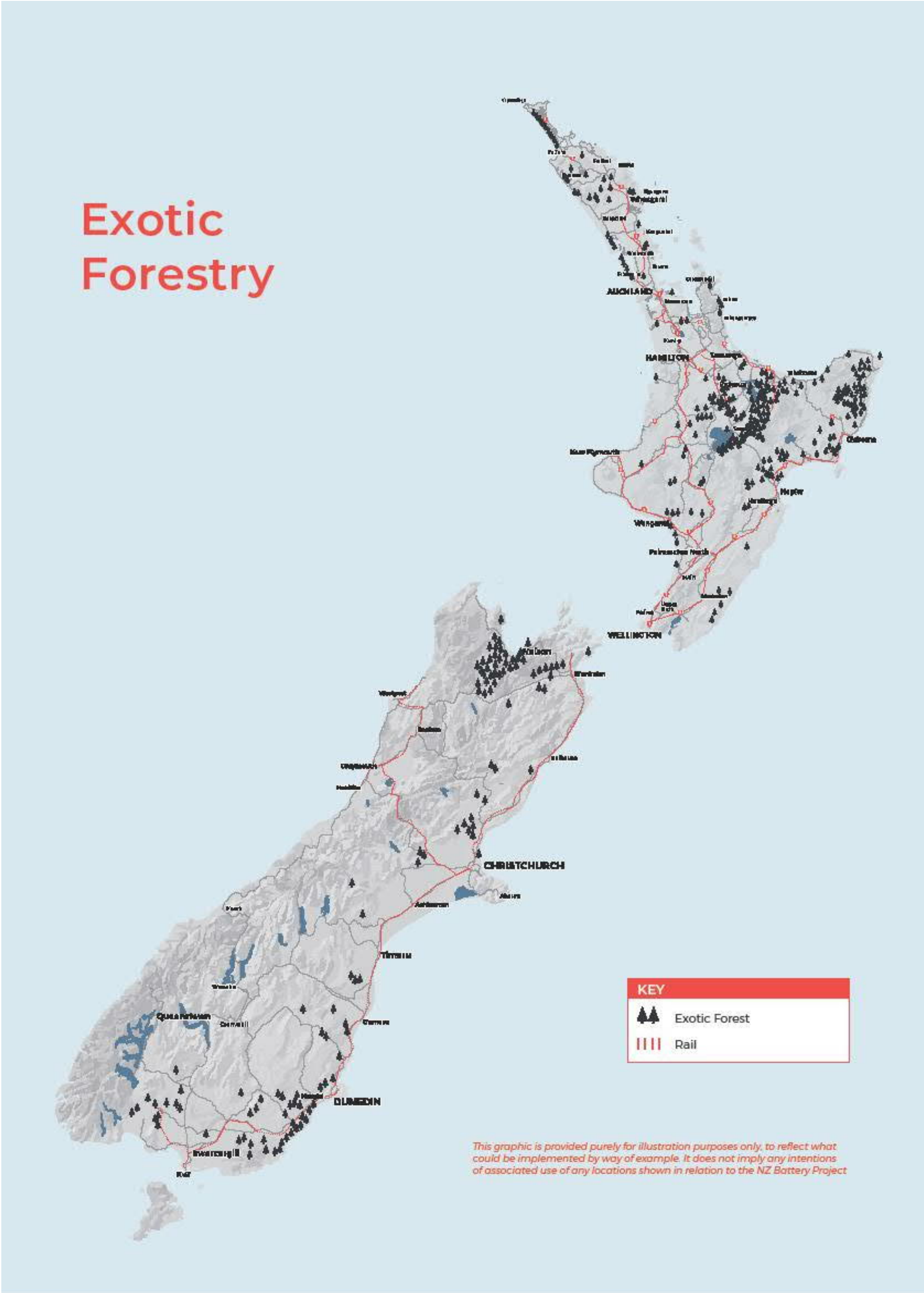


Figure 4-2: Exotic Forestry Locations

4.3.7 CO_2 EMISSIONS AND RESOURCE ASSESSMENT

Based on a high-level assessment of the biomass base case, the total embodied carbon of the construction of the proposed biomass power plant and ancillary equipment is estimated to be 370 kt CO_2-e

As biogenic emissions are eventually reabsorbed by the forest, they are not included in New Zealand carbon accounting rules and IPCC guidelines as net emissions and are considered to be zero in the Energy sector. These are included in the Agriculture, Forestry and Other Land-Use sector of reporting to the IPCC (Intergovernmental Panel on Climate Change IPCC, 2021).

However, if they are included in the study, the forest emissions will differ depending on the annual activities of the supply chain (amount of biomass harvested vs newly planted).

For the base case biomass dry year cycle, the carbon dioxide emissions from transport are estimated to be 14 g CO_2-e/kWh, in terms of the energy generated. Log transport emissions are calculated from the total truck distances travelled per year to feed the stockpile (assuming collection from within a 70 km radius), the truck load (32 tonnes) and its tare weight, the GHG emissions factor for large diesel trucks that has been provided by MfE, and the base case plant generation. Carbon price related to transport and other emissions are implicitly included in the log price.

The land and biodiversity impacts of converting forestry to non-productive land for a timber yard would have a negative impact on carbon sequestration, soil quality and biodiversity habitat, however, the scale of impact for a 60 ha site when compared to the harvesting is insignificant. The harvesting impacts are considered to be minimal, based on the key assumption that the logs are redirected from the existing forestry export supply in New Zealand and harvested from sustainably managed forests. The key environmental impact during the timber harvesting phase is exposing soil to possible erosion.

4.3.8 IMPLEMENTATION APPROACH

The development of a biomass NZ Battery solution will require a staged development and decision process to refine the solution to be implemented. Factors requiring detailed examination also include external influences (e.g. policy, export market and infrastructure strategy). Figure 4-3 provides a high-level representation of a potential biomass solution development pathway.

Figure 4-3: Development Pathways

While a base case has been selected that employs logs and chips as the basis for more detailed scope and cost evaluation, an alternative (torrefaction) solution exists, with insufficient information available to finalise the preferred option at present. However, the proposed high-level development pathway demonstrates that sufficient time is available to test the key assumptions/uncertainties, allowing a final decision to be made. The base case that has been modelled and its alternative are such that selection will not affect the high-level schedule, will have minimal effect on the feasibility-level cost estimates, and no effect on the total assessed project risk.

An early decision on the implementation of a trial of fuel types would be required, to address the uncertainty of the durability of logs as an energy storage option. The trial would require *pinus radiata* logs to be harvested and stored alongside torrefied pellets in controlled conditions and regularly tested for quality and durability. The results of this trial could demonstrate that a torrefaction plant may not need to be incorporated in the biomass battery solution, as proposed.

Alternatively, as discussed, there are external influences that may prompt an early decision, in order to prolong the operational life of existing generation assets. New Zealand does have existing plant that can likely be modified to use biomass (either torrefied or similarly modified). The remnant life of that plant is not known, but even if the remnant life were relatively short compared to the proposed life of new plant, a capex deferral option would be attractive.

WSP has developed a biomass supply chain, storage life and energy conversion calculation spreadsheet model that allows the user to fully adjust all of the major supply chain parameters, storage medium and test sensitivities, which has been shared with MBIE to use as a tool. The tool can be used, together with costs and insights of other factors, to develop an optimised solution that best addresses NZ Battery Project objectives. While material trials are underway, preparations can be made for the selection of generation locations and concept designs, based on the results of this modelling and option refinement.

The process will also involve significant commercial discussions with prospective biomass suppliers (see below), together with extensive stakeholder involvement. In particular, early discussion of Te Ao Māori values with iwi partners, who are both significant forestry landowners and forestry industry management operators. The proposed schedule also allows time for these critical phases to occur.

While timeframes are tight, it would appear possible to schedule the trial and research effort needed to finalise key decisions, without jeopardising the 2030 timeline.

COMMERCIAL AND CONTRACTUAL

The biomass solution is heavily reliant on the establishment of long-term commercial supply chain agreements between the forestry sector and the end user. Further development of this option would require a robust procurement process, to establish long-term security of supply and confidence in the availability of dry year generation on demand.

Aspects to be considered during procurement should include, but are not limited to:

- Ownership entity of the biomass storage, processing and generation assets
- Potential for the incorporation of a dedicated supply chain
- Forestry land ownership and Treaty of Waitangi implications
- Biomass supply chain logistics
- Market price fluctuations
- Demand variability and associated cost risk or escalations. The energy sector is familiar with spot pricing in its market operations and will be familiar with this commercial approach.

4.3.9 ALTERNATIVES TO BASE CASE

BASE CASE EXTENSION AND FLEXIBILITY OPTIONS

A plant capable of 500 MW, operated continuously, would generate approximately 4 TWh per year. 4 TWh, therefore, sets the plant upper limit of generation. Analysis of log exports suggests that the total log supply that is theoretically available would not limit this level of generation, though NZ Battery supply requirements would create significant market effects.

Generation at this level would require transport of logs from a significant distance (incurring additional fuel costs/emissions) and the generation mode would arguably fall outside the definition of a “battery”, as it would be continuous, as opposed to “gap filling”.

The base case plant will be implemented in at least two units. To increase total battery capacity, it would be possible to locate an identical facility close to other large sources of biomass.

Flexibility of operational mode (including partial load and fast response ramp rate) is also a secondary operational benefit and considered desirable by network operators.

DISTRIBUTED UNIT OPTIONS

New Zealand has several locations with concentrations of smaller, sustainably-managed exotic forest. It is likely that at least some of these would offer enough biomass to support a smaller, or small unit sized Rankine-cycle generation plant. While forgoing the economies of scale associated with a larger site, such a proposal would spread economic benefits across multiple communities.

ALTERNATIVE OPPORTUNITY – TORREFIED FUEL USAGE

This option involves the creation of a stockpile of torrefied biomass (from white biomass) designed to offer at least 1 TWh of power during a dry year event. During the remaining lifetime of the units at an existing generation facility, dry year generation could be offered by firing the torrefied biomass within a minimally-modified existing facility. The existing units would be converted to torrefied fuel only (i.e. not used for coal without reinstatement). The existing facility fuel stockpile and logistics would be converted to torrefied biomass, resulting in a significantly reduced storage area. Once the existing units’ lifetime is exhausted, new Rankine cycle plant would be required (either on the current site, or elsewhere).

The risk of dependence by an existing facility on the import of ad-hoc loads of torrefied biomass to achieve recharge rates is considered to be unacceptably high. The alternative option would require the development of one or more major torrefaction plants in New Zealand. Having a higher energy density than white biomass, it would be reasonable to expect that it will be economical to truck torrefied material from a wider radius than considered economical for white biomass options.

While recommended storage for torrefied biomass is about three years, cases of storage for five years have been reported, albeit with some physical deterioration of the fuel. The effectiveness of life extension measures is not known with any certainty, however, minimisation of handling will reduce physical breakdown. On the assumption that a five-year lifetime can be managed, a stockpile designed to allow generation of 1 TWh would require the turnover of a quantity equivalent to 0.2 TWh each year. This could be accomplished, either by burning the material for power generation or selling to a domestic market.

To achieve the guideline two-year recharge rate, the torrefaction plant capacity would need to be at least equivalent to 0.5 TWh per year, which suggests that, for years when recharge is not necessary, the torrefaction plant production must either be turned down, turned off, or its output redirected.

While the conversion of coal-fired boilers to utilise torrefied biomass is considered low risk, the licensing, construction and operation risk of a large-scale torrefaction plant has proven to be problematic in previous conversions and carries a somewhat higher risk. However, the effect of selecting this alternative approach is expected to remain within the uncertainty limits of the base case costing. Trials of one particular type of torrefied fuel (black biomass) are planned by a major NZ generator and the outcome of these trials will inform a final decision regarding the potential suitability of this fuel type.

The schedule for base case implementation allows sufficient time to consider the outcomes of the black biomass trials and confirm the key parameters of white and black biomass durability. This will then allow a final assessment to be made of the technical feasibility of large-scale torrefaction and alternative outlet markets, while still achieving the 2030 project date.

ALTERNATIVE OPPORTUNITY – ETHANOL FROM WHITE BIOMASS

Liquid biofuel derived from exotic forest biomass could also be used to generate electricity. This option envisages the creation of ethanol, using white biomass as feedstock and a Combined Cycle Gas Turbine, or another generator, to produce power to meet dry year shortfall. A liquid fuel would not only allow the selection of more efficient plant (CCGT) but could also take advantage of opportunities to increase the independence of New Zealand's transport fuel options. This option has been assessed to carry significant technical risk.

Ethanol generation includes the following basic steps:

- White biomass size reduction
- White biomass soaking, and with enzymatic hydrolysis
- Transfer and simple sugar fermentation
- Ethanol distillation
- Lignin recovery, with possible usage for parasitic energy supply.

While the generation of ethanol from white biomass is not conceptually complex, it has not been carried out at large scale, and carries significant technical risk.

The creation of ethanol only uses the cellulosic portion of the biomass, however, the lignin portion can be used to supply process heat. The process will have a significant parasitic energy requirement, and we expect would require more raw biomass fuel than the base case selected for evaluation.

Ethanol has a long storage life (years) but requires care to avoid water absorption, or bioactivity (additives are recommended). This option would require the creation of a tank farm, containing the equivalent of 1 TWh of ethanol. Turnover of ethanol, for use as transport fuel extender, offers significant opportunities.

It is possible that ethanol generation could take place in multiple locations. Generation would initially make use of existing OCGT or CCGT plants in New Zealand. When these units reach end-of-life, a new CCGT plant will be required to provide generation.

With a moderately high energy density, ethanol could be economically trucked (as for petrol) and likely storage locations could include exiting tank farm facilities.

The risk of dependence on the importation of ad-hoc loads of ethanol to achieve recharge rates is considered to be too high, and so plant capable of producing the equivalent of 0.5 TWh within New Zealand is required.

4.4 RISKS AND OPPORTUNITIES

A detailed assessment of the risks that are relevant to the selected base case (and alternatives) has been undertaken, as outlined in Section 4.2 and is supplied in Appendix F to this report. For several key risks, specific analyses were undertaken, which are presented in detail in the appendix.

4.4.1 RISK ASSESSMENT SUMMARY

A summary of risks and opportunities for the biomass technology is provided in the tables and descriptions below. The tables show the number of extreme, high, moderate, and low opportunities and risks, before and after treatment/mitigation. Refer to the Risk Register within Appendix G for a detailed analysis of the risks, opportunities, assessment, and mitigation.

Biomass Opportunities		
	Untreated	Exploited
Extreme Opportunities	0	6
High Opportunities	5	8
Moderate Opportunities	9	1
Low Opportunities	1	0
Total	15	15

TECHNOLOGY OPPORTUNITIES

- Opportunities to automate fuel handling, conveyors, cranes etc. **Exploitation**: Requires further design effort and a procurement strategy that will encourage suppliers to develop in this area. **Exploited Opportunity Rating**: High.

MARKET AND ECONOMIC OPPORTUNITIES

- Opportunity for growth of the forestry sector and associated commercial benefits due to the additional demand from the NZ Battery. **Exploitation**: Set up robust procurement contracts, partner with forest owners and stakeholders to develop specific opportunities to grow the fuel-biomass sector. **Exploited Opportunity Rating**: Extreme.

- Opportunity to reuse/repurpose existing generation plants. **Exploitation**: Develop a longer-term strategy to integrate development of NZ Battery with existing generation capabilities and other potential biofuel users. This may include further evaluation and design work on torrefaction plants (some effort outside the scope of the NZ Battery project). **Exploited Opportunity Rating**: High.

- Opportunity to use a torrefaction (black biomass) process to utilise logs at the end of their stockpiled/storage life, as opposed to burning for generation. **Exploitation**: Detailed options assessment to determine potential economic benefits versus environmental impacts and technical risks. Further assessment of torrefaction technology. **Exploited Opportunity Rating**: High.

- Opportunity to use replenishment discarded log stock to feed other log consumers, rather than for generation. **Exploitation**: Investigate of commercial and logistic options for use of logs after assumed storage period. **Exploited Opportunity Rating**: High.

TECHNICAL OPPORTUNITIES

- Opportunity for New Zealand to develop technical expertise and capability in new technologies relevant for decarbonisation. **Exploitation**: For design and construction, contracts need to specify local capabilities, where possible. For operation, the experience gained will be local. **Exploited Opportunity Rating**: High.

- Opportunity to identify improved storage methods that prolong storage life. **Exploitation**: Requires further investigation and potentially trials. **Exploited Opportunity Rating**: High.

- Opportunity to utilise a torrefaction (black biomass) process as an alternative to white chips. **Exploitation**: Assessment of white chip versus torrefaction to be completed, to determine potential economic benefits versus environmental impacts and technical risks. **Exploited Opportunity Rating**: High.

- Opportunity to use existing or new rail lines for transport. **Exploitation**: Consider rail when developing site and project options, consultation with KiwiRail. **Exploited Opportunity Rating**: High.

TE AO MĀORI OPPORTUNITIES

- Opportunity for biomass supply partnerships and agreements with local iwi, who own and/or operate forestry to provide economic benefits. **Exploitation**: Iwi engagement early in project, ensure project aligns with the relevant Deeds of Settlements, leverage off existing iwi/Māori forestry leadership. **Exploited Opportunity Rating**: Extreme.

- Opportunity for local job creation in construction and operation. **Exploitation**: Develop a procurement strategy that values local recruitment and skill development for Māori communities. **Exploited Opportunity Rating**: Extreme.

CULTURAL AND SOCIAL OPPORTUNITIES

- Opportunity for local job creation in construction and operation. **Exploitation**: Develop a procurement strategy and also an operational strategy that values local recruitment and skill development for local and/or New Zealand based resource. **Exploited Opportunity Rating**: Extreme.

Biomass Risks		
	Unmitigated	Mitigated
Extreme threats	26	0
High threats	17	20
Moderate threats	0	21
Low Threat	0	2
Total	**43**	**43**

TECHNOLOGY RISKS

- Risk that low availability of process plant equipment prevents the Battery becoming operational at the required level by 2030. **Mitigation**: Set adequate timeframes and develop appropriate procurement strategies including options for early procurement of long lead equipment and collaborations with main OEMS. **Mitigated Risk Rating**: High.

MARKET AND ECONOMIC RISKS

- Risk of consecutive dry years causing biomass fuel shortage. **Mitigation**: Consider this risk in selection of stockpile size, develop supply contracts with contingency plans, and develop/test a response plan. **Mitigated Risk Rating**: High.
- Risk that low availability of construction materials and resources prevents construction of the required infrastructure by 2030. **Mitigation**: Set adequate timeframes for project development, explore options for early procurement strategy and consider phased implementation of smaller and/or standardised generation units. **Mitigated Risk Rating**: High.

TECHNICAL RISKS

- Risk that the logs deteriorate faster than assumed and handling becomes more challenging. **Mitigation**: Commence a trial of durability and processing options. **Mitigated Risk Rating**: High.
- Risk that ideal sites to develop the Battery project are not available, leading to challenging consenting processes, delays and increased costs. **Mitigation**: Robust site selection process, consider options for standardised/smaller scale solutions, early landowner engagement and partnerships. **Mitigated Risk Rating**: High.

ENVIRONMENTAL RISKS

- Risk that water for generation cannot be supplied to the Battery at the required rate, due to limitations on supply. **Mitigation**: Site selection with sufficient water supply, storage of water, select plant with reduced water usage and early consultation with stakeholders and councils to understand restrictions. **Mitigated Risk Rating**: High.

- Use of torrefaction could increase negative environmental impacts. **Mitigation**: Utilise renewable energy for torrefaction process, detailed options assessment of white chip versus torrefaction, meet air emission standards. **Mitigated Risk Rating**: High.
- Risk that the construction of the generation plant and stockpile has significant environmental impacts. **Mitigation**: Robust site selection process to assess site specific environmental impacts and mitigations. **Mitigated Risk Rating**: High.

TE AO MĀORI RISKS

- Use of water (taonga) in the process negatively impacts Te Ao Māori. **Mitigation**: Establish iwi engagement strategy, apply Mauri Model cultural monitoring in the assessment of sustainable resource management. **Mitigated Risk Rating**: High.

CULTURAL AND SOCIAL RISKS

- Risk that the proposed Battery solution is perceived as not being carbon neutral. **Mitigation**: Provide assurance that large-scale biomass generation is carbon neutral (or better), reference carbon accounting standards. **Mitigated Risk Rating**: High.
- Risk of the biomass battery operation being perceived as highly inefficient and cost ineffective. **Mitigation**: Base case proposed operation to generate power in non-dry years, public engagement strategy. **Mitigated Risk Rating**: High.
- Risk of negative traffic impacts from transportation. **Mitigation**: Robust site selection, use private logging roads, where possible, negotiate road upgrade and safety improvements on public roads. **Mitigated Risk Rating**: High.

HEALTH AND SAFETY RISKS

- Safety risks surrounding log harvesting and handling. **Mitigation**: Procurement and supply contracts to seek opportunities to enhance and emphasise safety. **Mitigated Risk Rating**: High.
- Risks surrounding road safety impacts from transportation of biomass. **Mitigation**: Robust site selection considering transport, use private logging roads, where possible. **Mitigated Risk Rating**: High.

CONSENTING RISKS

- Risk of the project not meeting requirements of the Resource Management Act. **Mitigation**: Robust site selection and careful design of plant to minimise impacts. **Mitigated Risk Rating**: High.

4.5 COSTS

The base case assumes the construction of a single generation facility with a generation capacity of 500 MW, which would be available for dry year generation for a period of three months, with the option to operate for additional periods, if required.

This facility would include a log chipping and processing plant, with the option of torrefaction plant, should it be required, to manage surplus material or extend energy storage capacity.

The solution also assumes the purchase of 60 ha of land adjacent to the generation site and associated log yard plant and equipment to manage the biomass stocks prior to processing for generation.

The Capital and Annual Operational Expenditures (Capex and Opex) for this solution were derived through assessment of the various components, using modelling and reference to existing installations and designs.

4.5.1 COST ESTIMATE

Feasibility Study Level Cost Estimates (Class 4 estimates to AACE guidelines i.e. -30% / +50%). Refer to Section 2. Approach for details of the Cost Estimate approach.

A more detailed breakdown and derivation is provided in Appendix H and cost estimate spreadsheet that accompanies this report.

Table 4-3: Feasibility study level cost estimates (Class 4 estimates to AACE guidelines, i.e. -30% / +50%)

Estimates excluding revenue			
Biomass Total Lifetime Class 4 Cost Estimate (Excluding revenue)			
	Base cost	50th Percentile (approximate)	90th percentile (approximate)
Total Capital Cost (Unescalated)	Commercial Information		
Total Capital Cost (Escalated)			
Total Capital Cost (Escalated at present value)			
Operational costs (2030-2065) Unescalated			
Operational costs (2030-2065) Escalated			
Operational costs (2030-2065) Escalated and at Present Value			
Total Cost (unescalated and not discounted)			
Total Cost (escalated and not discounted)			
Total Cost at PV ($M)			

Estimates including revenue			
Biomass Total Lifetime Class 4 Cost Estimate (Including revenue)			
	Base cost	50th Percentile (approximate)	90th percentile (approximate)
Total Capital Cost (Unescalated)	Commercial Information		
Total Capital Cost (Escalated)			
Total Capital Cost (Escalated at present value)			
Revenue (unescalated and not discounted)			
Revenue (escalated and not discounted)			
Revenue PV			
Total (unescalated and not discounted)			
Total (escalated and not discounted)			
Total at NPV ($M)			

4.5.2 KEY ASSUMPTIONS / BASIS OF ESTIMATES

SOURCE OF COST INFORMATION AND CONTINGENCY ASSESSMENT

WSP licenses a large industry standard software package that allows detailed modelling of generation plant performance, and provides estimates of capital costs, based on internationally-sourced data. Outputs from this package, modified for known differences between New Zealand and other locations, have been used as the basis for estimating capital costs of plant.

Current land values in locations likely to be of interest for generation plant siting have been used to estimate land costs.

Current sale prices of logs, as advertised by major log exporters in New Zealand, have been used as the basis of fuel cost estimates.

WSP's information on common operational expenditure levels, researched for projects similar to the recommended base case, have been used to estimate fixed operational cost levels. Our project experience has also informed estimates of developmental costs.

All of the above has influenced the setting of contingency and funding risk, in order to obtain the expected 90th-percentile estimates.

The current biomass options all rely on the use of long-rotation exotic biomass, purchased on a spot market. While this is a reasonable assumption for the purposes of investigation, it is also likely that negotiations could reveal a more economical/advantageous supply basis. This topic would warrant detailed evaluation at a later stage.

GENERAL

- All expenditure values are stated in terms of 2022 NZ dollars
- Historical figures used in building up cost estimates have been escalated by the CPI Index
- Inflation (escalation) has been applied to all costs after 2023, using a rate of 3% (which reflects the expected long-term average and not the current rate of inflation)
- A discount rate has been applied to future costs from 2023, using the New Zealand Treasury rate for Infrastructure (Water and Energy) and Special Purpose (Single-Use) Buildings of 5% (as of August 2022).
- Goods and services tax is excluded.

DEVELOPMENT COSTS

The sum of the items below approximates Commercial Information estimated physical work costs.

- **Investigation** costs are for the design option development costs (including site optioneering and concept designs), as well as site field investigations
- **Consent** costs are for the preparation of applications for consents, licences and designations. This includes allowance for processing of applications in minimum timeframes
- **Design and Procurement** includes the development of designs for the purpose of consenting, with specimen designs to go to an engineer, procure and construct contract (EPCC) or design and construct. Design costs following the award of an assumed EPC contract are included within the capital cost estimates
- **Property -** Based upon an estimated rural land value Commercial Information for stockpile, processing and generation plant.

CAPITAL COSTS

- **Site clearance, earthworks and civil works -** Highly variable depending on site location, topography and requirements that are currently unknown
- **Log processing plant and equipment -** Estimate based on market rates for plant compared to Australian example
- **Transmission Cost -** Potential for significant variance in transmission distance
- **Power station -** High capital item. Base number used cost data from example project and model. Output: 500 MW for three months of a dry year period.

OWNER'S COSTS DURING DEVELOPMENT AND CONSTRUCTION PHASES (UPFRONT)

- Calculated Commercial Information physical works costs. This is expected to include owner costs during development phase such as management fees, financing, setting up management company and setting up supply contracts.
- When this item is combined with the Development item, they equate Commercial Information the physical works cost.

OWNER'S COSTS DURING OPERATIONAL PHASE

- An allowance Commercial Information has been made in the base estimate for the running of management company overseeing operation of the New Zealand Battery.

OPERATIONAL

- **Annual operational cost (non-dry year) -** Based on staff and labour estimates and salaries from Australian example (Reference Project 2).

- **Fuel cost (non-dry year) -** The Base estimate uses Commercial Information at the gate for material required in a normal year 3 yr. replenishment period (375,000 tonnes per annum). P50 obtained by Commercial Information contingency which correlates to a log cost Commercial Information and P90 equates to Commercial Information. Reference Project 3 below. See Reference Project 3 below. estimated cost data, which includes haulage and logistics

- **Annual operational cost (dry year) -** Based on staff and labour estimates and salaries from Australian example

- **Fuel cost (dry year) -** The Base estimate uses an optimistic Commercial Information at the gate for material required in a normal year 2 yr. recharge period (558,000 tonnes pa). P50 obtained by adding Commercial Information contingency, which correlates to a log cost of Commercial Information and P90 equates to Commercial Information The log price at the gate is variable for material required in a dry year, with a two-year recharge period and may be averaged across both supply conditions through negotiation of long-term commercial supply agreements. See Reference Project 3 below.

MAINTENANCE

- Over the 30-year life of the plant, maintenance costs Commercial Information the Capex
- **Annual maintenance** – Inspections and general minor maintenance of plant
- **Maintenance (short interval)** – Major Inspections and minor part replacement
- **Maintenance (medium interval)** – Routine maintenance and one minor breakdown
- **Maintenance (long interval)** – Planned maintenance and one major breakdown.

DECOMMISSIONING

- **Decommissioning cost** Commercial Information the capital cost.

REVENUE

- **Power sale (non-dry year)** – Converting the replenishment rate of 0.33 TWh to electricity and selling at an average Commercial Information over the year

- **Power sale (dry year)** – 1 TWh of battery discharge + the normal year 0.33 TWh. 1,330,000 MWh x Commercial Information = Commercial Information

4.5.3 OTHER PROJECT BENCHMARKS

There are limited project benchmarks that can be used to compare estimates for the biomass technology. These are provided in the table below.

Example project comparisons					
Project Name	Type/ Scale of project	Location	Date Construction Complete	Other Notes	Cost
Project 1 PEACE - Thermaflow Modelling Tool (Plant Engineering and Construction Estimator)	Model of 3 x 500 MW plant configurations to derive capex cost	Virtual - not constructed	N/A Models run July 2022	Based on industry standard estimating software. Configurations 6 x 85 MW combined turbine/boiler. 3 x 85 MW Combined turbine / boiler (x2) and 4 x 125 MW Combined turbine / boilers.	Commercial Information [redacted]
Project 2 3 x 350MW	Flexible coal generation - 1TW Peaking Plant	SW Australia	Planning stages	Opex estimation for the generation plant used as a comparison pro rata for the NZ Battery solution	
Project 3 Forestry Sector publicly available information	Log Supply	Central North Island	June '22	Low grade log processed per tonne	

4.6 SUMMARY

4.6.1 BIOMASS NZ BATTERY OPPORTUNITY

As a NZ Battery solution, biomass appears to present a robust option. It would use large regions of existing national exotic forestry. The technology has high maturity, reliability and efficiency and could provide a self-reliant New Zealand solution with high independence from international forces.

Exotic forestry that would be used in the solution is sustainably managed and deemed GHG neutral. While the base case has been set at 1 TWh (to balance biomass demand against competing uses/exports and constrain supply chain requirements) it could feasibly go to as large as around 4 TWh, in a staged approach that managed risks. This will require extensive commercial discussions with prospective biomass suppliers, together with significant stakeholder involvement.

The challenges for biomass predominantly relate to the supply chain and storage duration. Due to the limited duration of biomass storage (approximately two to five years, depending on storage medium selected), stock replenishment will be required in the scenario where dry years are spaced apart. This results in an ongoing supply chain cost and potential need to utilise expiring biomass. The supply chain requirement also results in associated carbon dioxide emissions. The 1 TWh size has been used to limit the collection radius required for logs, reducing transportation requirements.

A base case of white biomass (log chips) has been used, but an option of torrefied biomass (with potentially longer storage durations) remains a possibility. There is insufficient track record information available to finalise the optimum storage medium at this stage. To navigate this uncertainty, a staged approach to decision-making has been proposed, that will ultimately lead to a NZ Battery solution for the required 2030 operation date.

New Zealand also has existing plant that can likely be modified to use biomass (either torrefied or similarly modified). The remnant life of that plant is not known, but even if the remnant life were relatively short compared to the proposed life of new plant, a capex deferral option could be attractive.

From a benefits perspective, the supply chain requirements result in long-term, local employment benefits due to the job creation opportunities associated with the relatively labour-intensive biomass harvesting and supply chain logistics that would be permanently required, as well as seasonal dry year work gains.

4.6.2 OTHER INSIGHTS

OPTIONAL OTHER USES FOR STOCKPILE ROTATION MATERIAL

Assuming an average five-year return period for dry year generation requirements, and a two-year recharge period (during which no material is removed from the stockpile), it may be anticipated that, for an average of three years out of five, there will be material within the stockpile that will become end-of-life and need to be discarded. This material (equivalent to 3 x 0.33 = 1 TWh of surplus material on average) will become available at irregular times during any five-year interval.

Potential usages of this material include additional generation (either base, or part-load running) or supply to other biofuel users (e.g. third-party torrefaction plants or pulp/paper manufacturers) or others who seek biomass as feedstock. In addition, there are other industrial consumers who could accept irregular volumes of surplus material. While a market for this material has not yet been established, it is reasonable to expect that the sale of this material will significantly off-set original log purchase costs.

BIOFUELS

Biofuel derived from New Zealand-supplied biomass could also be used to fuel a number of "green peaker" plants (a renewable electricity generation plant with full controllability to start quickly and provide power during peak periods). This could provide additional resilience to a fully renewable New Zealand electricity system.

As New Zealand is currently proposing a significant decarbonisation effort, the installation of new biomass pre-processing (chipping, torrefaction or other) capabilities, and the possibility of intermittently available excess arising from a NZ Battery stockpile turnover may provide opportunities to produce biofuels economically from these by-products. The option of using existing CCGT and OCGT plant as potential "green peakers" utilising biofuels is deemed to be highly possible with some minor modifications.

Several risks and considerations are listed below:

- While development work has been carried out on a process to create ethanol from NZ white biomass, there is a risk that an insurmountable technical challenge will become apparent as the process is brought closer to commercialisation at a large scale. While the technology in development, described in Section 4.3.9 may be relevant, a range of challenges are presented i.e. the scale production of enzymes, large-scale thermal processes and/or the yield of the process.
- The technological maturity of options to produce liquid biofuel from NZ-sourced biomass (an option that would allow the use of GT's instead of future Rankine cycle generation plant) is likely to meet the threshold of TRL8 by 2030, however, there is a risk that the actual threshold will not be reached due to either specific hurdles or lack of scale-up effort, or inadequate economic incentive
- Although efficient power-generation options are available for biofuel, the production of biofuel has a yield that is not well known as yet, and this will have an effect on the total biomass required as feedstock
- Risk that the process refinements undertaken during the development process will not demonstrate a clear advantage over the option to use solid biomass as the basis for power generation
- Risk that scale-up work will reveal that economics are unfavourable - either by comparison of product end-cost to imported options or precursors, or by comparison to the base-case option of Rankine-cycle firing of white biomass
- Risk that large-scale biofuel yields will require such significant increases in total biomass requirement, as to cause supply difficulty or constraints
- Risk that, at large-scale, the process environmental effects (waste disposal, etc) will become a barrier to implementation
- Risk that it will prove either commercially or technically impossible to find a party willing to carry out the development and large-scale implementation work in New Zealand.

We recommend that these risks are managed as follows:

- A high-level review of process steps leading to a biofuel derived from *pinus radiata*, and a review of experimentation carried out by entities such as Scion have not revealed insurmountable technical risks
- A possible timeline through to commissioning of major bioenergy generation plant suggests there is time for a significant scale-up and refinement process to occur without jeopardising options for (solid) biomass fuel. A staged development process could also consider alternative feedstocks that meet project high-level criteria, but do not overlap with base case feedstock requirements
- There are likely to be temporary options to import biofuel, pending development of a domestic biofuel capability.

There is a national awareness of New Zealand's dependence on imported transport fuel, and current supply chain pressures, for which domestically produced biofuels could offer at least partial substitution options. A biofuel plant in New Zealand could be significant, for reasons outside the requirements of the NZ Battery Project.

POLICY CONTEXT

This study has reviewed the concepts of greenhouse gas neutrality and the cyclic nature of carbon sequestration in relation to woody biomass and the forestry sector. The relationship with the New Zealand Emissions Trading Scheme has been discussed, however, there are additional strategic policy interdependencies which should also be taken into consideration, should this option be adopted for further development.

New Zealand has recently published its first national emissions reduction plan - Te hau mārohi ki anamata as the Government's response to the Climate Change Commission's recommendations and commitments to the Paris Agreement 2016 and the Climate Change Response (Zero Carbon) Amendment Act 2019. Key aspects of this plan are equitable transition, supported by a circular economy and acceleration of investment in the bioeconomy.

> "Moving to a circular economy with a thriving bioeconomy will support our economic and social wellbeing and lead to a better balance between the emissions we generate and the environment's ability to store these."

HISTORICAL EXPERIENCE

The process of developing this proposal for a biomass NZ Battery solution has involved extensive consultation. Significant effort has been made to consult with the large body of expertise that exists in New Zealand, including but not limited to Scion and the NZ Bioenergy Association. Care has also been taken to learn from project experience elsewhere. While Drax in the UK has demonstrated that large-scale, long-term power generation from biomass is possible, it has been criticised for using fuel (white pellets) that incur high parasitic energy costs and its dependency on transnational shipping to source pellets. Ontario Power demonstrated the feasibility of converting a large-scale coal plant to torrefied biomass but became reliant on fuel with a high parasitic energy cost (torrefied biomass) that could only be sourced from Scandinavia, due to the local supply chain not being economically viable. Our base case proposal uses fuel requiring a practical minimum of parasitic energy for preparation, a high-efficiency generating plant, and avoids all but the bare minimum of transportation, by proposing power station locations adjacent to the sustainably managed forest resource.

4.6.3 GUIDANCE FOR NEXT STEPS

The current evaluation is at the pre-feasibility level, establishing realistic high-level plant options and specifications, which require further clarification.

The straightforward test work that will allow a decision to proceed with the base case, or a change to an alternative case, would be of high value and it is recommended that this proceeds swiftly.

PLANT SELECTION AND OPTIMISING THE BIOMASS SOLUTION

WSP has developed a biomass supply chain, storage life and energy conversion calculation spreadsheet model that allows the user to fully adjust all the major supply chain parameters, storage medium and test sensitivities. It is recommended that this tool is used in conjunction with MBIE's economic modelling and counterfactual scenario planning to test possible variations of normal year vs dry year generation and plant sizes. The tool can be used, together with costs and insights of other factors, to develop an optimised solution that best addresses NZ Battery Project objectives. This optimised solution could form the basis for a concept design to be taken forward to Phase 2 detailed investigations.

4.6.4 PRELIMINARY IMPLEMENTATION SCHEDULE

The following schedule is provided as a draft to illustrate a potential implementation pathway to achieving a completed biomass NZ Battery by 2030.

PRELIMINARY SCHEDULE BASIS

The biomass base case and risk adjusted schedules assume a start date of April 2023 and a target end-date (handover of commissioned plant) in 2030. The risk adjusted schedule allows additional time for reaching the decision for notice to proceed, and the pre-procurement, procurement and construction stages, resulting an additional 2 years (and a mid point of 1 year).

Key to finalising a schedule is the confirmation of key decisions and the subsequent large amount of conceptual and detailed design work that needs to be completed, in order to finalise project deliverables.

Significant time must be allowed for Iwi and other key stakeholders consultation, as the supply chain for biomass is critical to this solution option and the development of long-term supply contracts will require time and effort.

Significant time will be required for consenting, however it is difficult to predict the significant of national importance that may be attached to this project, upon the consenting process.

Since the bioenergy solution includes some options - which are dependent upon testing outcomes, durations for these have been included for consideration into the schedule.

The site construction duration will depend on the current state of the selected locations. If the site requires substantial geotechnical preparation, this will require more time.

Once the major civil works are completed and the major plant items are delivered to site, construction of all main process areas can continue, with many parallel paths. The physical interconnection work and control system integration can then occur.

Negotiations

Final process plant testing and commissioning will be a critical time towards the end of this schedule.

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Ontario power, Thunder Bay (Canada) - White pellets, also torrefied pellets.

The Alholmens Kraft power plant in Finland was constructed in 1999 and commissioned in 2001. The Alholmens Kraft power plant has a capacity of 240 megawatts (MWe), producing around 1300 gigawatt-hour (GWh) of electricity per year (OPET Finland, 2001). The plant is powered by a combination of wood-based fuels (30-35%), forest residues (5-15%), peat (45-55%) and coal (10%). The total cost invested on this project was approximately 170 million Euro (285 million NZD) (OPET Finland, 2001).

Drax power station "...The station has a capacity of 3,906 megawatts (MW)..." "...The site near Selby in North Yorkshire provides the most renewable power of any single location in the UK, some 14 terawatt-hours (TWh) or enough electricity to power the equivalent of four million homes. Drax Power Station has evolved considerably since construction began in the 1960s..." < https://www.drax.com/about-us/our-sites-and-businesses/drax-power-station/>. This station does not use precisely the same fuel specification as is envisaged, but this is not considered to affect the assessment of technology readiness

The Seinajoki biomass power plant located in southern Ostrobothnia, Finland has a specified total capacity of 120 megawatts (MWe). The power plant is owned by Vaskiluodon Voima and was commissioned in the 1990s. The Seinajoki power plant can produce 400-800 gigawatt-hour (GWh) of electricity annually, with fuel that primarily uses wood residues and forest chips as its feedstock. The plant was designed to use circulating fluidised bed boiler and condensing turbine to achieve high combustion efficiency while minimising the formation of nitrogen oxides due to its low combustion temperatures (Vaskiluodon Voima, 2017)

A significant number of international firms can offer woody biomass processing equipment

A significant number of international firms can offer Rankine cycle power generation systems, from boilers to turbogenerators.

Very large numbers of liquid fuelled CCGT and Rankine cycle and ICE power generation plant are installed worldwide.

GEOTHERMAL

5 GEOTHERMAL

5.1 INTRODUCTION TO SOLUTION

Aotearoa's geothermal landscape and industry present a significant opportunity for a NZ Battery solution.

Geothermal energy is a renewable energy source, independent of weather, that can be relied on to generate when needed. It is a familiar and well-established technology in New Zealand, with over sixty years of operating history and engineers and scientists recognised globally for their skill and experience. The industry has over 1000 MW of plant across ~20 sites, generating around 7.5 TWh of electricity per annum, which typically operate at very high rates of utilisation.

Our previous options analysis findings led to controlled, schedulable geothermal being recommended for further consideration as a NZ Battery solution (refer to the Options Analysis Report for further background discussion and commentary).

Nga Awa Purua Geothermal Station (Credit: NZ Geothermal Assn)

Geothermal energy is already included in the portfolio of generation options to meet normal market operation and development. Establishing a geothermal NZ Battery would involve bringing forward a number of geothermal stations that would otherwise not be implemented until after 2030, and operating them in a new way, as long-term "controlled schedulable" plants that can ramp up electricity generation in dry years, as needed. The intention is that traditional geothermal power generation technologies would be used, with the inclusion of some technically proven additional engineering design, operating and maintenance features. These additional features would allow the below-ground geothermal reservoir to be run at a low load (turned down) condition, while allowing several of the above-ground power plants to be switched off (mothballed) during normal years, in readiness to then be ramped up and run at full load in dry years.

A key question to be answered in the feasibility assessments is the realistically achievable amount of geothermal power plant that could be developed and built for NZ Battery purposes by 2030, given potential resource, consenting, and industry constraints and without displacing any plants that would be expected to be built under normal market developments.

The *large-scale*, *long-term* and *renewable* key criterion are all satisfied by this technology option.

One of the key advantages of geothermal is its inherent energy storage, meaning it does not need to be recharged like other technology options. Geothermal generation could continue operating, if required, to provide dry year reserve energy over a longer period at minimal additional cost.

5.2 KEY CONSIDERATIONS

5.2.1 RECOGNISING THE ROLE OF KAITIAKI AND INCUMBENTS

Māori have strong links to New Zealand's geothermal resource, for whom it is a taonga. Where Māori have retained land over a resource, they retain an interest in the resource for which they play a kaitiakitanga role. Through land ownership, access to all or part of these resources is controlled. Should these roles and rights be over-ridden, it would be regarded as a breach of the Treaty of Waitangi. These landowners are responsible for the development of the land above the resource and will also have positions on resource development. Many of the associated Trusts are interested in partnership or leadership of geothermal developments and are considered developers in their own right.

There are a range of incumbent field developers who may have already tied up exclusive geothermal development rights with landowners and who will typically hold the detailed technical knowledge on a geothermal field and its capability. This commercial information is generally kept confidential, with disclosures in the consenting process being an important exception. Hence, a party other than the incumbent would need to undertake a parallel exploration programme involving tens of millions of dollars and several years to gain sufficient information and resource assurance to progress a proposal.

Partnering with existing developers and operators will have multiple benefits. These parties can bring commercial knowledge, support for consenting, exploration and implementation contract management and ultimately support for operations and maintenance.

Any development would require consultation with all stakeholders and partnership with Māori. It would also require co-operation with incumbent interests on the field, in order to access land for geothermal development and information.

Impact on Base Case Development

We acknowledge that any geothermal battery project must include a consultation and partnership approach with local iwi, ensuring the co-operation of kaitiaki and incumbents.

5.2.2 GEOTHERMAL RESOURCE

To date, geothermal generation in New Zealand has been located exclusively on the high temperature fields throughout the Taupō Volcanic Zone in the Central North Island and at Ngāwhā in Northland (see map below). Some fields are protected under regional plans, while others are available for development.

Negotiations

The sites for a NZ Battery could be located across the above area at multiple locations, matched to resource capacity and stakeholder interests. The key features of this area are:

- Proximity to similar stations and support services
- Various fields are designated for development by regional councils (and some may have existing unused consents by incumbent developers)
- Development is compatible with existing land uses e.g. farming and can align with stakeholder interests
- Within a few kilometres of 110 and 220kV transmission lines
- Proximity to major roads and accessible to ports, through which equipment could be transported

- Within 270km of Auckland demand centre.

Ahead of exploration, it is challenging to establish a fully informed picture of the available capacity of New Zealand's geothermal fields as, unlike the oil and gas industry, there is no regulated public disclosure of this information.

Actual field capacity is established through surface geoscience, exploration well drilling and testing, followed by staged development with careful monitoring of field response. This is followed by further modelling of potential response to a larger or alternative development.

Some useful information on fields is available from pre-1980's government exploration programmes. Where further exploration or development has been, or is being, undertaken by private or public interests, the results are not disclosed due to their commercial sensitivity, with limited public disclosure necessary for resource consents.

The consenting process for geothermal field development contains provision for competition on any field. Developers typically aim to minimise this risk through several strategies. One strategy is attempted negotiation of exclusive land access rights with the large landowners over a field. Another strategy involves exploration and reservoir modelling to show that their planned development is sustainable in the long-term, rather than proving the ultimate capacity of the field. The result is that, after testing and numerical reservoir simulation, a field will appear fully loaded with the planned development. This hinders a competitor "free-riding" on the exploration and modelling results of the initial developer. The result is that there may be some upside potential for future increases in actual geothermal field capacities from the initially available figures.

In the absence of detailed commercial information, assessments of field capacity were made at a high level, by recognised experts using stored heat techniques. Consenting ability and Business as Usual (BAU) timing were also considered in setting up a Generation Stack (Lawless et al, 2020) as shown in Table 5-1.

Table 5-1: Generation Stack

Project	MW	BAU Earliest Date[1]	Project	MW	BAU Earliest Date[1]
Tauhara 2b	80	2026	Tauhara 3	30	2035
Mangakino	25	2030	Horohoro	5	2040
Mōkai 4	25	2030	Ātiamuri	5	2040
Ngatamariki 2	50	2030	Rotokawa 4	50	2040
Rotokawa 3	50	2030	Tokaanu 2	100	2040
Kawerau 2	50	2030	Tikitere 2	50	2040
Rotoma 1	25	2030	Tāheke 2	25	2040
Tokaanu 1	20	2030	Reporoa 2	25	2040
Tikitere 1	50	2030	Ngāwhā 5	25	2041
Tāheke 1	25	2030	Tāheke 3	25	2050
Reporoa 1	25	2030	Reporoa 3	25	2050
Ngāwhā 4	25	2031	Ngāwhā 6	25	2051

[1]BAU Earliest Date is the earliest date plant is expected to be constructed in a normal 'business as usual' scenario (from Lawless et al, 2020)

IMPACT ON BASE CASE DEVELOPMENT

Targeting practically achievable geothermal development locations (sites) and ranking and selecting sites that achieve the best balance of:

- Steam fields of sufficient size to allow for multiple plants to be deployed across an integrated field, helping to achieve a minimum reservoir output to flow continuously
- Acceptably high enthalpy geothermal resources.

AVOIDING DISPLACEMENT OF BUSINESS AS USUAL GEOTHERMAL DEVELOPMENTS

Of all the technology options considered, geothermal is most closely linked to the current electricity generation market. Therefore, a key consideration is to avoid the potential market implications of any NZ Battery plants displacing sites that may otherwise be built before 2030 through normal market forces. Power plants developed for NZ Battery generation should not be diverted from the currently expected developments for baseload generation.

IMPACT ON BASE CASE DEVELOPMENT

Sites that are not at the "front of the stack" of potential future geothermal developments. The broad concept aims towards ~400 MW of potentially feasible sites that appear to be available from the latter part of the generation stack and are physically located away from established developments.

5.2.3 SUBSURFACE AND WELL OPERATION

Traditionally, most geothermal systems operate on a continuous basis, with constant flow and temperature profiles. The feasibility of geothermal energy as an NZ Battery solution will depend on its ability to operate in a non-traditional long-term "controlled schedulable" manner. This means, instead of running at full capacity in a normal year, the subsurface reservoir would need to run at low load (be turned down) or be entirely shut in and only opened up when needed for NZ Battery duty.

Heavy and frequent cycling of wells is undesirable. There are sub-surface risks associated through repetitive shut in or turn down of the system, as follows:

- It may become harder to keep the well system free of mineral precipitation arising from geochemical reactions, due to temperature fluctuations leading to partial or full blockage and reduced output
- A constantly changing boiling point in the well (through pressure changes with cycling) could pick at fresh rock faces, bringing fine material to the surface to foul steam field equipment or reinjection wells
- The cycling up and down of the system may give rise to fluctuations in temperature by up to 100°C throughout a well, leading to varying thermal strains in the well casing, associated casing joints and supporting cement. This may degrade the well, causing potential issues with well integrity and leakage
- If wells were effectively shut and put on bleed, then gases could accumulate around surface facilities, creating hazards for workers
- For some wells that are shut in, there can be difficulties with starting flow again.

These risks generally favour continuously operating systems i.e. running the sub-surface resource at low load (and topside plants in a modular manner) rather than fully shutting off the wells in normal years. There are uncertainties with both approaches, however, detrimental effects are more likely to be reduced by using the low load mode of operation. The risks are also more easily managed with the routine maintenance and inspection of continually running geothermal wells and plant, as opposed to bringing online only in dry years. In all cases, the continuous flow of sub-surface geothermal fluids, where possible, is preferred.

It is worth noting that some fields have been operated in a cyclical mode for certain applications. Examples include the original operation of Poihipi station, though this was from a steam reservoir initially, and steam supply to the Kawerau mill, with its changeable load (using steam venting and remote control of large responsive wells). These examples suggest that risks are manageable in some cases. Also that the principal risks associated with on/off and schedulable operation of geothermal subsurface systems (potential mineral precipitation/fouling and well integrity issues) can be managed.

In managing the risks associated with sub-surface and well operation, a detailed strategy considering Measuring, Monitoring, and Verification (MMV) is required and must be adhered to. In tandem with MMV, proper maintenance and operation of the wells is vitally important to a successful geothermal project.

No two geothermal reservoir systems will behave identically when subject to cyclical operational changes. Reservoir geoscience and well design/performance must be understood to determine whether certain geologies, reservoir fluid properties or surface system operational ranges are likely to degrade reservoir and/or well performance. A conservative approach assumes the need for continuous running at low load for all fields, but field-specific operation may show that complete long-term shutdown at some locations is a possibility.

IMPACT ON BASE CASE DEVELOPMENT

The risks associated with on/off operation of geothermal wells can probably be minimised by using a low load (turned down) mode of operation. The low load approach is also more likely to be assured, consented and financed, as behaviour will be more predictable, and the lifetime of the geothermal wells and reservoir can be better sustained.

Therefore, we recommend that the geothermal reservoirs are run in a low load mode, rather than be fully shut in (on/off) during normal years. The wells would operate at constant low load, then step up to new constant levels, as required, during dry years.

This mode of subsurface reservoir operation gives rise to several questions around the degree of turn down that could be achieved. This is recommended at 25%, with further details of the investigations and system turn down summarised in Appendix C.

The preferred method of operation is that, in normal years, each site's plant would run at low turn down, by modulating wellhead valves to a constant 25% open, and running one unit of four geothermal power station units at full load, with other units mothballed. Hence, the proposed geothermal base case turn down would be 25% of full load flow requirement. In dry years, the plant could be ramped up over approximately two weeks to 100% (or a chosen increment to best match the dry year energy requirement) by opening up the wellhead valves and de-mothballing and ramping up the geothermal plants to bring online an additional 75% capacity of dry year backup generation.

5.2.4 NZ AND INTERNATIONAL GEOTHERMAL INDUSTRY CAPACITY

While New Zealand has a strong industry to support the design and construction of geothermal infrastructure, the deployment of significant new geothermal plant in the period leading up to 2030 would likely stretch New Zealand's geothermal industry capability. With the large-scale nature of the NZ Battery Project, a geothermal solution would need to be split across multiple sites, which are developed, consented, designed and constructed at least partly in parallel. This would present a resourcing challenge i.e. sourcing sufficient geothermal industry specialists to carry out the research and engineering required to develop the geothermal stations, in addition to any BAU developments.

Significant geothermal deployment has been achieved before in New Zealand, with 560 MW of new geothermal capacity commissioned across five sites within a seven-year period (2008-2014). During this geothermal "boom", developers and supporting industries used a range of "Make–Fix–Buy" approaches vs adopting a co-ordinated strategy to secure human capital. "Making" is the process of taking a long-term approach to development, with the establishment of schools (often with developer and large consultancy co-operation), or recruitment of young graduates from university. "Fixing" involves recruiting people with related skills, then upskilling to adapt skills to geothermal applications. “Buying” refers to the direct recruitment of experienced personnel, either from other New Zealand companies or internationally.

CURRENT RESOURCING SITUATION

There is currently high employment in New Zealand, and we understand that large, national infrastructure projects have had difficulty recently in recruiting local geothermal specialists. There is also an issue with the number of specialists who are nearing retirement age. A “Make-Fix–Buy" strategy could be used in preparation for a geothermal NZ Battery by 2030, recognising there may be surpluses of personnel in countries where there have been recent booms. For example, the Philippines remains a strong recruiting ground, due to it being the third largest geothermal installed capacity globally (with little recent growth) and the quality of its geothermal specialists.

Main station and steam field construction could be on a turnkey/Engineer Procure Construct (EPC) basis, with the same or separate contractor(s) for the station and steam field, and a further contract for the drilling. Normally, these contracts would use international companies that, at least in part, draw on New Zealand resources, especially for civil works and steam field development. A wide spread of New Zealand companies played key roles in the last “boom”.

There are no particular import restrictions or protections of equipment or materials required. Our review of international commissioning of plant provides an indication of what can be achieved. Global surveys of geothermal construction indicate that, internationally, the five-year period between 2015 to 2020 saw dramatic growth - for Indonesia (over 900 MW), Kenya (600 MW), Turkey (almost 1200 MW) and the USA (400 MW). International businesses supporting geothermal development have been able to adjust to these significant steps and can clearly support national developments in the range of 400–500 MW, and potentially more.

New Zealand achieved a growth rate of over 400 MW over a five-year period to 2015. We, therefore, anticipate that the industry will be able to adjust to a reasonably significant step, using both New Zealand-based companies (who typically have international offices to draw upon) and international contractors.

IMPACT ON BASE CASE DEVELOPMENT

This consideration has been incorporated into our base case design, by selecting a target total size in MWs at a practical, feasible range to maximise the likelihood of successful implementation by 2030. To keep the risks to an acceptable level, we would recommend a geothermal battery target of nominally 400-500 MW of new geothermal deployment by 2030, independent of any BAU geothermal development.

A practice of major internationally tendered contracts can be followed, where tenderers are supported by a Geothermal Capability Register of New Zealand companies, so that resident expertise can be maximised.

To maximise success, we recommend a flexible procurement model, whether by Alliance, EPC, Public-Private-Partnership, Design-Build-Operate, or other variants.

Target a selection of fields that can support a mixture of condensing flash and ORC binary cycle geothermal plant (allowing spread of plant supply capacity across multiple international OEMs).

DRILLING CAPACITY

A critical consideration for any geothermal power development is well-drilling activity, for resource exploration, production and reinjection purposes.

Figure 5-1 below shows historical deep geothermal drilling on New Zealand geothermal fields.

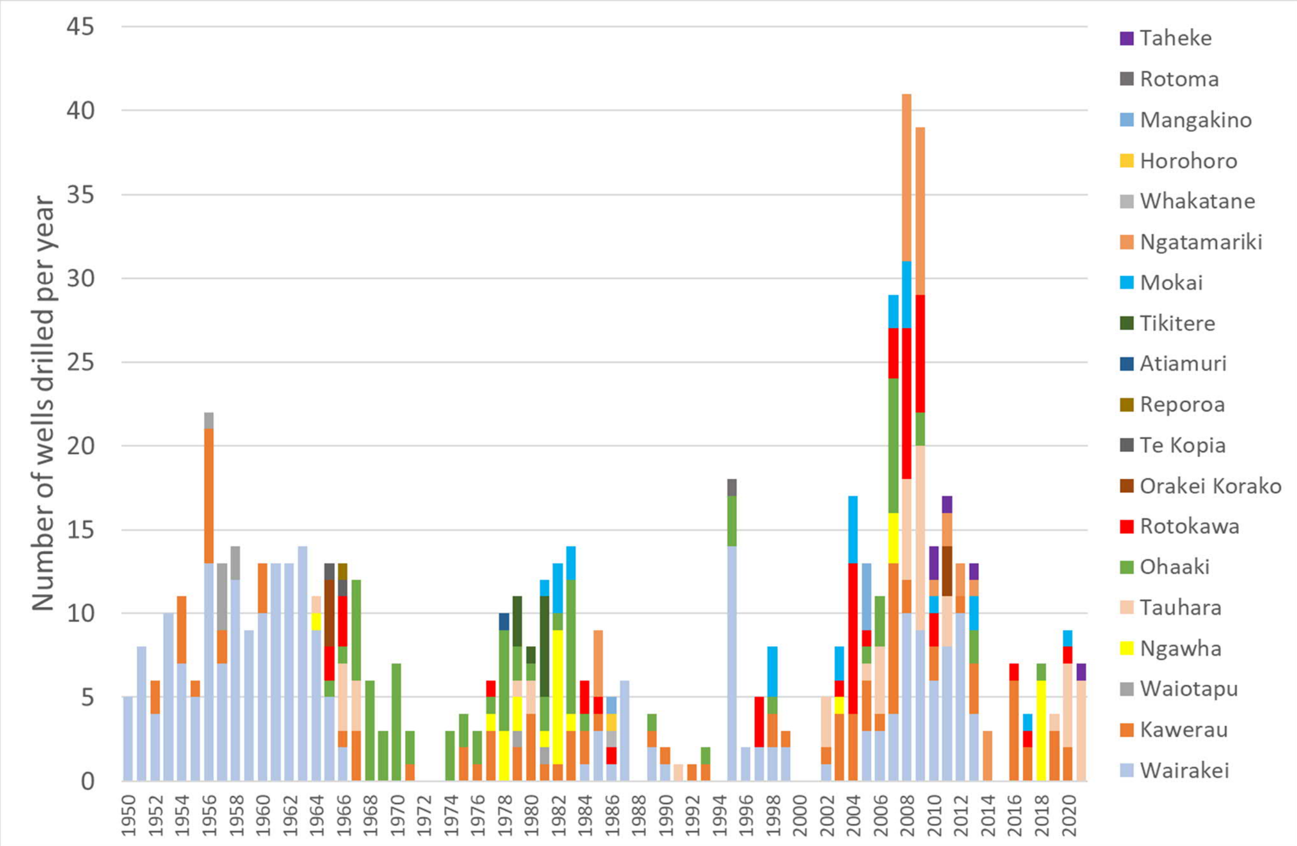


Figure 5-1: Historical number of deep geothermal wells drilled in New Zealand.

Geothermal resources are accessed through wells with multiple concentric casings cemented in place in the upper sections and now drilled to depths of the order of 2kms.

New Zealand's historic peak in drilling was during the recent development boom in the 2000's. Drilling preceded commissioning generally by two or three years, with major drilling programmes (such as Te Mihi) spread out over as much as ten years.

Peak drilling rate was about 40 wells per year but, of these, about 10 were shallow monitor wells, so peak production/reinjection well drilling rate was about 30 wells per year. Drilling will also be required to account for rundown of the existing stock of wells. Allowing 3%/annum run-down of wells implies the need for about nine makeup wells per year. So, if past drilling industry could sustain 30 wells per year and nine of these wells will be to maintain existing production, then 21 wells per year could be dedicated to the Battery project. Drilling activity during the period from 2023 to the beginning of 2030 implies opportunity to drill wells for approximately 600 MW development, if it were available.

In practice, this analysis is based on use of a 9 $^{5}/_{8}$" diameter production casing for wells and there has been a recent trend towards use of larger 13 $^{3}/_{8}$" diameter wells. These will be slower to drill, however, this will be offset by the potentially greater production or reinjection capacity, resulting in less wells being required.

IMPACT ON BASE CASE DEVELOPMENT

Given the well drilling capacity considerations, we recommend targeting no more than 600 MW of new NZ Battery sites before 2030.

5.2.5 TIMEFRAME FOR DEVELOPMENT

It can take more than a year for initial science, environmental and social studies, and concept development for consenting and the project consenting process can take a year. In a compressed programme, contracts can be drafted through the consenting process, but several months should be allowed for final negotiations.

If the field is a greenfield development, initial consents will cover exploration drilling and testing, after which consents could be sought for a full development. The development consent process could start as early as 2 ½ years from project kick-off. If the project is a brownfield development, working with incumbents and kaitiaki, progress straight to development consents is possible, with the significant shortening of time this presents.

Preliminary site civil works would then follow for an estimated six months, enabling access and constructing drilling pads. A single drilling rig could undertake a five well programme over a year, however, total drilling time for each project would depend on its size and number of rigs contracted, but conceivably could be three years. Wells would be progressively tested as production and reinjection couplets are developed. Contracts for station and steam field could conceivably be implemented over two years, and would ideally be timed to finish with the completion of well drilling and testing. On this basis, a tight schedule to completion, with multiple projects running in parallel, could total six years.

However, many fields have already had, or are in the process of carrying out, initial exploration. Some sites e.g. Kawerau and Tauhara may already have unutilised consents, which could present considerable time savings if an industry co-operation approach was applied.

IMPACT ON BASE CASE DEVELOPMENT

We recommend that approximately 400–500 MW of sites are targeted. These should be developed with a comprehensive project-wide schedule approach to completion, involving multiple power stations, with some carried out in parallel or staggered, where land and developer negotiations require it.

CONSENTING

Geothermal consenting processes are well established, with Regional Plans giving clear guidance on which fields are considered acceptable for development. Regional Councils currently allow averaging of flows over a year, to determine compliance with take and discharge limitations. For the NZ Battery Project, the additional dry year generation plant may have little use over several years, then be ramped up to peak capacity either gradually or over a period of weeks. Therefore, consenting will need to allow flow averaging (to ensure sustainability) over periods of, say, five years. In the intergenerational context used for planning purposes, five-year averaging would seem appropriate, however, this new approach to consenting approvals would require consultation and agreement from councils.

A potential issue is the upcoming changes associated with replacement of the Resource Management Act 1991, with a collection of new legislation including the Natural and Built

Environments Act. These changes may undermine confidence in procedures of an established system with its own case law. To avoid delays, transition provisions will need to allow projects to proceed through these established processes out to 2030 (or longer).

IMPACT ON BASE CASE DEVELOPMENT

We recommend that the potential impacts of the above risks are managed through incorporating the following measures into the execution strategy and approach:

- Prioritising options up-front and early involvement of local stakeholders and interested parties
- Choosing locations of lower consenting risk and/or having existing consents
- Increasing likelihood of achieving consenting through early interaction with Regional Councils (discussing potential new approaches to consenting), landowners, and/or incumbents favourable to geothermal development
- Timing for consenting and design to be well planned via a comprehensive project-wide schedule approach.

5.2.6 GEOTHERMAL NCG EXTRACTION AND REINJECTION (CARBON CAPTURE)

Geothermal power production may result in greenhouse gas (GHG) emissions, mostly by release of carbon dioxide (CO_2) (typically greater than 95% of the gas constituents), together with other non-condensable gases (NCGs). Most New Zealand fields are low emitters (with an overall average of 52 g CO_2-e/kWh), with exceptions being Ōhaaki and Ngāwhā, though these are still much less than thermal power emissions per kWh generated.

The geothermal battery is intended as part of a transition to fully renewable, low emission electricity generation. As such, it is undesirable for the geothermal Battery plant to be a significant source of CO_2 when operating. With this in mind, gas that is already captured and would otherwise be dispersed above the cooling tower should be reinjected into the reservoir, if feasible, and if no other positive applications (such as CO_2 supply for glasshouses) are available.

There is a risk that an inability to deploy carbon capture within the reservoir for NZ Battery geothermal plants at a reasonable cost could result in unacceptable carbon emissions associated with operation of the plant. Our cost estimates have allowed sufficient CO_2 capture technology to extract and dispose of the cycle NCG output. The CO_2 extracted would be directed to the underground aquifer for permanent capture. It is acknowledged that following reinjection, some residual CO_2 and NCG emissions may occur from the subsurface, and a nominal figure of 50% of unmitigated operational CO_2 emissions re-release has been allowed for, incurring an associated carbon charge.

If the NCGs discharged by geothermal power stations that have no alternative use could be returned to the reservoir, it would make a significant impact on the CO_2 lifecycle emissions for this technology. Mercury has reported that they have undertaken successful gas reinjection trials at Ngatamariki Power Station in the Waikato Region, essentially mixing gas with brine at the surface under normal reinjection pressures. Contact Energy is in the process of installing equipment at Te Huka Power Station in Taupō, to trial NCG capture and reinjection from an ORC power plant. Eastland and Top Energy/Ngāwhā Generation plan to start trials at their respective ORC plant, which is expected to be more amenable to gas reinjection than plant with direct contact condensers, because of the absence of oxygenated water.

As for other reinjection programmes, gas reinjection will require ongoing monitoring and adaptive management.

Internationally, CO_2 reinjection trials in Iceland, the US and Turkey have been carried out over the past 15 years, using gas scrubbing towers or gas compression. Appendix C provides further details and assessment of the viability of CO_2 extraction and reinjection as an option for deployment as part of a geothermal NZ Battery solution.

IMPACT ON BASE CASE DEVELOPMENT

We recommend that best practice CO_2 extraction and reinjection is used, both to minimise surface environmental effects and maintain reservoir pressure. All NCGs, including CO_2, will be reinjected, rather than discharged directly to atmosphere.

Ngāwhā has been excluded from consideration, on the basis of its high gas content/MWh, however, if full gas reinjection trials prove viable, this field could also be considered.

5.3 BASE CASE

5.3.1 BASE CASE DEVELOPMENT

The intention with the geothermal battery concept base case is to employ largely traditional geothermal technology with some bespoke engineering and operational enhancements, across a portfolio of currently undeveloped “back of the stack” greenfield geothermal fields.

It is expected that the two main geothermal plant types (flash steam and ORC binary) will be deployed. Both of these technologies can be configured to provide long-term schedulable operation. In addition, the ORC binary plant may be able to provide the option of flexible short-term load following operation, if this proceeded as part of the project.

The concept involves installing four generating units per field, with a quarter of this capacity continuously running (to minimise risks associated with on/off subsurface reservoir operation). Non-operating station units will be mothballed in between duty periods. When battery operation is required in a dry year, mothballed units will be set up for normal operation and wells will be progressively opened to fully load the units.

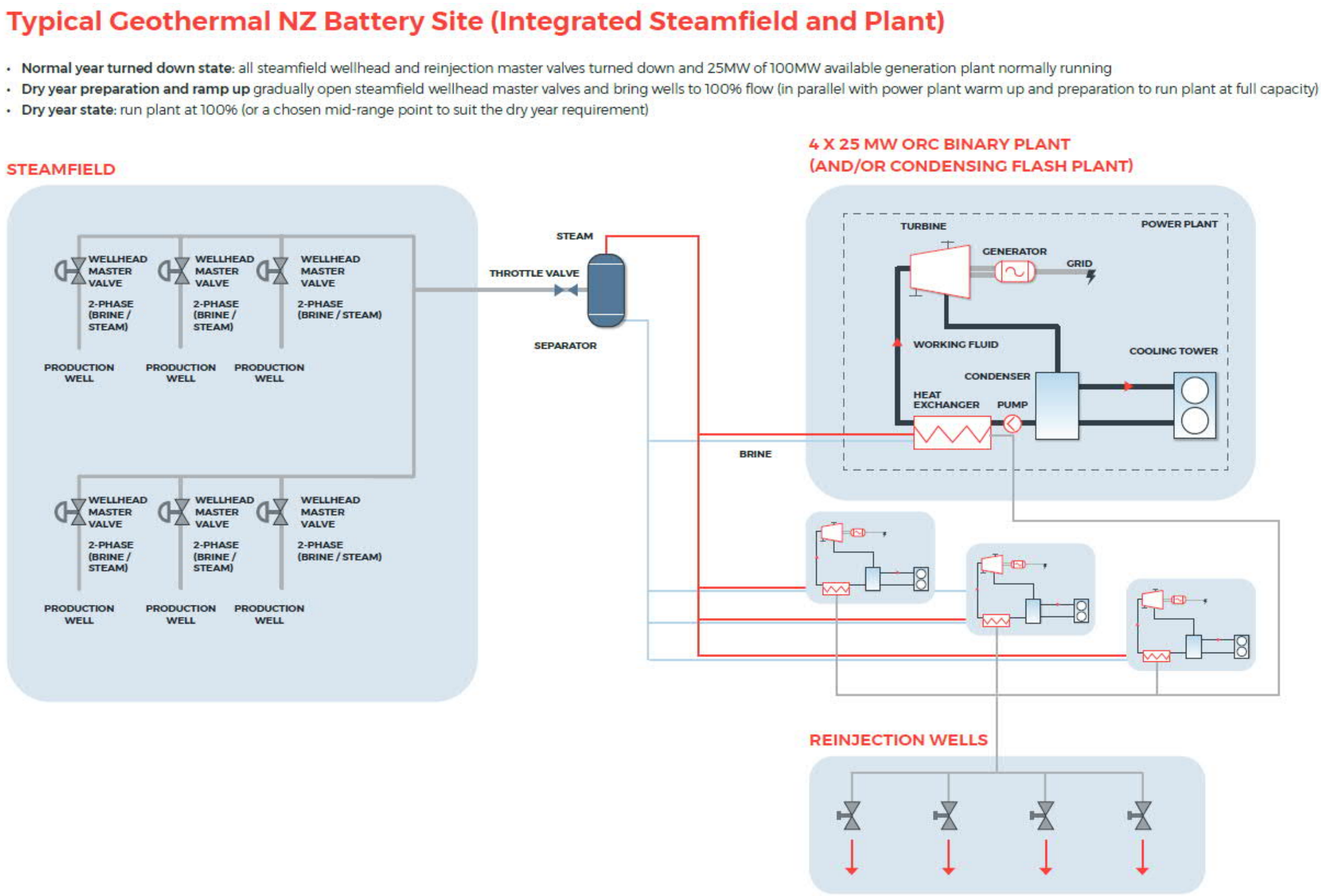
To spread development risks, a portfolio of fields has been selected. The fields at the back of the MBIE generation stack are generally greenfield, so there will be uncertainty about eventual production capability. To minimise these risks, exploration drilling prior to seeking full development consents would be scheduled in the programme.

The portfolio would allow for differing rates of progress with potential partners, which will include iwi representative groups and commercial entities. We would emphasise that, although “back of the stack” fields are assumed, there have been no discussions with parties and no specific plans for any field. The strategy would be reliant on effective partnering. Partnerships with iwi groups and Māori trusts will both recognise the kaitiaki role of these parties and provide opportunity for commercial benefits to allow involved.

As a Government-initiated project, a geothermal NZ Battery will need to demonstrate environmental management best practice. There are a range of best practices already adopted by New Zealand geothermal projects that will be used, and key among these is reinjection of brines and condensate. This mitigates effects on surface features through reservoir pressure support, addresses a range of potential impacts on biota at the surface and minimises risk of subsidence. The project is part of a national aspiration to transition to low CO_2 emission electricity generation, so the CO_2 (and other gas) emissions from the geothermal battery should be further minimised. To that end, gas reinjection has been chosen for all field-sourced gas. In existing geothermal plants (conventional flash or ORC stations), this is already collected in, and removed from, the condensers and dispersed in the cooling tower plume. The base case implementation strategy involves taking this collected gas and injecting it back into the reservoir (in a similar manner to current New Zealand NCG/CO_2 gas injection trials).

5.3.2 BASE CASE DESCRIPTION

PROPOSED BASE CASE BLOCK FLOW DIAGRAM



PROPOSED BASE CASE

300 MW (dry year additional capacity of 400MW new plant) 0.6 TWh (over three months), 1.2 TWh (over six months)

The proposed base case is for New Zealand to build 400 MW of new greenfield geothermal power stations at several (currently undeveloped) sites distributed across New Zealand's known geothermal regions (primarily the Taupō Volcanic Zone). The generation plant would be built in increments of as low as 5 MW, but typically would be in developments of 25 MW, 50 MW, and 150 MW plants. These could then be brought on, as required, for dry years in controlled increments (e.g. in 25–50 MW tranches), depending on the extent of the energy gap. These could be deployed with an integrated steam field approach, by drilling multiple wells and building multiple condensing flash and binary cycle ORC plants, utilising NCG/CO_2 extraction and reinjection technology.

In normal years, the plant at each site would run at low turn down, by modulating wellhead valves to roughly 25% open and running one unit of geothermal plant at full load (for either condensing flash or binary cycle ORC), with other units mothballed. In dry years, the plant could be ramped up over approximately two weeks to 100% (or a chosen mid-range point to suit the dry year requirement) by opening up the wellhead valves, de-mothballing and ramping up the topside geothermal plants to bring online an additional 300 MW of dry year back-up generation. The 300 MW of additional generation equates to 0.6 TWh of energy over a three-month period.

POWER GENERATION CAPACITY

Power generation capacity would be located across multiple sites, matched to the resource and split into (nominally) four units at each site. The technology will likely include a mix of flash steam and Organic Rankine Cycle (ORC) plant totalling 400 MW. There are many examples of both plant types in New Zealand. One of the four units at each station would stay fully loaded, to keep the wells flowing in a stable, hot condition. This configuration allows an additional 300 MW to be available for dry year back-up generation.

Conventional flash steam plants bring steam through a steam turbine, which turns a generator connected to a direct contact condenser, where the steam is condensed by sprays of cold water, and non-condensable gases (NCGs) are extracted. The steam condensate is removed to a cooling tower, where it is cooled and can then be reused as cold water spray in the condenser.

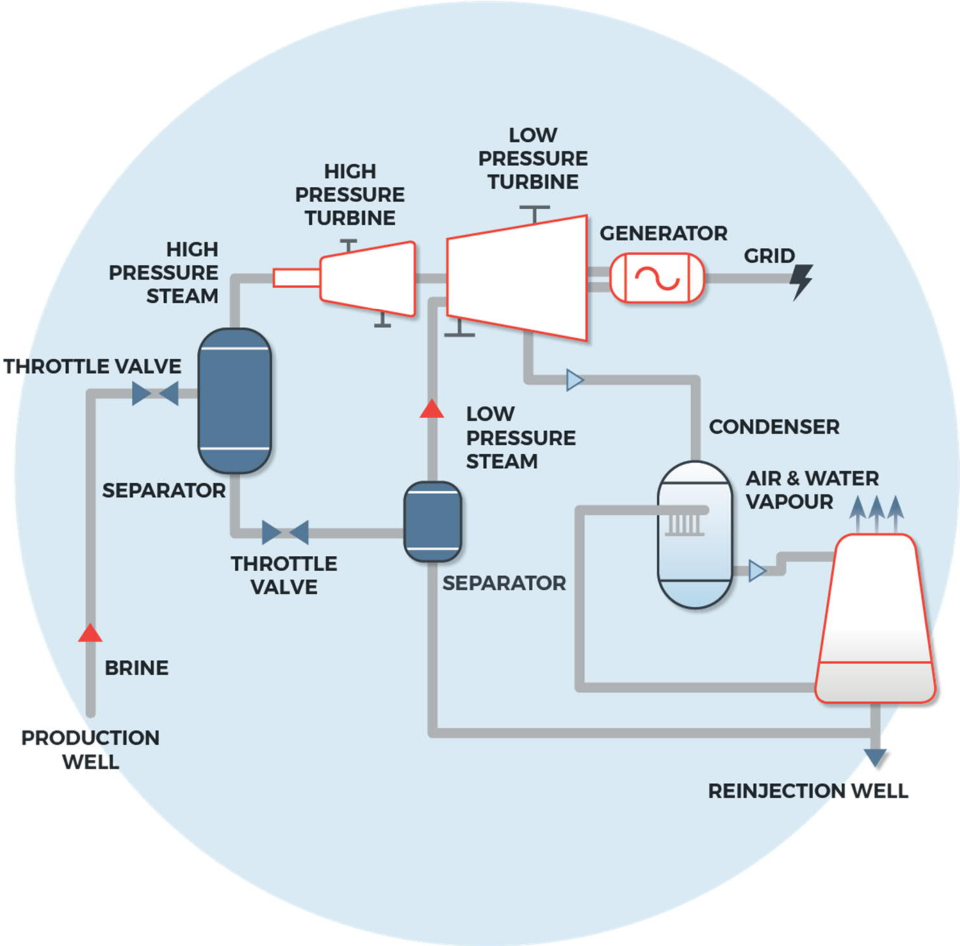


Figure 5-2: Condensing Steam Turbine (Double Flash Example) Schematic

Surplus condensate is then pumped to reinjection wells. In typical New Zealand plants, NCGs are vented into the cooling tower plume and dispersed into the atmosphere, however, the NZ Battery Project assumes that NCG (including CO_2) reinjection will be used.

Binary cycle ORC plants would also be deployed as part of the proposed base case. While ORC plants can be designed to take two-phase flow directly, plants in New Zealand typically have separators to allow separate processing of steam and brine. In some cases, the flows are recombined in heat exchangers that feed heat to the same turbine-generator, while in some cases they act as bottoming units, taking brine only and using that as the heat source.

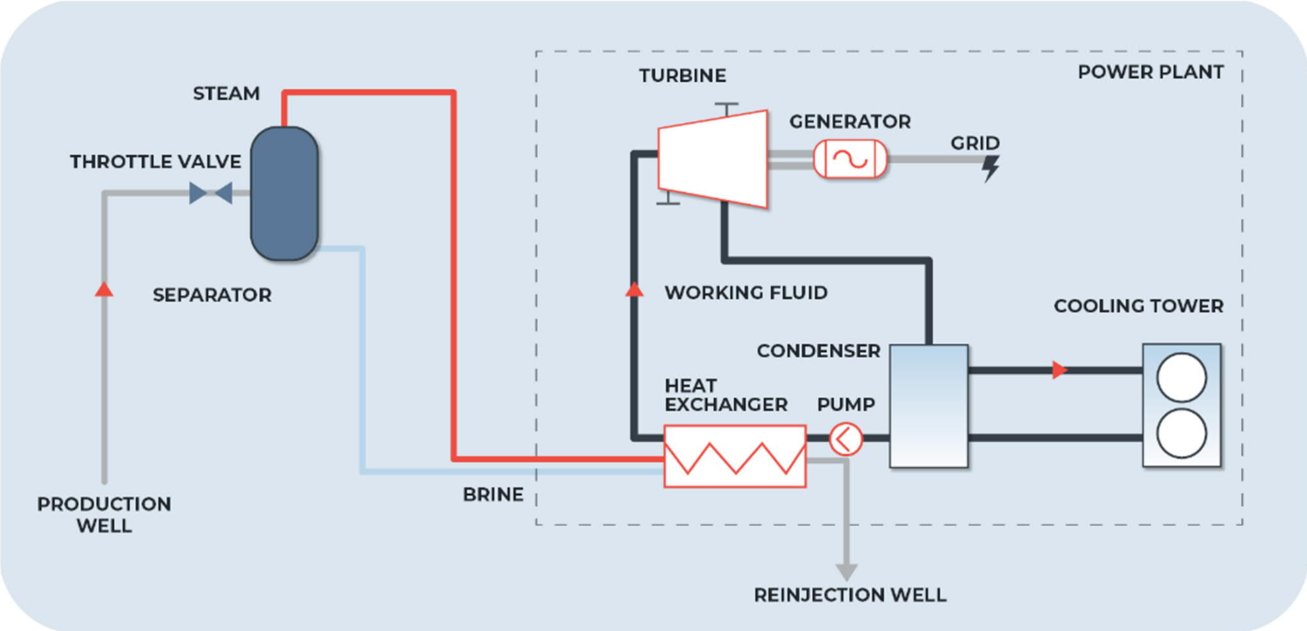


Figure 5-3 - Binary ORC Plant Schematic

In the typical New Zealand ORC plant, when steam is fed to an ORC, one of the heat exchangers will act as a steam condenser, from which NCGs are extracted. These plants are called binary cycle plants, because they use a secondary working fluid (a low boiling point hydrocarbon) passing through an arrangement of turbine, condenser, pump and heat exchanger in a closed cycle. The ORC condenser is a fin fan condenser (essentially a giant car radiator) with working fluid running through the fins and air blown vertically between the fins. Conventionally, the NCGs from the condensed steam are fed to the cooling tower plume for dispersal, as for the flash steam plant. The ORC plant proposed for the NZ Battery base case assumes that NCG reinjection will be used.

A further variation involves hybrid systems (also called Geothermal Combined Cycle Units, GCCUs), which take steam through a steam turbine first, then use binary ORC units to act as steam condensers and bottoming units on the separated brine system. We recommend that procurement processes enable OEMs to offer the most suited technology option, or a hybrid of options, determined on a site-by-site basis.

ORC units tend to be modular, with some units of 5 MW or so in size, up to Ormat units that can generate 30 MW from a single unit. Turn down capability of ORC units is still being confirmed by manufacturers, though initial communications indicate that the proposed base case flexibility could be provided. In the proposed base case, the current assumption is that no turndown will be required, as only one in four units will operate in a normal year, with remaining units mothballed. Turned down operation of any unit is known to be less efficient than full load operation, so is undesirable in the long term. The power plants are intended for installation by 2030, and expected to have a lifetime exceeding 30 years, while steam fields (with appropriate drilling and connecting of makeup wells) are indefinitely sustainable.

5.3.3 BASE CASE OPERATION

The proposed base case provides 300 MW of additional dry year NZ Battery capacity, in addition to baseloaded 100 MW. This would generate just over 0.6 TWh over three months, or more if run over longer periods e.g. around 1 TWh over six months, if required. However, with the Battery function intended for dry year backup duties vs long-term baseload, consents linked to the long-term sustainability of the reservoir could limit operations over multiple years. It is proposed, therefore, that the plant runs at several states of steady load, depending on required NZ Battery duty.

Geothermal Piping Loops, Ngatamariki Geothermal Power Station.
Photo credit: Chris Sisarich, NZ Story

To ensure the optimal equipment performance curve efficiency, the final sizing and technology selection of plant and auxiliaries would be optimised against the base case operation, which includes tailoring plant parameters for location specific weather and meteorological conditions.

The plant would need to be permanently embedded into the transmission system. This will create similar challenges to other forms of generation, including the need for grid reinforcement, where required.

In steady state mode, post-start-up or shut-down, operator requirements would be minimal, as per existing geothermal stations. There may be advantages in contracting out the operation and maintenance of the multiple NZ Battery plants, and associated reservoir monitoring and management functions, to a third party.

5.3.4 INFRASTRUCTURE REQUIREMENTS

Geothermal technology is tried and proven, though each field has unique characteristics. The project would use both conventional steam condensing plants and Organic Rankine Cycle (ORC) plants for generation. A requirement at the design stage would be to include engineering design of operational and maintenance enhancements, to enable added flexibility to allow turndown in the event of load-following requirement. This will require additional flexibility, in terms of gas extraction, pumping and cooling tower operation.

STEAM FIELD FACILITIES TO LINK RESERVOIR WITH THE STATIONS

Geothermal energy is generally used where it is found. In some countries e.g. Iceland there can be tens of kilometres between field and application, however, in most New Zealand fields, the distance between production wells, station (and/or direct use application) and reinjection wells is less than ten kilometres.

Production and reinjection wells would be of conventional design, but using 13 $^{3}/_{8}$" diameter production casing, which is taken as the new standard well design. While costs are greater than the older 9 $^{5}/_{8}$" diameter production casing wells, this is more than offset by the additional well capacity expected for the better wells, thus reducing the number of wells required and drilling costs overall. 15% surplus steam capacity is assumed as a start-up requirement, to allow for rundown, with make-up well drilling at sufficient intervals. The number of production and reinjection wells will be determined by the peak requirements of the stations and the success ratios during drilling (assumed to average 70% across the programme for each field in the portfolio).

Two-phase pipework would deliver a steam/brine mix to separators. The piping delivering two-phase geothermal fluid from the production wellhead is sized to keep both phases entrained. The ideal flow regime is annular, where a liquid film flows on the pipe wall (forming an annular ring of liquid) while the steam flows as a continuous phase in the centre of the pipe (and is particularly stable). If the two-phase lines are sized to maintain annular flow at 100% capacity, it is highly likely to be oversized for turned down capacity, with a risk of an unstable slug flow regime resulting. This may require the use of smaller diameter piping between the wellheads and separators than conventional plant, or multiple lines with an option to put some lines out of service during normal years. In the overall concept, these will have only a minor impact.

Steam lines take fluid from the separators to the station, while brine lines take fluid from the separators to the reinjection wells. Steam and brine pipework would be of conventional design, though special considerations may be needed to avoid long dwell times for the fluid in brine lines, especially if supersaturated with silica. A positive feature of the low load condition will be lower associated pressure loss over the lines.

Separators separate steam (and NCGs) and brine. Effective separators that deliver high quality dry steam are important for the operation of steam turbines. They are also used by binary cycle ORC plant manufacturers, to avoid the potentially damaging effects of unstable flow on heat exchangers and provide greater opportunity for efficient design.

The ability to operate the steam field at 25% load may require modifications to typical conventional separator design and location. While separators are normally sized for maximum superficial steam velocities, there can also be lower velocity limits that influence the effectiveness of the separators. If separators are sized as single units for full load capacity, they could be too large for the turn down rate. Consequently, a choice has been made for two vessels of 50% capacity to be installed on each field, rather than a single unit. An alternative could be to use horizontal separators, rather than the conventional New Zealand choice of vertical Webre units.

In a normal year, the redundant separator and two-phase line (which might otherwise experience undesirable slug flow if turned down excessively) would be back-fed with minor quantities of steam, which would be bled to atmosphere in order to minimise shut-down corrosion risk.

5.3.5 OPERATIONAL FLEXIBILITY

The portfolio approach, coupled with the multiple units on each field, should allow a high degree of flexibility. While operational difficulties could be experienced on one field, other geothermal battery fields will still be available. Similarly, if one of the four units on a field during a normal year needs servicing, then one of the mothballed units can replace it. Maintenance can be staggered, to help manage peak personnel requirements, and it should be possible to rotate use of units so that no single unit gets more usage than another. This also has benefits of streamlining inspections and servicing/rotation of spares and auxiliaries, as preferred by equipment manufacturers.

It is recognised that capital cost could be reduced if the station consisted of a 25% unit and a 75% unit rather than 4 x 25% units. The cost effect of retaining the 4 x 25% flexibility is estimated as a 6-7% capital cost penalty.

The option of short-term load following flexibility is a potential secondary benefit of a geothermal battery discussed in 5.6.2 Other Insights. There may be challenges with flexible subsurface well operation but, in particular, the ORC Binary generating plant offers a strong opportunity to be able to deploy as a solution with additional flexibility for short-term, load following operation.

5.3.6 CO_2 EMISSIONS AND RESOURCE ASSESSMENT

The geothermal base case has an energy output of 32 TWh over the 35-year lifetime. Based on an embedded emission factor of 10 g CO_2-e/kWh, the total carbon emissions output is approximately 320 kt CO_2-e, prior to the plant becoming operational e.g. for plant transport to site, or embedded in the concrete used for foundations.

The geothermal base case includes NCG extraction and reinjection technology with the assumed capacity to extract (50%) of emissions produced during operation and reinjecting back into the geothermal reservoir.

Prior to carbon extraction and reinjection, the total operational carbon emissions are estimated at 72 kt CO_2-e during a dry year, 41 kt CO_2-e during a normal year and 1,650 kt CO_2-e over the 35-year lifespan of the plant. Based on the assumption of 50% capacity to extract and reinject emissions back into the geothermal reservoir, the operational emissions are estimated at 36 kt CO_2-e during a dry year, 20.5 kt CO_2-e during a normal year and approximately 850 kt CO_2-e over the 35-year lifespan of the plant.

The main potential land impact resulting from operation of the geothermal power plant is subsidence. In practice, this is avoided through the use of brine and condensate reinjection. The most important potential impacts on the aquatic environment are associated with the management and disposal of wastewaters, notably geothermal brines, which are commonly disposed of by reinjection into wells, where they can contaminate groundwaters or by storage in holding ponds, which can leak into surface waters. The process of reinjection back into the deep reservoir, away from the production area, counters all of these concerns.

During construction, there is a large amount of water required for well drilling. As an indication, during the construction of other New Zealand geothermal power plants, drilling of the wells can use approximately 150,000 litres of non-potable water per day. Once operational, water requirements are minimal.

5.3.7 ALTERNATIVES TO BASE CASE

ALTERNATIVE OPPORTUNITY – CO-OPERATION WITH EXISTING GENERATORS

If commitment to co-operation and partnership is made to a geothermal NZ Battery Project, existing generators could help implement additional capacity early, thus augmenting available energy beyond this base case. This could be valuable in the early stages, while other options are being constructed or deployed.

Existing generators know the process from exploration through to consenting and development and are already set up to own, operate and maintain steam fields and stations. In many cases, they hold the key commercial information that can unlock a field for expansion. Generators may also hold unused consents or be about to create them. The following are desktop observations, with any advancement requiring cultural, commercial and technical evaluation. These examples are provided purely for illustration purposes and do not imply any specific intention in relation to the NZ Battery Project.

Negotiations

- *Direct Use Benefits* - If fields have direct use applications on them, in parallel to (rather than cascaded from) generation, these could instead be used to keep the wells flowing, avoiding the need for the baseloaded “one out of four” fourth unit on a field. In this scenario, all geothermal power plant investment would result in additional dry year capacity. In a dry year, the direct use could keep operating in the same manner that the baseloaded quarter of field station capacity would have operated, avoiding investment in that unit.

These options alone could add another 200 MW of Battery capacity in a relatively short timeframe (equivalent to an extra 0.4 TWh over three months).

ALTERNATIVE OPPORTUNITY – LOW BASE LOAD FACTOR HELPING TO BRING FORWARD GENERATION

There is an opportunity to provide both a conservative safety factor and a means of potentially bringing forward baseload generation beyond the NZ Battery. The capacities in Table 5.1 above assume a 95% load factor, while the geothermal battery may be operating at around 25% over a period of several years. This would allow the building of three or more times the capacity at the low load factor from a sustainable energy use basis, since sustainable energy use is based on MW x time rather than peak power generated. Normally, as indicated in the table, generation would be built in a staged manner to confirm the carrying capacity of the field. For example, if a field is envisaged as an ultimate 100 MW baseload field through multiple stages with an initial approval of 33 MW baseload, the geothermal battery development would have 4 x 25 MW low-load units from the outset, to minimise the risk of eventual overbuild on the field. The wells and steam field would still have to be developed to meet the peak 100 MW of load through well step-outs and infill drilling, and this would occasionally be tested at this level during full load NZ Battery operation. Information could then be used to model response and confirm a greater overall capacity, enabling firm plans in the early 2030’s and potentially bringing forward additional baseload capacity by as much as twenty years (compared with forecasts for the MBIE generation stack).

Other upside options for consideration could then include building additional capacity on the field, increasing the available battery size, or shifting some NZ Battery units in future to baseload duty. NZ Battery units would effectively act as large-scale test facilities of the ultimate field capacity.

5.4 RISKS AND OPPORTUNITIES

A detailed assessment of the risks that are relevant to the selected base case (and alternatives) has been undertaken, as outlined in Section 2.3. For several key risks, specific analyses were undertaken.

5.4.1 RISK ASSESSMENT SUMMARY

A summary of risks and opportunities for the geothermal technology is provided in the tables and descriptions below. The tables show the number of extreme, high, moderate, and low opportunities and risks, before and after treatment/mitigation. Refer to the Risk Register within Appendix G for a detailed analysis of the risks, opportunities, assessment, and mitigation.

Geothermal Opportunities		
	Untreated	Exploited
Extreme Opportunities	0	3
High Opportunities	5	12
Moderate Opportunities	8	1
Low Opportunities	3	0
Total	16	16

TECHNOLOGY OPPORTUNITIES

- Opportunity to provide a revenue stream from silica and other minerals removed from geothermal resource. **Exploitation**: This is an emerging technology to be investigated further and could be used during periods when geothermal power is not being utilised. **Exploited Opportunity Rating**: High.

MARKET AND ECONOMIC OPPORTUNITIES

- Opportunity for the investigation work on this project to improve available knowledge on geothermal resources, which could enable faster development of sites by the market for base load generation. **Exploitation**: Partner with landowners and power firms in investigations, with sharing of information and agreements on fields to be developed. **Exploited Opportunity Rating**: High.
- New industrial or commercial operations that could utilise steam fields, heat or power. **Exploitation**: **Exploited Opportunity Rating**: High.
- Opportunity for New Zealand to develop new technology or geothermal plant operation techniques. **Exploitation**: Consider phased implementation to allow trials of new technology and methods, develop a geothermal capability register that highlights key NZ skills. **Exploited Opportunity Rating**: High.

- Opportunity for the geothermal battery solution to be developed by the private market. **Exploitation**: Consult with power generation firms, assess market implications and potentially develop as part of procurement strategy. **Exploited Opportunity Rating**: High.

TECHNICAL OPPORTUNITIES

- Opportunity for New Zealand to develop technical expertise and capability in new technologies. **Exploitation**: Use the project to further advance trials/technology, procurement strategy to include learning and development for NZ based people, consider phased implementation. **Exploited Opportunity Rating**: High.

- Opportunity to reduce load factor assumed in the base case to provide increased capacity. **Exploitation**: Review load factor at next stage of the project, find balance of well field risk versus battery operation approach. **Exploited Opportunity Rating**: High.

- Opportunity to provide short-term load following, in addition to dry year backup supply. **Exploitation**: Consider plant requirements to offer flexibility and any maintenance implications, consider associated risks. **Exploited Opportunity Rating**: High.

ENVIRONMENTAL OPPORTUNITIES

- Opportunity to utilise carbon capture technology. **Exploitation**: Investigate the status and future planning of geothermal carbon capture trials with geothermal power plant OEMs and operators to further refine and update the expected technology readiness levels by 2030. **Exploited Opportunity Rating**: High.

TE AO MAORI OPPORTUNITIES

- Opportunity for partnerships with local iwi to develop the battery project. **Exploitation**: Selection of sites developed in partnership with Iwi, establish effective and best practice Iwi engagement strategy, partnership based decision making approach with Iwi. **Exploited Opportunity Rating**: Extreme.

- Economic and social opportunities for Māori groups and communities related to the potential development of geothermal sites on Māori lands. **Exploitation**: Identify opportunities to support local businesses and industries, establish effective and best practice Iwi strategy, partnership based decision making approach with Iwi. **Exploited Opportunity Rating**: High.

- Opportunity for local job creation in construction and operation. **Exploitation**: Develop a procurement strategy that values local recruitment and skill development for Māori communities. **Exploited Opportunity Rating**: High.

CULTURAL AND SOCIAL OPPORTUNITIES

- Opportunity for local job creation in construction and operation. **Exploitation**: Develop a procurement strategy that values local recruitment and skill development for local and/or New Zealand based resource. **Exploited Opportunity Rating**: High.

Geothermal Risks		
	Unmitigated	Mitigated
Extreme threats	24	0
High threats	14	13
Moderate threats	0	24
Low Threat	0	1
Total	38	38

TECHNOLOGY RISKS

- Risk that sufficient technical expertise is limited in New Zealand, preventing implementation of the project at the required scale, in the required timeframe. **Mitigation**: Develop a procurement strategy that tests the market, consider phased implementation, utililise international expertise if required. **Mitigated Risk Rating**: High.

MARKET AND ECONOMIC RISKS

- Risk that appropriate sites to develop the geothermal battery project are not available, leading to challenging consenting processes, reduced performance, delays and increased costs. **Mitigation**: Feasibility study allows for sufficient sites not currently proposed for development (back of stack). **Mitigated Risk Rating**: High.

TECHNICAL RISKS

- Risk that long-term operation of the wellfield in a schedulable manner is not feasible due to sub-surface issues. **Mitigation**: Base case includes operation at a low load/turndown in non-dry years, operation at 25% full load acceptable with technical solutions and mitigations for this risk to be researched and developed, and with more frequent well maintenance. **Mitigated Risk Rating**: High.

ENVIRONMENTAL RISKS

- Risk that impact on water courses, flora and fauna from construction and operation of new geothermal plants is negative. **Mitigation**: Design avoids discharges to air, water, land through use of reinjection, or where not possible to avoid, discharges result in no change to the baseline environment, NCG capture. **Mitigated Risk Rating**: High.

TE AO MAORI RISKS

- Use of geothermal resource (taonga) in the process negatively impacts Te Ao Māori. **Mitigation**: Establish effective and best practice Iwi engagement strategy, partnership based decision making approach, application of Mauri Model cultural monitoring in the assessment of sustainable resource management. **Mitigated Risk Rating**: High.

CULTURAL AND SOCIAL RISKS

- Risk that the large investment in geothermal battery operation is perceived as being highly inefficient and cost-ineffective. **Mitigation**: Base case proposed base load operation to generate power in non-dry years, options to increase benefits through increased generations in peaks etc to be explored, public engagement strategy. **Mitigated Risk Rating**: High.
- Risk of negative operational impacts (noise, odour, vibrations) on communities. **Mitigation**: Robust site selection process involving assessment of operational impacts on communities, establishing effective and best practice community engagement strategy. **Mitigated Risk Rating**: High.
- Risk of negative construction impacts on communities. **Mitigation**: Robust site selection process, selection of sites that are existing industrial sites where construction impacts are reduced, establish effective and best practice community engagement strategy. **Mitigated Risk Rating**: High.

CONSENTING RISKS

- Risk of the project not meeting the requirements of the Resource Management Act. **Mitigation**: Robust site selection against RMA requirements among other criteria, appropriate discussions with affected parties, designs to mitigate specific hazards/risks and enhance values where possible. **Mitigated Risk Rating**: High.

5.5 COSTS

The base case involves building a total generation capacity of 400 MW across multiple sites. In the normal years, one out of 4 x 25% capacity plants will run, with mothballing of the remaining 3 x 25% (75%). During dry years, the remaining 75% capacity will be brought online.

The Capital and Annual Operational Expenditures (Capex and Opex) for this project were obtained using a bottom-up methodology, where the cost estimates associated with several separate geothermal sites were calculated and summed up as one lump sum.

5.5.1 COST ESTIMATE

Feasibility Study Level Cost Estimates (Class 4 estimates to AACE guidelines i.e. -30% / +50%). Refer to Section 2 Approach for details of the Cost Estimate approach.

A more detailed breakdown and derivation is provided in Appendix H and cost estimate spreadsheet that accompanies this report.

Table 5-2: Feasibility study level cost estimates (Class 4 estimates to AACE guidelines, i.e. -30% / +50%).

Estimates excluding revenue			
Geothermal Total Lifetime Class 4 Cost Estimate (Excluding revenue)			
	Base cost	50th Percentile (approximate)	90th percentile (approximate)
Total Capital Cost (Unescalated)	Commercial Information		
Total Capital Cost (Escalated)			
Total Capital Cost (Escalated at present value)			
Operational costs (2030-2065) Unescalated			
Operational costs (2030-2065) Escalated			
Operational costs (2030-2065) Escalated and at Present Value			
Total Cost (unescalated and not discounted)			
Total Cost (escalated and not discounted)			
Total Cost at PV ($M)			

Estimates including revenue			
Geothermal Total Lifetime Class 4 Cost Estimate (including revenue)			
	Base cost	50th Percentile (approximate)	90th percentile (approximate)
Total Capital Cost (Unescalated)	Commercial Information		
Total Capital Cost (Escalated)			
Total Capital Cost (Escalated at present value)			
Revenue (unescalated and not discounted)			
Revenue (escalated and not discounted)			
Revenue PV			
Total (unescalated and not discounted)			
Total (escalated and not discounted)			
Total Cost at NPV ($M)			

5.5.2 KEY ASSUMPTIONS / BASIS OF ESTIMATES

SOURCE OF COST INFORMATION AND CONTINGENCY ASSESSMENT

Past project and OEM cost estimates have been used, with contingency applied based on confidence levels in the source information. WSP holds, and has access to, a good level of information on costs for the delivery of geothermal plants. This has influenced the setting of contingency and funding risk, to obtain the expected 90th-percentile estimates.

GENERAL

- All expenditure values are stated in 2022 NZ dollar terms.
- Historical figures used in building up cost estimates have been escalated using the CPI index
- Inflation (escalation) has been applied to all costs after 2023 using a rate of 3%, which reflects the expected long-term average and not the current rate of inflation
- A discount rate has been applied to future costs from 2023 using the New Zealand Treasury rate (as at August 2022) for Infrastructure (Water and Energy) and Special Purpose (Single-Use) Buildings of 5%).
- Goods and services tax is excluded.

Construction timeframe:

- Build across five sites staggered over six years.

DEVELOPMENT COSTS

The sum of the items below approximates Commercial Information the estimated station physical work costs combined Commercial Information of the estimated steam field physical works.

- **Investigation** costs are for the design option development costs including site optioneering and concept designs, as well as site field investigations.
- **Consent** costs are for the preparation of applications for consents, licences and designations. This includes allowance for processing of applications in minimum timeframes.
- **Design and Procurement** costs include the development of designs for the purpose of consenting (specimen designs to go to an engineer), procure and construct contract (EPCC) or design and construct. Design costs following the award of an assumed EPC contract are included within the capital cost estimates.
- **Property** will likely be a lease cost and could be converted into a shareholding in the future. An allowance Commercial Information has been made for each of the assumed five sites in the base case, noting that these costs could vary depending on the specific site location.

CAPITAL COSTS STEAM FIELD

- **Steam field Construction – Civil** – Lower contingency as cost is conservative.
- **Steam field Construction – Mechanical & Electrical** - Higher potential for cost and quantity variance in steam field mechanical and electrical items than civil.
- **Steam field Construction – C&I** - Controls and instrumentation equipment.

- **Wells (including failures + contingency factor)** - Average variance in well cost over the number of projects. Four exploration wells per site in years 2-3, balance years 4.5-6. Other factors were:
  - Gross plant MW output increased Commercial Information to provide margin for run-down before next lot of make-up wells are drilled and connected
  - No. of production wells required = round up (Gross MW output / 16 MW)
  - Ratio between number of production wells to reinjection wells assumed to be 2:1
  - Reinjection wells assumed to be same size as production wells
  - Failure factor for wells assumed to be 30% (3 out of 10 wells are unsuitable, so 10 wells drilled for every 7 required)
  - Each well (production and reinjection), including failures, assumed to cost Commercial Information
  - Mobilisation/Remobilisation cost estimated Commercial Information per site for 75 MW plant, Commercial Information per site for 100 MW plant
  - Total well cost = total production well cost + total reinjection well cost + mobilisation/remobilisation
  - Make-up drilling cost assumed Commercial Information of total well cost/year
- **Reinjection Wells** - Roughly one re-injection well for every two production wells
- **Mobilisation/Remobilisation** - One rig for plants 75 MW or smaller, two rigs for plants 100 MW or bigger, assume five sites.

CAPITAL COSTS STATION

- **Station Construction – Civil** - Can vary significantly due to sites, consents and designs, all of which are unknown. Commercial Information of total
- **Station Construction - Mechanical & Electrical** - Lower contingency applied, as base cost is a high value item with higher level of certainty.
  - Gross MW for ORC plant obtained by dividing net MW by Commercial Information
  - Gross MW for condensing plant obtained by dividing net MW by Commercial Information
- Station Construction - Control & Instrumentation - Higher contingency acceptable due to lower cost
- Gas Reinjection Plant (NCG) - Emerging tech, so higher contingency due to greater uncertainty.
  - Average CO_2 equivalent assumed to be 52 g/kWh (i.e. net of embedded carbon)
  - Estimated cost Commercial Information process 130 tonnes of CO_2 per day, but costs have been scaled by a power law to create estimates for the range of development sizes.
- **Transmission connections to grid** - for power plant side of connection, assumed to Commercial Information per site. Potential for significant variance in transmission distance.

- **Preservation Plant** – For mothballing of above-ground steam field and power plant equipment in the transition between dry and non-dry years. Other factors are:
  - Preservation Capex for ORC station assumed Commercial Information of station construction and equipment cost
  - Preservation Capex for condensing station assumed to be Commercial Information station construction and equipment cost
  - Preservation Opex assumed to Commercial Information preservation Capex for both ORC and condensing plants.

OWNER'S COSTS DURING DEVELOPMENT AND CONSTRUCTION PHASES (UPFRONT)

- Calculated Commercial Information physical works costs. This is expected to include owner costs during development phase such as management fees, financing, setting up management company and setting up supply contracts.
- When this item is combined with the Development item, they equate Commercial Information the physical works cost.

OWNER'S COSTS DURING OPERATIONAL PHASE

- An allowance of Commercial Information has been made in the base estimate for the running of management company overseeing operation of the New Zealand Battery.

OPERATIONAL

There are two separate Opex costs for each site. One for the normal years, where stations operate at 25% capacity, and another for a portion of the dry years, where the stations operate at 100% capacity.

1. Dry Year Opex:
   a) Make-up Drilling Cost
   b) Preservation Implementation Cost
   c) Fixed Station Cost
   d) Fixed Steam field Cost
   e) Variable Cost in Dry Year.

The applied methodology involved finding the following:

1. Gross MW Capacity
2. Capex – Establishment, Steam Field, and Station Costs
3. Split Steam Field and Station Capex into
   - Other Station Capex – Transmission, Preservation, Gas Reinjection
   - Other Steam Field Capex – Wells, Mobilisation/Remobilisation, and Failure Factor
4. Opex – Dry Year
5. Opex – Normal Year.

CARBON COST

- Based on 50% effectiveness of NCG reinjection Commercial Information in 2020, Commercial Information 2035, Commercial Information 2050 and Commercial Information 2065 (MBIE assumptions book). Costs extrapolated in between these points.

DECOMMISSIONING

- Decommissioning cost Commercial Information the capital cost.

REVENUE

- **Power sale (non-dry year)** – 100 MW of turned down plant running at 0.9 capacity factor, selling at average Commercial Information due to the turned down geothermal plant running continuously year-round.

- **Power sale (dry year)** – 400 MW of full battery running for three months at 1.0 capacity factor, selling at Commercial Information + 9 months of above mode.

5.5.3 *OTHER PROJECT BENCHMARKS*

For the geothermal technology, there is a good level of cost data from existing projects, as outlined in the table below.

Example Project Comparisons					
Project Name	Type/Scale of Project & Location		Date Construction Completed	Other Notes	Cost
Ngāwhā 1	ORC plant, 2 units x 5.5 MW gross, 9.3 MW net, about 80GWh/year	Ngāwhā geothermal field, Northland	1998	Public EPC station cost of US$17m published in 1997	US$17m
Ngāwhā 2	ORC plant, 1 unit x 20MW gross, 17MW net, about 120GWh/year	Ngawha geothermal field, Northland	2008	Public total cost of NZ$77m in 2007	NZ$77m
Kawerau	Double Flash, 1 unit x 110 MW gross, about 100 MW net, about 800GWh/year	Kawerau geothermal field, Central North Island	2008	Total project cost from MRP news release September 2008	NZ$300m
Te Mihi	Double Flash, 2 units x 84 MW gross, 159 MW net, about 1,385GWh/year	Wairakei geothermal field, Central North Island	2014	Total project cost from Contact article in Power Magazine August 2013	NZ$623m

Example Project Comparisons					
Project Name	Type/Scale of Project & Location		Date Construction Completed	Other Notes	Cost
Ngāwhā 3	ORC plant, 1 unit x 31.5MW gross, about 28 MW, about 120GWh/year	Ngawha geothermal field, Northland	2018	Station cost from Ormat media release 2017, total cost from NZ Herald article Aug 2017	Station US$50m, total cost NZ$160m

5.6 SUMMARY

5.6.1 GEOTHERMAL NZ BATTERY OPPORTUNITY

Geothermal energy for a NZ Battery solution presents a unique opportunity, as its energy is inherently stored and does not need to be "recharged" like other technology options. The base case has been designed around an appropriate feasible solution for the NZ Battery, which is to provide 300 MW of additional generation, corresponding to 0.6 TWh over three months. However, it also has potential to continue running and provide more dry year back-up energy, as required over longer durations, with minimal additional cost.

Geothermal is a well proven technology in New Zealand, with many sites already in operation. The risks for this solution are mainly limited to the long-term operation of the wellfield in a schedulable manner. While not considered high risk, it is non-standard operation and there is limited track record for this kind of operation. CO_2 extraction and reinjection is used in the base case to minimise surface environmental effects and to maintain reservoir pressure. This has also not been done before, but is also not considered high risk, with trials already being carried out to demonstrate commercial feasibility. To account for this risk a nominal reinjection effectiveness allowance of 50% has been included in the operational carbon emissions assessments and cost estimates.

A challenge with geothermal is the constraint on how much can be built before pushing against the limits of what would otherwise be built, given geothermal is an important part of New Zealand's "stack" of future renewable generation projects (unlike hydrogen and biomass, where nothing at significant scale exists, or is currently in advances stages of development). For this reason, there is an upper limit on what can be used to provide a stand-alone battery.

The 0.6 TWh solution proposed would involve developing multiple geothermal sites, which also adds some challenge and complexity to this solution. While considered achievable, based on previous country development rates and the ability for international development support, there will still remain some risk around development timeframes due to the quantities of drilling required and the technical expertise available. The developments will also require significant consultation with stakeholders, including local iwi, to ensure the co-operation of kaitiaki and incumbents. This could slow down development timeframes but ultimately could provide economic and social opportunities for Māori groups and communities.

As part of base case design, efforts have been made to avoid oversizing the development for the field. Installed capacity has been limited to the expected baseload capacity when the field is fully developed. An implication is that, once a field has been operated and the sustainable capacity is proven, it may be possible for all or some of the geothermal Battery plant to be transferred to normal market operation. The Battery design both enables a valuable function in terms of dry year relief, while potentially advancing geothermal generation for normal market operation by decades. In this regard, it offers a relatively safe, future-proofed option for New Zealand.

5.6.2 OTHER INSIGHTS

OPTIONALITY OF SWITCHING TO BASELOAD RENEWABLE GENERATION

Geothermal offers the optionality for some or all geothermal NZ Battery plants to be switched in the future to run as a source of cost-effective, renewable baseload generation. This provides an option for additional economic and energy benefits from the asset, if New Zealand's future generation mix and dry year risk profiles allowed this change. The geothermal solution may, therefore, provide a no regrets option, in that it could bring forward otherwise undeveloped generation plant, while deferring the need to build a large-scale energy storage scheme. This could "buy time" while other less developed technologies (e.g. green hydrogen) mature. It may also remove the need, or minimise the size, of any future energy storage scheme, due to a critical mass of Variable Renewable Energy (VRE) sources being built in future.

By drawing on "back of the stack" generation, risk of interfering with generation that might otherwise be developed for normal market function can be avoided. Operation of some of the geothermal battery stations around 2030 will enable these fields to be tested at high load with the field response then feeding into consents for further development, potentially bringing forward other "back of the stack" normal market generation by up to 20 years. These future additional capacity developments would have the option of being deployed as conventional baseloaded plant, or increasing the size of the NZ Battery.

SHORT TERM LOAD FOLLOWING, DISPATCHABLE OPERATION

Geothermal generation plant does have some flexibility. The short-term, load following optionality could be enabled by switching on all or some portion of the NZ Battery plants, with wellhead master valves opened up correspondingly (e.g. all wellhead valves fully open and all 4 x 25% plants running). As well as full load energy dispatch, this would also provide the ability for shorter-term load following, where the plants could be ramped up and down more rapidly (approximately 30% to 100% load over an order of minutes), by bypassing the plant and returning hotter fluid to reinjection. The ORC Binary plants (that make up nominally half of the base case) would be the most suitable geothermal technology to also provide short-term load following. If desired, these plants could be left running at 30% load, with hotter bypass fluid being sent to reinjection for as long as required. This bypassed fluid would need to be fully condensed to allow pumping or gravity injection back into the reservoir. This may require supplementary surface takes of water, while multiplying the required number of reinjection wells. Note, however, there would be a certain level of energy wastage penalty by doing so, as the wellhead master valves would still fully open at this stage. Plant would still need to operate within the bounds of limited take and discharge consents, such that every MWh of bypass would represent a permanently lost MWh from the geothermal battery.

It is estimated that the costs of implementing a solution that more readily permits short-term dispatch would be in the order Commercial Information of total capital cost.

However, in the NZ Battery context, this may not be the most optimal option, when considered against New Zealand's potential future generation mix. It may be more optimal, as a dry year response, to switch on the geothermal NZ Battery and provide electricity continuously for, say, three to six months, then use other technologies for short-term load thereafter (e.g. hydro generation or Battery Energy Storage Schemes (BESS), if required).

ADDED VALUE MATERIALS EXTRACTION (SILICA, LITHIUM)

Large flows of geothermal brine bring up minerals from the reservoir, including silica and lithium. When appropriately refined, these products have commercial value, with New Zealand company Geo40 already on this extraction/commercialisation path. Extraction of silica is required before the other minerals can be accessed, but the benefits of its removal are threefold: 1) the silica is converted to a saleable product, 2) fouling of lines and equipment is significantly reduced, improving operating life of steam field infrastructure and 3) more heat can be taken from the fluids without the same risk of scaling, allowing more power generation from the same fluid, effectively lowering the unit rate ($/MWh). It can also lead to savings on costs associated with other methods of fouling prevention, such as acid dosing, as it is no longer required.

If lithium can be commercially extracted, then this has potential as a source for electric vehicle battery production, without the potential environmental damage associated with large scale mines. Extensive laboratory research has been carried out on this process and Geo40 is now building a pilot plant to commence scaled up trials. Work has also started on extraction of other minerals and metals, including boron, antimony and caesium.

There is an opportunity for this innovative technology to be incorporated into the implementation of a geothermal NZ Battery Project, providing additional economic value streams, together with associated benefits of enhancing New Zealand's industry knowledge.

ADDITIONAL GEOTHERMAL RESOURCE CONSIDERATIONS

The recent geothermal stack update (Lawless et al, 2020) based plant capacities on a high load factor (~95%). As capacity in this methodology is based on stored heat, it follows that if the load factor is reduced to, say, a third, then the installed capacity could be increased by a factor of three or more, depending on the expected future load pattern.

Energy required for the NZ Battery function remains stored in the geothermal reservoir. Regional Councils have optimised this storage, by allowing takes and discharges of fluid to be averaged over a year, essentially allowing a certain amount of energy in TWh of generation per year. In practice, the NZ Battery function of geothermal would require these takes and discharges to be averaged over several years, but the low load factor will allow peaks in generation several times the normal baseload levels.

While low load generation allows multiplication of capacity over baseload capacity, for the purposes of this study a decision has been made to limit capacity on any field to the expected eventual baseload capacity of the field, once all stages are completed. This expected capacity may be two or three times the equivalent baseload capacity initially approved by Council or the Environment Court.

The initial operation of the geothermal battery on a field will test the field, with reservoir monitoring and modelling then allowing developers to firm up actual sustainable capacity under various future expanded operating scenarios. However, it is likely that proven and expected capacities will be similar.

On this basis, if it was decided in future that Battery operation was no longer required on a field, then the plant could simply be transferred to baseload operation without delay, with relatively low chance of overbuild.

A unique feature of NZ Battery operation, not built into conventional reservoir stored heat considerations, would be the effect of the normal low load operation compared to peak load. This long cycle is referred to as “heat grazing” (Bromley et al, 2015). New Zealand reservoir modellers have shown that, if a field is rested, it can recharge over a period of time. While the NZ Battery function cycle would be much shorter than outlined by Bromley, the low load situation could allow the field to commence natural recharge (or at least discharge at a lower rate). In theory, even greater generation would be possible for a given resource, since the benefits of reservoir recharge have not been factored in.

From a consenting perspective, it is assumed that Regional Councils or the Environment Court will continue in their roles and will remain conservative in terms of consents for an initial field development. However, it is also assumed that, when considering the long-term framework of field operations, Councils or the Environment Court will allow averaging of flows over five years. On this basis, the potential for considerable overbuild (compared with conventional base load capacity) may be possible.

The base cases assessed have limited the installed capacity to the expected field conventional baseload capacity.

VALUE ENGINEERING ALTERNATIVES FOR DEPLOYMENT

The base case assumes the use of 4 x 25% generating units. This offers flexibility, in that duty units on each field can be rotated to ensure that no single unit is used more than another and provides the option of bringing on increments of generation on each field. However, an alternative project could include the use of 1 x 25% and 1 x 75% plant. The advantage of this is that some economies of scale could be realised through use of a much larger unit.

Rough assessments indicate that an overall Capex saving of between 6-7% might be achieved through this option, though more spares would be required and there would be less redundancy. This would require the single 25% unit on each field to run continuously over its life, however, this reflects normal operation for a geothermal plant with a high load factor over a long operational life. If there is difficulty in starting the large unit, then all battery function on the field will be lost until the issue is fixed, whereas an issue with one 25% unit will leave two remaining units operating. Discrete increments of battery generation are still available through selection of an appropriately sized field within the battery portfolio, rather than occurring on each field.

5.6.3 GUIDANCE FOR NEXT STEPS

- We recommend reaching out for early engagement discussions with potential iwi and local stakeholders
- Arrange supplier market briefings, and then, where required, set up NDAs, Memorandums of Understanding with key drilling contractors, OEMs for geothermal turbine and balance of plant suppliers
- Initiate detailed geotechnical, geochemical and sub-surface assessments of back of stack sites to identify prime targets and refine the information on their potential resource conditions

- Prepare conceptual designs and develop project process descriptions, preliminary project specifications for the expected plant required for a 400 MW geothermal deployment (with a wide brief that focuses on controlled schedulable operation, with optional consideration of short-term load following operation mode)
- Discussions on the status and future planning of geothermal carbon reinjection trials with geothermal power plant OEMs and operators, as well as findings from existing trials, will further inform this technology, so that it could be successfully incorporated into a NZ Battery geothermal plant by 2030.

5.6.4 PRELIMINARY IMPLEMENTATION SCHEDULE

The following schedule is provided to illustrate a potential implementation pathway to achieving a completed geothermal NZ Battery by 2030.

PRELIMINARY SCHEDULE BASIS

A report prepared for the New Zealand Geothermal Association has informed the base and risk adjusted schedules: Assessment of the Current Costs of Geothermal Power Generation in New Zealand (2007 Basis) published in October 2009. This report was highly consulted across the New Zealand geothermal industry and remains well-referenced internationally. Final implementation activities were initially directly copied from this report, whereas earlier exploration activities and consenting which were not considered in the report were added based on wider experience.

The 2030 delivery date was kept in mind and reasonable opportunities to compress the programme were looked for. Five separate sites have been allowed for with staggered starts to account for differing rates of progress with landowners and other stakeholders at the start. No specific sites are assumed so the staggering is simply a provision rather than being based on any specific perceived difficulties.

The risk adjusted schedule allows additional time for reaching the decision for notice to proceed, and the pre-procurement, procurement and construction stages, resulting an additional 3 years (and a mid-point of 1.5 years).

The programme is necessarily simplified. Initial activities include iwi and stakeholder partnering and activities that feed into the consenting of exploration.

A relatively short exploration consenting period is allowed for as exploration consents are easier to obtain than full development consents. Drilling contracts and civil contracts can be prepared during this period ready for tender on granting of consents.

Twelve months is available for simple roads and pads, the drilling of four exploration wells and the testing of these – a compressed schedule.

Information from this and parallel environmental and social research not shown in the schedule then feeds into development concepts and consents. If necessary additional well testing and modelling can continue through the consent application preparation period.

A full year has been allowed for the development consent process despite a statutory nine months under EPA procedures. This is partly influenced by the Tauhara II Project consent period with an application lodged in mid-February, time spent reviewing completeness, and Minister's decision to fast-track the process made in mid-April, with decision on consents by mid-December. Hence there may be a month or two of float in this.

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The tender period is relatively compressed, and any unnecessary float in the consenting period could be used to extend the tender period to allow more time for negotiation.

The latter part of the programme was based on the report mentioned above, with opportunities to run activities in parallel where ever possible and based on the experience of WSP personnel with other geothermal projects.

A small contingency has been allowed in the consenting period though this could be taken up in contract tender extensions and negotiations.

Contingency is also contained within the staggering of the various sites. The last site is scheduled to commence the exploration then development process almost one year after the initial development.

There is further contingency at the end of the process. The first geothermal battery site will be available as early as February 2029. From that date, completion of sites will be adding capacity to an already operational facility.

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HYDROGEN

6 HYDROGEN

In this section, we consider and assess the potential to manage dry year risk using green hydrogen in the NZ Battery Project context.

6.1 INTRODUCTION TO SOLUTION

Green hydrogen is being pursued globally as a critical enabler to decarbonise hard-to-electrify elements of the energy system. It facilitates the integration of renewably produced energy because hydrogen and its derivatives offer a chemical energy storage medium that can be transported or piped at large-scale to locations required for end uses, including electricity generation, at a future date.

In the NZ Battery context, a hydrogen solution would meet the key *large scale*, *long term*, *renewable* criteria. Green hydrogen production, via large scale, variable off-peak loaded electrolyser plant could utilise what might otherwise be spilled or stranded renewable energy sources e.g. over-capacity hydro reservoirs, or under-utilised wind and solar. It has the potential to support the decarbonisation of New Zealand's energy system, as it may allow more wind and solar (Variable Renewable Energy (VRE)) generation to be built, and also improve plant utilisation by providing additional off-peak power loads and load response benefits. Once produced from water and renewable electricity, the green hydrogen would be converted to ammonia, which is more readily stored, then cracked back to hydrogen to generate electricity when required in dry years. Excess green ammonia could potentially be sold and exported on the international market in non-dry years to add a large-scale demand response energy benefit to the solution. The option for large scale direct fuel CCGTs with ammonia is covered in Section 6.3.9, but it will be 2040 or beyond before this fuel option is technically mature.

The previous Options Analysis task led to green ammonia (a hydrogen derivative) being considered as the most viable hydrogen energy vector for the NZ Battery Project, largely due to its technological readiness and ability to be stored and transported at large scale. This was also based on engineering judgement that it has lower technology maturity risk and complexity than renewable synthetic methane (its main alternative). For further background discussion and commentary refer to the Options Analysis Report.

With green hydrogen production being energy intensive, the electricity demand on the network was a key consideration for sizing the potential hydrogen facility. This study suggests a green hydrogen production plant, with an associated green ammonia production and bulk storage facility, is the most appropriate option.

This report explores and tests the feasibility and risks associated with a stored green ammonia solution and considers the feasibility of:

- Electricity load demand response, via switching off hydrogen production plant in dry years and halting associated green ammonia exports. Also providing load demand response in non-dry years, to support grid security events
- Using stored green ammonia, converting back to hydrogen for dry year 100% green hydrogen–fuelled Combined Cycle Gas Turbine (CCGT) electricity generation
- Enabling excess green ammonia, once domestic users are supplied, to be exported to global customers.

The introduction and confirmation of the inclusion of demand response as a solution for the NZ Battery was determined following the initial Options Analysis Report. While it doesn't take the form of a physical energy storage solution, MBIE modelling data provided to WSP has determined that use as a demand response solution could provide a benefit in a NZ Battery context.

6.2 KEY CONSIDERATIONS

The following sections set out the key considerations that informed the development of a base case for a green ammonia NZ Battery solution.

6.2.1 TECHNOLOGY MATURITY

A complete hydrogen solution, using green ammonia as a storage medium, involves several process steps:

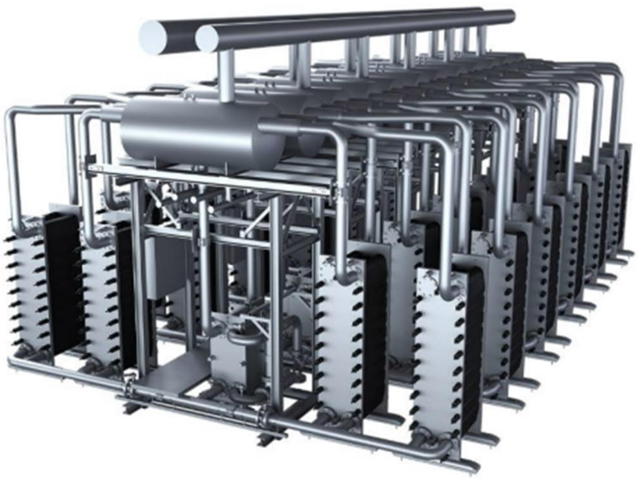
- Green hydrogen gas production plant (electrolyser)
- Hydrogen gas compressor and buffer storage in vessels
- Green ammonia synthesis process plant
- Green ammonia long term storage tanks
- Ammonia cracking plant to convert back to hydrogen gas (generation option only)
- Hydrogen combustion turbine generation plant (generation option only).

The technology involved in this solution has varying levels of maturity. If sanctioned today, New Zealand would be among the early adopters for a green ammonia plant at the scale required for a NZ Battery solution, however, much progress is anticipated before 2027, which is the likely sanction point of a project operational by 2030.

There are numerous gigawatt scale projects under discussion at pre-sanction status (predominantly in Australia, The Middle East and North Africa). The most advanced GW scale project is the Neom Helios project in Saudi Arabia, led by a consortium including Air Products and Saudi utility, ACWA Power. This project will soon start construction of 4 GW of renewables feeding 2 GW of electrolysis for hydrogen export, significantly larger than the base case proposal for NZ Battery. Information on local and international projects is provided in more detail in Appendix D(I).

Despite recent developments in hydrogen-based energy solutions, there remains a steep learning curve for large-scale electrolysis, flexible ammonia synthesis, ammonia cracking and hydrogen power generation. The maturity of the various technologies is, therefore, a key consideration in evaluating this solution. The maturity levels of the various process steps are discussed in the following sections.

HYDROGEN PRODUCTION / ELECTROLYSER



Siemens Energy's Silyzer 300 PEM Electrolyser. Source: Siemens Energy

Proton Exchange Membrane (PEM) and Alkaline electrolysers are the most commonly used and commercially available types of electrolyser. Alkaline is the more mature technology, but PEM offers advantages, in terms of response time and likelihood of future improvements. The technology selected for the project will need to match the variable operational requirements of the NZ Battery solution. This requires an electrolyser that is flexible enough to shut down to accommodate a dry year demand response (over a three-month period), which both technologies can accommodate. As a secondary objective, the electrolyser must operate a shorter-term load following demand response to help fill in daily power peaks and troughs. PEM electrolyser technology is more likely to be suitable for this short-term response, due to its superior ability to ramp up and down compared to alkaline, and better match any anticipated variable off-peak renewable energy inputs ("VRE spillage"). Alkaline technology is, however, currently cheaper and should not be ruled out at this early stage. Alkaline electrolysis also has a stronger track record than PEM, although neither has yet performed at gigawatt scale for any significant duration. A comparison of PEM and Alkaline technologies is provided in Appendix D(VI).

Key performance aspects for electrolysers e.g. long-term stack life, production efficiency, degradation rate and reliability are yet to be confirmed and vendors will likely be hesitant to offer strong warranties until they better understand the performance of their own products. There is, however, a vast amount of both PEM and Alkaline research underway and future cost reductions and technology improvements are anticipated, as manufacturing capability (automation and scale) and materials improve, and proponents learn by doing. This will almost certainly result in cheaper, more efficient electrolysers that could potentially be available by the time this project is ready to purchase.

Currently, electrolyser units are available in modular packages of up to 20 MW and can be procured from overseas Original Equipment Manufacturers (OEMs). An order of 300-400 MW would be considered large, based on current manufacturing capacity, but by 2027 an order of this scale is expected to be within the manufacturing capability of OEMs. Procurement strategies will be required to ensure the required electrolyser plant and key Balance of Plant (BOP) can be secured in time for installation and commissioning by 2030.

COMPRESSED HYDROGEN BUFFER STORAGE

A compressed hydrogen storage solution will be required to act as a buffer between the electrolyser plant and the ammonia synthesis plant. High pressure, compressed hydrogen gas vessels are a mature technology and already exist in New Zealand (e.g. BOC Gas). While technically feasible, compressed hydrogen is an expensive storage method and better alternatives may be available within the project timescale. Storage solutions are currently evolving to meet new hydrogen storage challenges (e.g. a metal hydride "battery" storage solution). Certain parts of the world utilise natural salt caverns for storage. While New Zealand lacks salt caverns, geologically suitable sub-surface bulk storage is currently being explored e.g. depleted wells, however, these may not be sufficiently impermeable. Other geological structures have been suggested in various studies as potential storage options, but none have been found, tested and validated currently. The environmental and safety considerations of the base case storage option are discussed in further detail in Appendix D(I).

Hydrogen storage options. Source: Adobe Stock

AMMONIA SYNTHESIS

Ammonia is a well understood, globally traded commodity. Traditional ammonia plants have evolved to benefit from economies of scale, close process integration and operate 24/7. The new challenge for green ammonia synthesis is linking the synthesis plant with an intermittent green hydrogen feedstock, generated by variable renewable energy. The ammonia synthesis process contains complicated rotating equipment and reaction vessels that do not respond well to variable operating duties. This problem must be overcome if an uninterrupted electrical feed cannot be secured. For this reason, hydrogen gas buffer storage vessels are generally used to provide a more continuous feed supply to the ammonia production plant.

Shutting down the ammonia synthesis plant for long durations during a dry year scenario is not considered an issue but ramping up and down for shorter term load following demand response on a daily or hourly basis will be difficult and presents significant safety risks. The solution to the problem lies with a combination of battery (electric) storage to buffer the electrolysis plant, hydrogen gas storage to buffer the ammonia plant or the improvement of vendor ammonia synthesis designs to better respond to the variable nature of hydrogen feedstock.

Vendor designs for this mode of operation are still immature, but both battery (electric) storage and hydrogen storage options are feasible, albeit expensive. Refer to Appendix D(III) for further details of the challenges and potential mitigations of the variable running of an ammonia synthesis plant.

LIQUID AMMONIA BULK STORAGE

Around the world, liquified ammonia is stored in various sized, full containment refrigerated tanks ranging in capacity from less than 30,000 m^3 to 75,000 m^3 (with bigger tanks proposed).

Four full containment storage tanks, each with approximately 50,000 m^3 capacity, are planned for the base case. The environmental and safety considerations of this storage option are discussed in further detail in Appendix D(I).

LARGE SCALE AMMONIA CRACKING PLANT

To date, ammonia cracking (conversion of liquified ammonia to hydrogen gas) has had little commercial interest, however, an increasing focus on ammonia as a renewable energy storage vector is now driving the ammonia industry (e.g. OEMs such as Thyssenkupp and Haldor Topsoe) to provide solutions. Presently, ammonia cracking is limited to a pilot scale, but we expect these technologies to increase in scale and efficiency over the next few years. Technically, there is nothing stopping this progression. The option for large-scale, direct fuel CCGTs with ammonia is covered in Section 6.3.9, but it will be 2040 or beyond before this fuel option is technically mature.

Governments such as South Korea, Japan and Singapore are extremely interested in the development of this technology, as it is key for them to import renewable energy for use in power generation. There is, however, a risk that commercial development of the scale required for this project could stagnate, if alternatives to ammonia as a mechanism for moving hydrogen emerge, or the push to net-zero diminishes. As it stands today, ammonia is the most common method proposed for the bulk transportation of hydrogen.

COMBINED CYCLE GAS TURBINE (CCGT) POWER PLANT

Natural gas CCGT is a mature technology and is continuously developing. CCGT units, fuelled with 100% hydrogen gas, are more recent developments. OEMs such as GE and Mitsubishi are currently signalling the availability of these 100% hydrogen-capable CCGT units by around 2025. The main turbine component modifications required for a 100% hydrogen-fuelled unit is in the combustion chambers, burner controls and fuel supply systems. The actual turbine components are unmodified.

Industry experience is expected to have advanced significantly by 2027, in time for sanction by the NZ Battery Project.

Direct Ammonia-fuelling Parallel opportunities should also be monitored, such as the development of green ammonia-fuelled turbines which, if matured, would eliminate the need for the ammonia cracking step.

IMPACT ON BASE CASE DEVELOPMENT

Due to the rapidly evolving nature and uncertainty of hydrogen technology globally, the base case intentionally includes a range of potential elements (“building blocks”) that could make up an eventual project solution. The inclusion and sizing of each element is un-optimised at this stage. Of the potential technology elements, running the ammonia synthesis plant in a variable manner, and the ammonia to hydrogen cracking plant steps have the most uncertainty around achieving suitable technical maturity by 2030.

The variable ammonia synthesis plant risk can be mitigated through sizing a larger hydrogen gas buffer storage volume. The base case includes a nominal amount of storage to partially mitigate this risk. More or less may be required, depending on the degree of advancement in variable OEM ammonia synthesis technology.

One approach to mitigate the ammonia cracking plant uncertainty could be to defer the deployment of ammonia-to-hydrogen-fuelled electricity generation to post-2030 in a staged manner e.g. by delivering an initial build with green ammonia export only, which will still provide load demand management benefits, and then build the cracking plant later, linked with the CCGT units to provide 150 MW of renewable thermal generation during a dry year event.

6.2.2 LARGE SCALE STORAGE OF GREEN AMMONIA

Ammonia is a hazardous chemical that is toxic, corrosive and flammable. Long-term storage of large volumes of green ammonia will need careful consideration to ensure that safety and environmental risks are managed to an acceptable level.

While large-scale storage of ammonia is unprecedented in New Zealand, storage technologies are well established and proven internationally. Ammonia is a key input to the production of fertiliser and ammonia made from fossil fuel pathways and has long been a globally traded commodity. Provided safe design and the establishment and compliance with storage, handling, operating and maintenance procedures, anhydrous ammonia storage is generally considered safe. However, great care will be needed to minimise the likelihood of a release scenario, which could have catastrophic consequences to life and the environment e.g. in the event of a fire, heat could rupture tanks, leading to a release of ammonia and a toxic, corrosive and freezing hazard to people nearby. In sufficient concentrations, ammonia can cause permanent damage or death.

Resource Consent Implications

Obtaining a consent for large-scale ammonia storage is a key consideration. While resource consent implications will apply to all the NZ Battery technology options (and are covered separately in this report), the following assessment is provided here because consenting is a prominent key consideration for the hydrogen technology. Under the Resource Management Act (RMA), resource consent is required for a development that breaches a rule in a District or Regional Plan. In considering applications, consenting authorities are required to consider the *actual* and *potential* environmental effects of the development proposed, along with the degree to which matters of national importance (relating to the preservation, protection, and maintenance of the environment), sustainability and kaitiakitanga, and Treaty of Waitangi obligations have been achieved. Applications must be supported by an Assessment of Environmental Effects (AEE), which outlines the baseline environment, actual and potential effects of the development, any mitigation proposed, and the residual environmental effects. The existing (baseline) environment is important when determining potential environmental effects e.g. a previously developed brownfield site will have a different baseline sensitivity than a greenfield, or undeveloped site.

In addition to determining the acceptability of the proposals against policy, the level of environmental effect is also used to determine whether an application should be notified (public or limited notification). If affected parties do not give written approval to the proposals, or the consenting authority decides that the effects of the development are more than minor, the application may be publicly notified. This allows submissions to be made on the application and often results in the decision being subject to a hearing. At this stage of the process, public perception of the development and effective stakeholder engagement are critical to the success of the venture. Generally, the scale and significance of the project determines the likelihood of notification. Therefore, designing development proposals that meet the requirements of policy and minimise adverse environmental effects will navigate the planning system more easily. At this stage of the process, a decision can be made on whether to request that the notified application is directly referred to the Environment Court, bypassing the Council hearing stage.

The RMA is currently subject to reform, which may alter established consenting pathways. A move has been signalled towards a requirement for environmental outcomes to be achieved. These outcomes would seek to maintain or enhance the existing baseline environment and require applications to evidence how the proposed development would contribute to those outcomes.

IMPACT ON BASE CASE DEVELOPMENT

While large in scale, this storage technology at current volumes is proven and deployable. However, both the likelihood and consequence of a release scenario increases in line with increased storage volume. Following investigations into tank type and size options, the base case proposes to store liquified ammonia in four 50,000 m^3 capacity, full containment (double-skinned) tanks with a total storage of approximately 200,000 m^3. This limits the volume of stored ammonia product to less than the largest storage for hazardous refined products in New Zealand currently, at approximately 280,000 m^3 total site storage capacity. This volume of ammonia equates to three months of 150 MW power generation for dry year deployment.

The consequence of a significant ammonia release will be high, but the likelihood of this event occurring is extremely low and will be appropriately mitigated by engineering and procedural safety measures. There is no technical reason why storage volume could not be increased, if required, but social acceptance is considered a greater risk. Community engagement and education will, therefore, be critical.

A risk assessment modelling exercise was carried out, using WSP's specialist Industrial Process Engineering Team in Australia. The aim of this exercise was to consider risk and consequences associated with fire, explosion and toxic release of ammonia and hydrogen to support preliminary site development optioneering. No specific location is implied within this report, however, compliance with relevant health and safety standards for the storage of hazardous substances[8] will be required. This will dictate appropriate separation distances from sensitive receivers e.g. highways, railways, places of public assembly, residential, commercial and industrial buildings, and hospitals.

This work also included Consequence Modelling using DNV Phast Dispersion Modelling Software. Consequence Modelling illustrates the outcomes that may result from hazards on a site and takes into account safety regulations, responses to hazardous incidents and other factors to inform the safe optimisation of plant and process design. A copy of this initial modelling report is provided in Appendix D(I).

6.2.3 HYDROGEN PRODUCTION AS A DEMAND RESPONSE

Due to its large electricity demand, hydrogen electrolysis could act as a form of demand response i.e., producing hydrogen in non-dry years using any available variable, off-peak renewable power and then halting production in dry years to release the load back into the system. Demand response presents a potentially attractive option for hydrogen production given:

- The electrolyser's technical ability to flex

[8] Health and Safety at Work (Hazardous Substances) Regulations 2017, AS/NZS 2022 (2003) and referenced documents BS777.2 for the engineering of secondary containment (skin) for the containment of any inner tank ammonia leakage. Refrigeration systems to comply with AS/NZS 1677.2.

- The energy-intensive nature of the hydrogen production process
- The possibility of a number of large-scale grid-connected developments intending to operate around intermittent renewable generation
- The potential for demand response to provide an economic approach to operation, depending on green ammonia and electricity prices – however noting the uncertainly of these prices.

It is worth noting that several large-scale grid-connected green hydrogen developments in other countries plan to operate in a similar manner.

Sizing of the electrolyser load is a key consideration of a hydrogen solution, where demand response is a key driver. This should be sized to use as much electrical load as is deemed economically viable to supply locally i.e. the amount of additional renewable generation that could reasonably be developed in New Zealand to support an additional load. This must be balanced against the risk of creating too much hydrogen, which would either need to be stored or exported as green ammonia. The consideration of the international export market is explored further in Section 6.2.4.

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By way of context, current New Zealand national grid peak load demand sits at around 6,000 MW and can rise to 7,100 MW. The highest peak demand recorded in New Zealand was 7,100 MW on 9 August 2021 (source: Transpower NZ). The current largest load demand in the country is NZAS Tiwai Point Aluminium Smelter in Southland, who have a contract agreement for a peak base load of 572 MW (roughly 10% of typical peak national demand). The Infrastructure Commission's recently released Rautaki Hanganga o Aotearoa New Zealand Infrastructure Strategy has indicated generation capacity could need to increase by 170% to meet the electrification demands of domestic and industrial end users in the next few decades. With this demand load in mind, WSP has selected a base case green hydrogen/ammonia production plant electrical supply load under 400 MW.

IMPACT ON BASE CASE DEVELOPMENT

For the base case, WSP has suggested a grid-supplied production plant power supply load of 369 MW, operating at 60% load factor. This power supply load is predominately comprised of the planned 350 MW electrolyser plant loading, the planned ammonia synthesis plant power loading and production plant Balance of Plant (BOP) power loads. An upper range of around 700 MW could be possible, but is deemed more of a stretch, when considering the increasing demand associated with the general electrification of industry. Consultation with Transpower and potential developers would be required for the next phase of this development.

In any year, depending on the prevailing hydrology, cloud cover and wind speed, variable renewable generation in New Zealand will change. The green hydrogen production rate can respond accordingly. The aim with the electrolyser load is to flatten out the overall power demand curve, wherever possible, and stimulate higher utilisation of any potentially "stranded" (generation unable to enter the electricity market due to insufficient grid load/demand) renewable generation. To ensure the hydrogen production costs are kept as low as possible, low-cost electricity is used wherever possible.

Commercial Information [redacted] For this base case, WSP has chosen a 60% electrolyser load factor as a reasonable assumption.

6.2.4 INTERNATIONAL MARKET DEVELOPMENT RISK

The sizing of hydrogen and ammonia production facilities, and the economic feasibility of the demand response option, is dependent on the international market for renewable ammonia. We acknowledge there is currently a risk that, by 2030, an appropriately sized market for the sale of green ammonia produced in New Zealand may not exist.

Renewable Ammonia Market Trends

Assuming a robust and dominant certification scheme is in place, there will likely be a spot market for renewable ammonia in the future. The International Renewable Energy Agency (IRENA) has estimated that, by 2050, a 688 Mt/y ammonia market will exist, 82% of which will be produced using renewable electricity. This forecast relies on a range of government policies being in place, and several announced projects reaching a final investment decision and commencing construction.

In terms of new power generation capacity additions, renewable energy generation is currently outpacing fossil-powered generators. This trend is expected to continue, with demand for the long-term storage of renewable energy (e.g. in the form of ammonia) expected to increase accordingly. It is reasonable to assume there will be a significant increase in both ammonia trading and the share of global ammonia that is "renewable". Manufacturers across a range of sectors have already demonstrated innovative uses of ammonia as a fuel source (gas turbines, combustion engines), and countries with ambitious decarbonisation targets have taken steps as potential major off-takers (Germany, South Korea, Singapore, Japan) or producers (Australia, Saudi Arabia and others) of renewable ammonia.

Green hydrogen is now able to compete more closely on price with blue hydrogen (hydrogen produced from a fossil fuel, with Carbon Captured and Stored (CCS)), due to recent upward pressure on international natural gas and coal prices. Ammonia (produced from fossil fuels) is already traded on global markets as a commodity and predictions have been made that "green" or "renewable" ammonia will become a tradeable commodity as early as 2025. WSP believe that, while a market will likely exist in 2030, it may not be in the form of a truly global, tradeable commodity with a spot market for a few years beyond 2030.

Many projects WSP is involved in are seeking to enter into off-take agreements prior to reaching Financial Investment Decision (FID) (or sanction), as the revenue stream must be guaranteed in order to secure project financing in the first place. This suggests that, while there may be a global market, a truly liquid market (like oil or gas) may not be developed until sufficient assets have outlived their initial off-take agreements. This will probably be around 2040, as many large-scale projects have announced they will be online by 2030, and an off-take agreement typically lasts for 10 years, similar to renewable energy Power Purchase Agreements (PPAs).

If an off-taker can be found to regularly accept ammonia produced, the NZ Battery Project could be financed by sales of green ammonia, so long as appropriate buffer storage and contractual flexibility can be incorporated to account for off-take flexibility (stoppage) during dry years.

Green Hydrogen Certification

For international renewable ammonia markets to function effectively, there is a need to differentiate physically identical green products from brown, via an internationally recognised certification scheme(s) tracking and certifying the origins of clean hydrogen products traded. These schemes are currently in their infancy or consultation phases and there is uncertainty around exactly what these will look like in 2030. The EU is probably the most advanced with its CertiHy Scheme. Australia is also developing a Hydrogen GO (Guarantee of Origin) Scheme, drawing on elements of the CertiHy Scheme, which seeks to measure and display key attributes of how and when hydrogen is produced, including its carbon intensity.

For the purposes of this study, it is assumed that ammonia produced by the NZ Battery will be certifiable as “renewable” to whatever standard the international market requires, which is a reasonable assumption, given that precursor hydrogen will be produced using exclusively renewable electricity from the national grid. Similarly, that New Zealand will be able to purchase renewable ammonia to an acceptable standard, if required.

IMPACT ON BASE CASE DEVELOPMENT

The base case provides dry year benefit through a combination of:

a) demand response, where the production facility will be completely shut down to reduce load on the grid and;

b) providing generation capacity, using cracked ammonia (hydrogen) as fuel.

The base case is sized to serve a modest green ammonia export market, as well as replenishing ammonia storage to meet the dry year generation demand. Oversizing the facility for export brings greater potential benefit via demand response because the realised load reduction during a dry year will be greater. The project will also benefit from green ammonia sales and greater economies of scale. The decision to oversize must be balanced against the risk that the green ammonia export market does not develop as quickly as some industry commentators are forecasting.

If there is a reasonable expectation at the time of project sanction (2027) that this market is not developing, then the electrolyser and ammonia plant could be sized downwards to supply ammonia for dry year generation only. This would negate the need for a port facility and allow inland locations to be considered. Alternatively, the generation could potentially be used more regularly for non-dry year peaking duty, to ensure produced ammonia is consumed before storage tanks reach capacity.

6.2.5 OTHER CONSIDERATIONS

LARGE RAW WATER SUPPLY

A 350 MW electrolyser plant will require approximately 2,200,000 m³ of raw water annually but could vary depending on water quality and the cooling solution selected for the facility. This water could be provided from sources near the selected location such as lakes, rivers, bores, potable water supplies, wastewater treatment plants or desalination plants. Water will need processing via an onsite Water Treatment Plant (WTP), prior to the electrolyser unit's dedicated water purification processes. The cleaner the initial water supply, the less water treatment will be required (with associated effluent). Gaining water take consents for this volume of water will require a large amount of preparatory work.

IMPACT ON BASE CASE DEVELOPMENT

Large volume water take consents will be a challenge that will need to be worked through once a specific location is identified. There are many water supply options available, and the location selected for the production facility will determine the specific water supply challenges.

Base case development has not been restricted by the requirement for this volume of raw water.

HYDROGEN GAS STORAGE

For the base case, above-ground hydrogen gas buffer storage vessels would be required, to minimise the impact of the variable off-peak renewable power supply and, therefore, variable hydrogen production and feed supply to the ammonia synthesis plant. Hydrogen storage will assist in keeping the plant operating more continuously on day-to-day cycles. During a dry year scenario, the ammonia production facility would be fully shut down.

The storage of compressed hydrogen in above-ground storage vessels will require careful engineering design to mitigate any safety implications and be based on best practice international codes and standards. Detailed modelling of the selected location will need to be undertaken to quantify the zone radiuses of the blast hazards of storage vessels. High pressure storage vessels (approximately 300 bar pressure) would be required, which are currently relatively expensive. Higher pressure storage is beneficial to enable a higher density of gas to be stored in the storage vessels, but this also increases the site safety risks. There will be a design trade-off between the flexibility they provide and their cost.

IMPACT ON BASE CASE DEVELOPMENT

Hydrogen gas buffer storage is required for the base case, due to the variability of the proposed off-peak renewable power supply to the electrolyser plant. The PEM electrolyser is more suited to variable operations, but an ammonia synthesis plant is generally designed for more steady state operation. So, the hydrogen gas buffer storage allows for some flexibility to enable the ammonia plant to keep running for short durations if the renewable energy input is offline.

Future advancements in ammonia synthesis OEM design may enable more variable operation of ammonia synthesis plants in the near future, which may reduce the need for expensive and higher safety risk buffer storage vessels.

LARGE SCALE HV POWER SUPPLY

The base case would require a total electricity supply capacity of approximately 369 MW from the Transpower national grid. The proposed 369 MW capacity HV grid connection point will require transmission lines and switchyard upgrades to be undertaken by Transpower, before production can commence in 2030. The HV grid supply requirement is outside of WSP's current scope of work, but this constraint has been considered in the development of the base case proposal. This is an assumed viable grid loading volume, with associated grid supply challenges and will require associated grid upgrade works to be undertaken in the near future. Early dialogue with Transpower will be required, once a decision to proceed with any large-scale electricity supply requirement or electricity generation input into the grid is made.

IMPACT ON BASE CASE DEVELOPMENT

Around 400–500 MW of additional power supply and associated transmission capacity will be required to service the selected facility location.

With transmission upgrades and infrastructure developments in the near future, the base case power demand is considered achievable but would need to be investigated further, as this may present other challenges for site selection.

6.3 BASE CASE

6.3.1 BASE CASE DEVELOPMENT

CONSIDERATION OF UNCERTAINTIES

Due to the rapidly developing nature of hydrogen technology globally, the uncertainty around key considerations and risks and the relative uniqueness of the NZ Battery application, the assessment and base case presented for the hydrogen opportunity has aimed to cover a range of potential elements ("building blocks") that might make up an eventual optimal solution. The main hydrogen solution building blocks are:

- Green hydrogen production via electrolysers and non-dry year green ammonia international exports, allowing the ability to interrupt hydrogen production in dry years and provide large-scale demand response energy benefits
- Bulk storage of green ammonia converted to hydrogen, with electricity generated via 100% hydrogen-fuelled gas turbines
- Optional importation of green ammonia to top up storage and continue electricity generation via GTs.

Which of these potential elements could ultimately be taken forward as a fully optimised solution, and the best sizing for each, is unknown at this stage. Our approach has been to acknowledge this uncertainty, identify and incorporate appropriate mitigations, where possible, while recognising that, realistically, some uncertainties will remain, particularly for those aspects that are associated with future prospects for international green hydrogen markets and emerging technology developments.

SIZING OF BUILDING BLOCKS

As discussed in Section 6.2.3 the sizing of our base case solution is centred around what is considered a realistic power demand for 2030. To provide hydrogen as a demand response solution, size needs to be substantial but should consider the significant additional load expected for electrification of industry matched to the dry year shortfall. A hydrogen production facility of 350 MW has been assumed (running at a 60% load factor), which gives a total production plant power demand of 369 MW, when including Balance of Plant (BOP) and ammonia production requirements. This could be the load available for use in a short-term demand response scenario. For longer term (aggregate) demand response scenarios (dry year), this would equate to 229 MW.

The size of ammonia storage facilities has also played a key factor in the sizing of the building blocks of the base case i.e. we have elected to keep these below the largest volume of existing refined product storage tanks used in New Zealand (280,000 m^3) limiting storage to 200,000 m^3. Our base case uses four 50,000 m^3 tanks, which are typical elsewhere in the world and carry less risk than larger volume tanks being proposed by some projects. Adopting this approach is considered to lower consenting risks related to safety, environmental and visual amenity.

The gas turbine plant has been sized to maximise generation from the stored ammonia over a three-month period.

Other elements that have been sized for the base case solution are:

- The ammonia synthesis plant is sized to match the electrolyser plant hydrogen gas output
- Compressed hydrogen gas buffer storage vessels are provided, with enough storage for 12 hours of hydrogen feed to the ammonia synthesis plant, which will enable this plant to run on a continuous basis as often as is possible. This volume of hydrogen gas buffer storage will need future design and optimisation work to determine the final optimal storage ratio, considering both cost and operational performance elements.
- Ammonia cracking units are provided for each CCGT unit, with hydrogen gas buffer storage capacity to provide some fuel pressure stability. This buffer storage is likely to be shared with the buffer storage required to feed hydrogen the ammonia production plants. Generally, these two buffer storage requirements will be out of sync with each other
- Two CCGT units of approximately 75 MW are included in the base case, to ensure increased flexibility and resilience. If only a single 150 MW CCGT unit is provided, there is less operational flexibility (i.e. this removes the ability to keep one 75 MW unit in service while the other 75 MW unit is out of service). Additionally, if the 150 MW unit has reliability issues, the whole 150 MW of generation would be compromised during a critical dry year generation period. As the dry year renewable thermal generation will be so critical to national grid security, it is deemed more appropriate to have two CCGT units, rather than just one larger CCGT unit.

WSP has developed a hydrogen calculation spreadsheet model that allows the user to fully adjust all the major plant parameters and test sensitivities. This model has been shared with MBIE for use as a tool to assist with collaborative development of options for an optimised hydrogen solution.

ALTERNATIVE SIZING APPROACHES

Given the uncertainties around technology maturity and the hydrogen international market, alternative approaches to this base case have been provided in Section 6.3.9.

6.3.2 BASE CASE DESCRIPTION

The hydrogen base case involves the creation of green hydrogen from a 350 MW electrolyser plant, which is supplied using any available off-peak renewable electricity from the national grid (assuming a capacity factor of 60%). The resulting compressed green hydrogen gas (H_2) is either temporarily stored in buffer storage vessels or fed directly into the ammonia synthesis plant, where it will be combined with nitrogen (N_2) extracted from the air, to produce green ammonia (NH_3).

This green ammonia is refrigerated to -33°C to keep it in liquid form and will be stored in this condition in large, full containment tanks up to a volume of 200,000 m^3. The storage tanks will be filled in approximately nine months and once full the green ammonia produced can then be exported at a rate of approximately 22,000 m^3 (a small ocean-going ammonia tanker) per month.

When required for dry years, the stored green ammonia is then cracked back to hydrogen and combusted for power generation through a 100% hydrogen-fuelled CCGT.

There are three main components of the dry year energy benefits of a hydrogen NZ Battery, which would be deployed in the following order:

- Electricity load demand response, via switching off hydrogen production plant in dry years and halting the associated green ammonia production and exports
- Converting (cracking) stored green ammonia back to hydrogen for dry year hydrogen-fuelled Combined Cycle Gas Turbine (CCGT) electricity generation
- Importing green ammonia to top up local storage and use for further CCGT electricity generation in a prolonged dry year.

The diagram below illustrates the base case scenario:

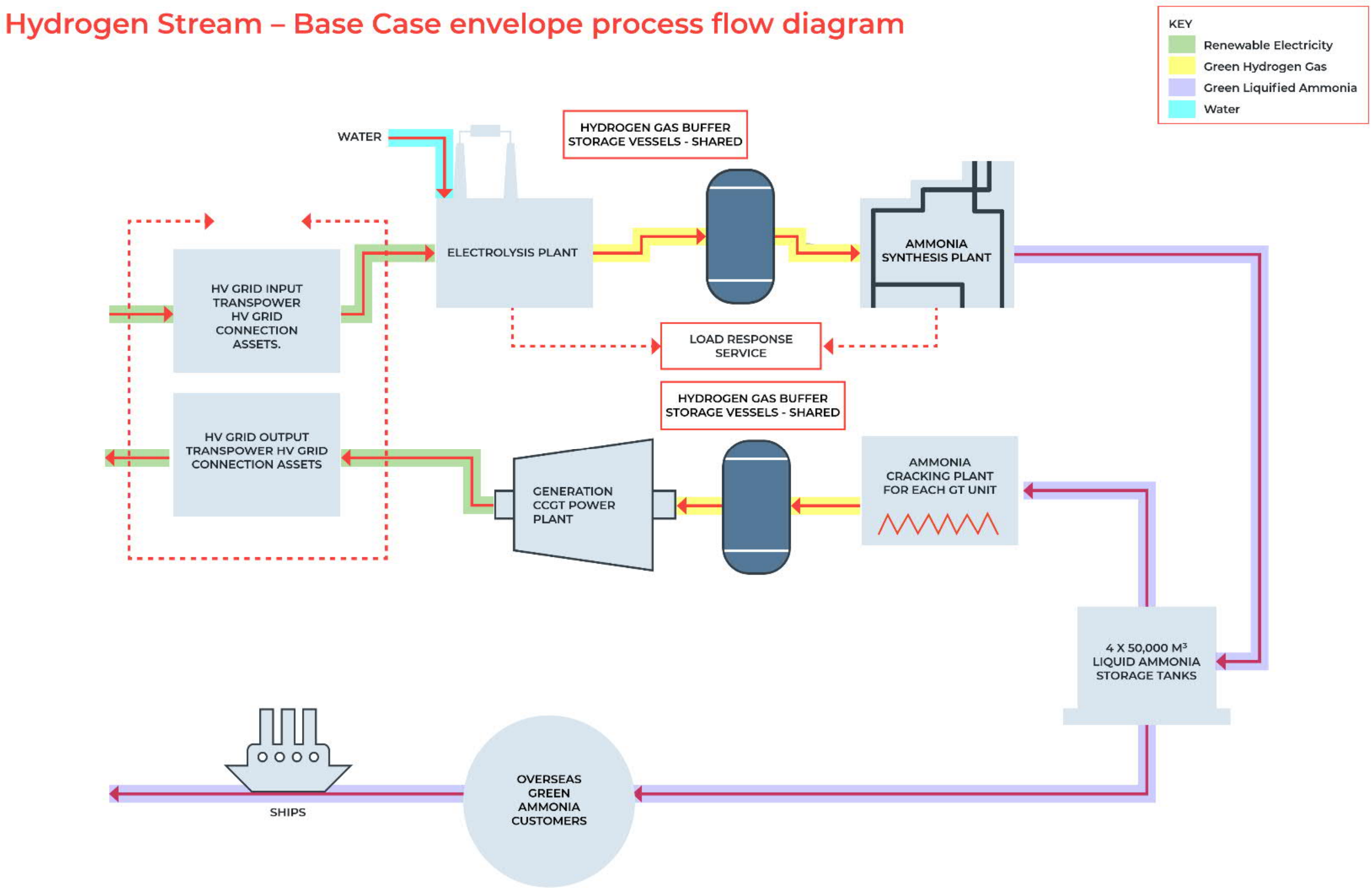

Figure 6-1: WSP Hydrogen Base Case diagram

6.3.3 BASE CASE KEY PARAMETERS

- Electrolyser plant load is 350 MW at 60% load factor, supplied via variable any off-peak renewable electricity from the national grid.
- Hydrogen gas buffer storage vessels, with a capacity of approximately 12 hours of hydrogen gas feed to the ammonia synthesis plant are included.
- The ammonia synthesis plant will have an average daily ammonia production rate of approximately 478 tonnes per day and consume 18 MW of electricity.
- Liquified ammonia storage tank total capacity is 197,529 m^3 (4 x approx. 50,000 m^3 tanks).
- Generation capacity of 150 MW (2 x 75 MW 100% hydrogen fuelled CCGT units), with fuel stocks (ammonia storage) to generate over a three-month dry year period, when required. Generation will feed into the national grid as demand requires.

The table below presents the key parameters described above, together with other relevant figures considered for the base case scenario:

Table 6-1: Base Case Key Plant Parameters Table

Hydrogen Electrolyser Plant	Value	Units
Water supply annually	2,200,000	m^3
Electrolyser nameplate	350	MW
Electrolyser load factor	60	%
Electrolyser aggregate power requirement	210	MW
Hydrogen created annually	30,970	tonnes
Ammonia Synthesis Plant		
Ammonia Synthesis power requirement	19.3	MW
Ammonia Synthesis power requirement including hydrogen production	229	MW
Demand response over 3-month dry year period	0.50	TWh
Ammonia output annually	174,359	tonnes
Liquid ammonia storage	134,517[10]	tonnes
Ammonia Cracking and Generation Plant		
Ammonia input per month	44,839	tonnes
Ammonia cracking power	18	MW
CCGT Generation plant nameplate	150	MW
Net generation over 3-month dry year period	0.29	TWh
Available Electricity Benefit	0.79	TWh

The Available Electricity Benefit of 0.79 TWh is calculated by totalling the following:

- 0.29 TWh is the generation possible from the 150 MW turbine running constantly for three months (2,190 h) *minus* the energy demand of the ammonia cracking process.

  (150 MW – 18 MW) x 2,190 h = 0.29 TWh

- 0.50 TWh is the available energy that is not consumed by the electrolyser and ammonia synthesis process during these same three months – 229 MW for the same hours.

  (350 MW x 60% + 19.3 MW) x 2,190 h = 0.50 TWh

Refer Appendix H calculation spreadsheet for further details.

[10] 134,517 tonnes is equivalent to 197,529 m^3 of ammonia using a density of 0.681 tonnes per m^3

6.3.4 BASE CASE OPERATION

NON-DRY YEAR OPERATING MODE

- The 350 MW hydrogen/ammonia production could operate from 50% to 80% load factor (base case has assumed 60% load factor).
- 200,000 m^3 of ammonia will be stored in tanks to be available for dry years, being filled in approximately 9 months
- Surplus liquified green ammonia will be exported to international markets. This would need to be regular shipments, to ensure production can continue, thereby ensuring the power load demand response opportunity is maximised
- 150 MW CCGT plant is available for operation on a 24-hour recall
- Long term load demand response of up to 229 MW will be available.

DRY YEAR OPERATING MODE

- Dry year event: nominally three to six months
- As soon as a dry year event is forecasted (usually three to four months in advance of the actual dry year event), ammonia production and export would stop, which could allow a demand response of 229 MW, providing 0.5 TWh over three months
- The ammonia cracking plant and the 150 MW CCGT power plant will start up to generate a total of 150 MW electricity from the stored ammonia
- The net electricity output will be 132 MW (when taking off power demand of cracking and generation plant), providing 0.29 TWh over three months
- As a further step, green ammonia could be imported to top up local storage and used for further CCGT electricity generation, beyond the initial three-month period in a dry year.

6.3.5 INFRASTRUCTURE AND PLANT REQUIREMENTS

GREEN HYDROGEN AND AMMONIA PRODUCTION PLANT

Main plant items and considerations:

- Electrolyser units with the 350 MW of input electricity supply proposed are nominally 10 x Siemens Energy - Silyzer 300 - 35 MW PEM units. Each unit consists of 2 x 17.5 MW package of 24 modules (stacks) within a specially designed building structure. This large-scale electrolyser plant would be larger than any other electrolyser plant currently in operation anywhere in the world.
- The modular configuration of electrolyser units provides a large amount of operational flexibility for both maintenance requirements and for times when the variable HV grid renewable electricity supply market has constraints. The PEM electrolyser units could alter load quickly between 0 and 100%, as well as cease operation (within 30 seconds), if required, for grid electricity load demand management purposes, for the System Operator (SO). This is provided by way of example and other vendors offer different, equally valid PEM configurations. Alkaline electrolyser technology should also not be ruled out at this early stage.

- Hydrogen Gas Buffer Storage Vessels (or tube trailers) with a storage capacity to accommodate approximately 10.61 tonnes will need to be sourced. This buffer storage is likely to be a shared facility for ammonia plant supply, CCGT unit hydrogen fuel supplies and local domestic green hydrogen user supplies (when fuel is available). The rationale behind the buffer storage is described in Table 6-2 table below:

Table 6-2: Base case quantities for hydrogen buffer storage

Quantity	Unit	Comment
7.51	t/h	CCGT feed rate
3.54	t/h	Electrolyser output rate
1	h	hours safety CCGT feed
3	h	hours ammonia feed
7.51	t	CCGT buffer
10.61	t	Electrolyser buffer
10.61	t	required storage (largest)

- Ammonia Synthesis plant, including Air Separation Unit (ASU) for nitrogen supply and refrigeration plant. This plant is likely to be a single process train and does not provide much operational flexibility, hence the need to be fed hydrogen via buffer storage vessels so that it can operate for longer continuous periods. Appendix D(III) provides an overview of this component
- Balance of Plant (BOP) support infrastructure, including control equipment, cooling towers, which may be shared with other process plant on site, pipework, cabling, instrument air supply, together with a 110 kV conductor and switchgear from a 220 kV grid connection point:
  - 110 kV switchyard
  - 110 kV to 11 kV step-down transformers, supplying 11 kV feeders to major plant items
  - 11 kV to 415 V step-down transformers, supplying 415 V switchgear/switch room to supply various site services
- Raw water supply and potentially water treatment plant. A range of solutions exist and this will form part of the ultimate site selection methodology.

RENEWABLE THERMAL GENERATION PLANT

Main plant items and considerations:

- Ammonia cracker plant:
  - Specialist liquid ammonia to hydrogen gas conversion plant, with approximately 66,000 tonnes/year of hydrogen gas output

- The ammonia cracker plant will be supplied with liquid green ammonia directly from the liquid ammonia bulk storage tank. One cracking unit will be required for each generation unit to provide 100% hydrogen fuel supply to the GTs
- The cracker plant requires a process heat source, which will need to be an electrical source as the exothermic heat from the ammonia production plant will not be available
- Cooling towers, which may be shared infrastructure with the green hydrogen and ammonia plant
- Ammonia to hydrogen gas conversion (decomposition) using the cracking plant is relatively new technology at scale, however, WSP has expectations that this technology will be available at a unit scalable to provide sufficient hydrogen fuel to a single CCGT unit on full load. A large amount of research is going into the development of this cracking equipment by various high profile Original Equipment Manufacturers (OEMs), which provides us with this confidence

- Compressed hydrogen gas buffer storage and conditioning plant:
  - Hydrogen gas buffer storage vessels may be required to provide buffer storage prior to suppling the GT units. The onsite hydrogen gas buffer storage vessels are likely to be shared plant, which can be utilised for post-electrolyser plant storage, storage prior to feeding CCGT units (in non-dry year periods) and for the supply of future local green hydrogen gas end users. There is a real advantage in fuelling the CCGT generation plant with hydrogen directly from the buffer storage vessels, prior to the ammonia synthesis process, whenever possible. This eliminates these high energy use processes and provides a limited volume of green hydrogen for short-term generation opportunities. This obviously can only occur in periods when the electrolyser plant is operating and will be limited by the volume of hydrogen gas buffer storage vessels available. These vessels are a high Capex item, so careful plant optimisation is required if this operational mode is needed for longer periods of time
  - Hydrogen gas may require cleaning/polishing to bring up to the required 100% hydrogen gas fuel spec for the GT units
- Combined Cycle Gas Turbine (CCGT) generation plant:
  - CCGT generation output capacity of 150 MW over a three month duration (approximately 2,190 generating hours) during a dry year period is planned for, which is limited by the proposed storage. This generation can also be used at other times, if required. Two CCGT units are currently proposed, to provide operational flexibility and redundancy.
  - Currently, OEMs such as GE and Mitsubishi have 100% hydrogen fuelled CCGT models within this size range. Further information on the CCGTs can be found in Appendix D(V)
  - The CCGT could alternatively operate during non-dry year periods via fuel feeds directly from the buffer storage (prior to the ammonia synthesis plant), to provide “green peaker” response.
  - Hydrogen gas compressors may be required to deliver hydrogen gas at a stable pressure, as per the GT fuel supply specifications.
- Export facilities for the loading of excess green liquified ammonia onto ships:

- The ammonia surplus would be available from the bulk storage tanks to load onto export ships via specially built transfer and ship loading infrastructure at an adjacent deep-water port facility

- Facility will be buffer zoned away from other port facilities and will have a restricted entry zone around the hazard facility, both onshore and within the harbour. The exact storage area footprint and hazardous area buffer safety zones are yet to be confirmed

- Deep-water loading berth for specialist refrigerated liquified green ammonia ships (likely to be in the region of 20,000 to 80,000 m^3 capacity)

- Specialist materials handling infrastructure on a specially designed jetty, with pipeline connections to the bulk storage tanks

- Docking times are dependent on the loading rate of the docked vessel, vessel capacity, as well as servicing time at the berth, which can vary between different terminals. The time required to navigate into a port can also vary significantly between locations. For example, if a terminal is accessed via a long access channel/river approach with a strict speed limit, the time in port would be longer than in a location where the berth is directly accessible from the sea. Weather and ocean conditions can also influence how long a vessel spends at a berth

- Typical vessel turnarounds (time in berth only) are outlined in PIANC WG158 indicating that loading equipment at a berth is sized so vessel turnaround occurs in less than 24-36 hours. The unloading equipment on vessels is sized to unload the cargo within 24 hours generally. Currently in-service vessels are capable of loading or unloading at 2-3,000 m^3/h.

6.3.6 GEOGRAPHICAL REQUIREMENTS

The geographical requirements for a Green Hydrogen/Ammonia NZ Battery solution are influenced by the following:

- The avoidance of significant transportation of green ammonia (either via pipework networks or trucking) to minimise associated safety, environmental and land access issues

- The safe exportation of large volumes of liquified green ammonia to international markets, with the optional ability to also import large volumes of hydrogen carrier products in the future

- A location for storage and plant that is either a large rural site (greenfield) or has existing heavy industrial land zoning and is situated away from close receptors (neighbouring businesses) and residential properties

- The requirement for a large capacity HV grid connection point to supply large volumes of renewable energy to the production facility

- Access to a large raw water source.

Based on these considerations, we recommend a port location is preferred, with all plant and storage situated in an "energy hub". Further considerations regarding the energy hub are discussed in Appendix D(IV).

For export purposes, fuel could be loaded from bulk storage tanks onto ships via a specially built transfer and ship loading infrastructure at an adjacent deep water port facility/fuel terminal. The port facility would need to be deep water, to allow ship loading via specialist ammonia transfer equipment, jetties, berths and ship loading infrastructure. The estimated footprint of an energy hub would be 10-20ha.

6.3.7 CO_2 EMISSIONS AND RESOURCE ASSESSMENT

The total embodied carbon output of the base case hydrogen plant has been estimated as approximately 200 kt CO_2-e. It is important to note that this is a calculation based off available plant information at this stage in the project for the key plant items and is not a full lifecycle analysis of carbon. It includes the required plant components, however, construction and transport emissions have been excluded, due to the high-level nature of the assessment.

The hydrogen power option has minimal to no operational emissions, given the highly renewable grid intensity in New Zealand and the assumption that 100% renewable energy will be used to produce hydrogen energy. The electricity requirements amount to approximately 96 TWh over the 35-year life cycle, equating to 2.8 kt CO_2-e with the current Climate Change Commission grid intensity emission factor (embedded emissions of the transmission grid).

The impact on land and biodiversity would mainly arise from land use change. The hydrogen plant in the base case is estimated at approximately 30 ha for a single location energy hub, which could be split over two 8-16 ha sites.

In an extreme scenario, there is potential for ammonia to leak into nearby waterways from the storage tank, or in the event of a shipping issue during the export of ammonia overseas. Given the toxicity of ammonia, this would be disastrous for freshwater quality and ecology. While an extreme risk, this has low probability due to the system being designed with significant risk mitigations.

A total of approximately 1.8 million cubic metres of water will be required over two years to produce the amount of hydrogen needed to run the battery at full capacity in a dry year situation. This high water take presents a potential impact on river-sourced water quantity. Water will be treated in a water treatment plant on site, as it needs to be pure for hydrogen generation, and very little to no water used for energy production will be returned to the water course.

6.3.8 IMPLEMENTATION APPROACH

There are various options and permutations of possible staged approaches that could be deployed to mitigate the relative uncertainty of hydrogen technology maturity, and the uncertain development of an international green hydrogen market for export/import, which include:

- Demand response only, with non-dry year green ammonia export
- Smaller scale hydrogen production, storage and CCGT electricity production, with no ammonia export, could offer less cost and longer storage recharge period (say two years)
- Full scale hydrogen production, storage and CCGT electricity production, with no ammonia export, would have highest cost and a shorter storage recharge period (less than one year)
- Ammonia storage and CCGT only, with ammonia imports.

All of these options would benefit from being designed for implementation in stages. This approach would provide greater future flexibility, avoid “locking in” potentially outdated technologies, and minimise the risk of stranded assets in future depending on uncertain technological developments that could be associated with hydrogen technologies.

An option to mitigate against the technical maturity risk of the various hydrogen, storage, ammonia to hydrogen and GT electricity generation risks, would be to deploy (initially only as a non-dry year option) green hydrogen export/dry year demand response system. With this model, the process focuses only on maximising the non-dry year electrolyser load, exporting the green ammonia as a means to enable a dry year response. Further information on this model is provided in the Section 6.3.9 Alternatives to Base Case.

Another option to mitigate against the risk of a fully functioning international green ammonia market not developing, would be to build only a smaller scale increment of electrolyser and ammonia synthesis plant e.g. initially implementing a lesser quantity of modular build electrolysers. A smaller, 120 MW electrolyser plant would be enough to fill the 200,000 m3 of ammonia storage tanks over two years. This could still be cracked back into hydrogen and fed to the 150 MW of CCGTs to provide the equivalent of 0.29 TWh of electricity over a three-month period during a dry year.

During the next project phase (detailed design), the technical maturity of the required hydrogen plant would need to be further investigated to gain confidence that readiness levels are high enough to proceed with design and construction, particularly related to the Ammonia Cracking plant. In parallel, expressions of interest in international Green Ammonia purchase would need to be explored and off-take agreements negotiated. The outcome of these two key risk items would guide a decision whether to initially proceed with a smaller scaled down solution (i.e. smaller scale hydrogen / ammonia production with no exports or an export only solution sized to suit negotiated agreements) or to proceed with an optimised full scale solution. The plant could be designed to be modular to allow for these considerations. The timeframe to achieve this additional certainty would be tight to meet the aspirational 2030 project completion date and would likely result in a later completion date.

Figure 6-2 provides an example of what a Staged Approach could look like.

Commercial Information

6.3.9 ALTERNATIVES TO BASE CASE

As described in Section 6.3.1, the base case has intentionally been designed to incorporate each of the building blocks, due to the uncertainty of technology maturity and the international green ammonia market. The solution can be adapted to respond to scenarios that remove some of these risk factors.

BASE CASE, PLUS GREEN HYDROGEN GAS ALTERNATIVE USES

During non-dry year event periods, compressed green hydrogen gas can be available for alternative uses. As illustrated in the graphic below, the dotted line shows an alternative green hydrogen gas supply pathway, bypassing the ammonia process, to the CCGT fuel supply buffer storage vessels. This then provides a cheaper green hydrogen gas fuel source, which can be used when renewable thermal generation is required on the electricity market.

Alternatively, hydrogen gas can be supplied to local domestic green hydrogen gas end users.

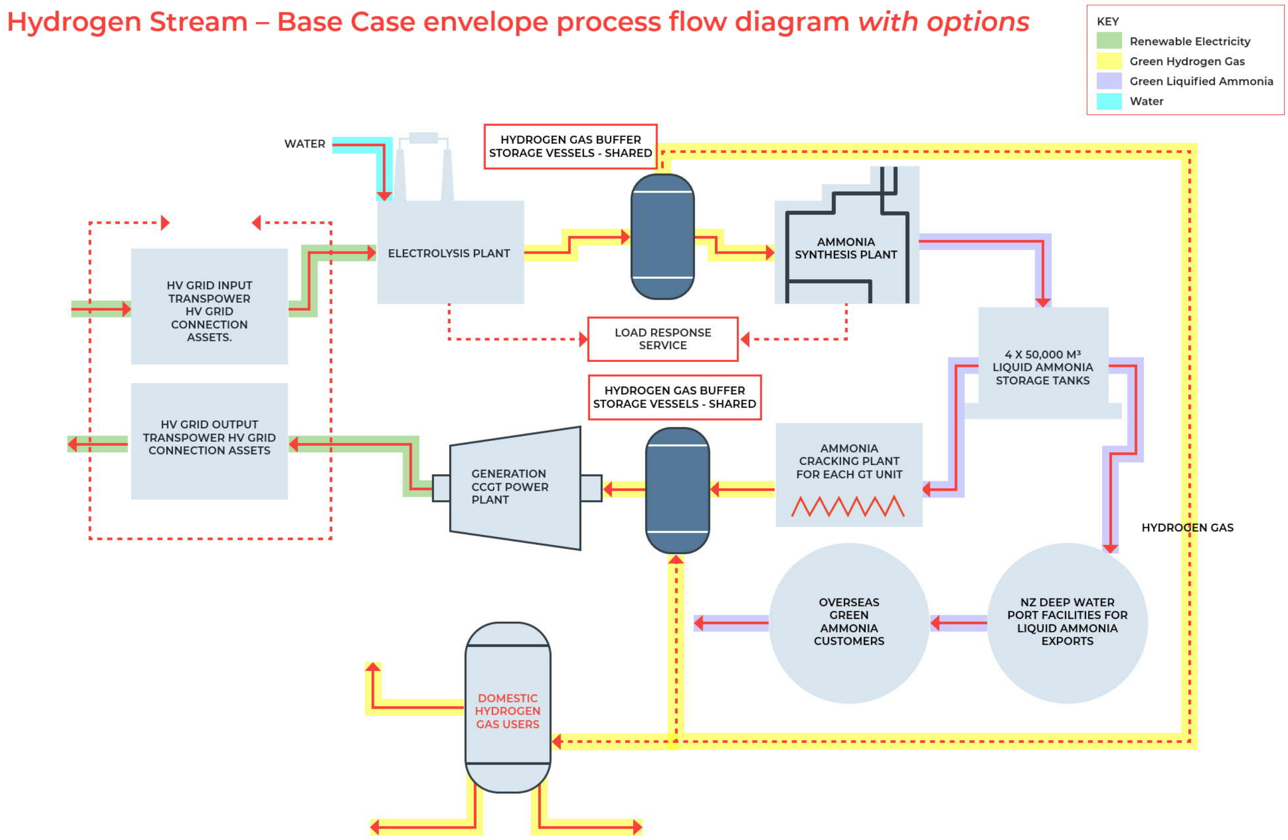

Figure 6-3: Hydrogen alternative options

Dotted line shows an alternative green hydrogen supply pathway (bypassing ammonia process), to CCGT fuel supply or alternative local domestic green hydrogen end users.

USE OF GREEN AMMONIA FOR EXPORT AND DEMAND RESPONSE ONLY

Given the uncertainty in maturity of the ammonia cracking plant, this section provides an indication of what a demand response-only solution would look like, given a scenario where technology does not reach required maturity levels for 2030 implementation.

In this scenario, ammonia is generated via a 700 MW electrolyser (2 x the base case electrolyser nameplate rating) for export as green ammonia. By removing two entire industrial processes (ammonia cracking, CCGT electricity generation), the complexity of this scenario is greatly reduced. The proposed facility also requires no ability to feed electricity into the grid, meaning electrical substation requirements are much more straightforward. This scenario also requires minimal ammonia storage, aside from the volumes anticipated to be installed as part of the port/bunkering facilities required for bulk export. This rate of production amounts to one ship being loaded and departing per month, assuming 30,000 t capacity bulk haulers. The majority of ammonia carriers currently in service have a capacity of between 20 and 30 kt.

Available energy "storage" could be driven exclusively by the aggregate demand response from shutting down production, and hence more dependent on the actual use case of the electrolyser. This scenario is also more exposed to the market risks of the emerging green ammonia market, with its ability to generate revenue and, eventually, a profit directly tied to the sale price that can be achieved for New Zealand's green ammonia.

The following scenario could be possible, when considering a NZ Battery consisting only of demand response from an electrolyser:

Table 6-3: Ammonia for export only

Hydrogen Electrolyser Plant	Value	Units
Water supply annually	8,671,515	m^3
Electrolyser nameplate	700	MW
Electrolyser load factor	60	%
Electrolyser aggregate power requirement	420	MW
Hydrogen created annually	61,939	tonnes
Ammonia Synthesis Plant		
Ammonia Synthesis power requirement	39	MW
Ammonia Synthesis power requirement including hydrogen production	459	MW
Demand response over 3-month dry year period	1.00	TWh
Ammonia output annually	349,000	tonnes
Liquid ammonia storage	0	tonnes
Ammonia Cracking and Generation Plant		
Ammonia input per month	0	tonnes
Ammonia cracking power	0	MW
CCGT Generation plant nameplate	0	MW
Net generation over 3-month dry year period	0.00	TWh
Available Electricity Benefit	1.00	TWh

USE OF GREEN AMMONIA FOR NZ GENERATION PURPOSES ONLY

With the uncertainty surrounding the maturity of the green ammonia market, this section provides an indication of what a green ammonia solution would look like without export i.e. with all green ammonia produced being used only for NZ Battery generation purposes. The following scenario outlines the sizing of facilities to incur no excess ammonia production:

Table 6-4: No/minimal excess ammonia production

Hydrogen Electrolyser Plant	Value	Units
Water supply annually	1,672,364	m^3
Electrolyser nameplate	135	MW
Electrolyser load factor	60	%
Electrolyser aggregate power requirement	81	MW
Hydrogen created annually	11,945	tonnes
Ammonia Synthesis Plant		
Ammonia Synthesis power requirement	7.5	MW
Ammonia Synthesis power requirement including hydrogen production	88.5	MW
Demand response over 3-month dry year period (TWh)	0.19	TWh
Ammonia output annually	67,250	tonnes
Liquid ammonia storage	197,529	tonnes
Ammonia Cracking and Generation Plant		
Ammonia input per month	44,839	tonnes
Ammonia cracking power	18	MW
CCGT Generation plant nameplate	150	MW
Net generation over 3-month dry year period	0.29	TWh
Available Electricity Benefit	**0.48**	**TWh**

Such a scenario produces enough ammonia to fill the storage in two years. The downside of this facility is the relatively minor available demand response and, once the two-year charge time has elapsed, there is no demand response available (as there is nowhere to store the produced ammonia). This scenario would also provide a less resilient NZ Battery in the case of consecutive dry years.

One major upside of this configuration is that it is location agnostic, given there is no requirement for an accessible deep-water port facility, so it can be built inland.

DIRECT USE OF HYDROGEN IN CCGT (NO AMMONIA)

The ability to use green hydrogen gas to directly fuel a CCGT unit is an option to provide a form of thermal back-up generation. WSP does not consider this a viable option, due to the prohibitive cost of hydrogen storage and the variable nature of low-cost, off-peak renewable energy. Currently, the only economically viable large-scale hydrogen storage method globally is salt cavern storage, which is not possible in New Zealand due to the lack of salt caverns. Depleted underground gas reservoir storage may become viable in the future but is currently considered too immature a technology. If hydrogen is to be produced and stored as either a compressed gas or liquid, the cost of storage will vastly exceed the cost of ammonia synthesis/storage/cracking.

NO ELECTROLYSIS (NO AMMONIA SYNTHESIS, IMPORT ONLY)

In a scenario where no local green hydrogen production is desired, all green ammonia will need to be imported and stored at a port location. The storage requirement is decreased, if we assume that ships can dock and unload into the bulk storage tanks while the CCGT is operating, but not by a significant margin, given storage capacity represents at least 15 ship loads (or a minimum of five shipments per month). It is anticipated that this amount of green ammonia will not be available at short notice.

OTHER EMERGING RENEWABLE FUEL TECHNOLOGIES FOR GAS TURBINES

There are several possible future technology alternatives that have potential to be cost-effectively retrofitted to the base case option GT plant from, say, 2040 onwards. This includes direct fuelling of the GT units with ammonia and other forms of hydrogen carriers, whose scale and technical maturity has progressed sufficiently to be reconsidered.

Utilising pure ammonia directly in a CCGT has several challenges, including low flame speed and consequently larger flame size, high auto-ignition temperature, and large volumes of NOx emissions (nitrogen oxides most relevant for air pollution). Many of the major GT OEMs are undertaking R&D work on direct ammonia fuelling of GT, but currently many of them have considerable concerns with this fuel. These encompass the additional hazards it introduces to a generation site and safety concerns if something goes wrong, or there is an ammonia release from the CCGT stack during a failed start-up. This technology is still at a research stage, with the National Institute of Advanced Industrial Science and Technology (AIST) in Japan deploying in 2019 a small-scale 50 kW micro gas turbine using 100% ammonia. Thermal efficiency of up to 22% was achieved and further research into 100% ammonia utilisation is currently being carried out.

6.4 RISKS AND OPPORTUNITIES

A detailed assessment of the risks that are relevant to the selected base case (and alternatives) has been undertaken, as outlined in Section 6.2, and for several key risks, specific analyses were undertaken, which are presented in detail in Appendix D of this Report.

6.4.1 RISK ASSESSMENT SUMMARY

A summary of risks and opportunities for the hydrogen technology is provided in the tables and descriptions below. The tables show the number of extreme, high, moderate, and low opportunities and risks, before and after treatment/mitigation. Refer to the Risk Register in Appendix G for a detailed analysis of the risks, opportunities, assessment, and mitigation.

Hydrogen Opportunities		
	Untreated	Exploited
Extreme Opportunities	0	4
High Opportunities	3	10
Moderate Opportunities	9	0
Low Opportunities	2	0
Total	14	14

TECHNOLOGY OPPORTUNITIES

- Opportunity for emerging technology to improve implementation of the base case. **Exploitation**: Main OEM involvement and collaboration, consider phased implementation, monitor similar projects being implemented overseas. **Exploited Opportunity Rating**: High.
- Opportunity that technology (cracking plant, hydrogen GTs) is able to perform at a higher level than that assumed in the limited scale base case. **Exploitation**: Main OEM involvement and collaboration, consider phased implementation, monitor similar projects being implemented overseas. **Exploited Opportunity Rating**: High.

MARKET AND ECONOMIC OPPORTUNITIES

- Opportunity for other technology solutions that would be turned down in non-dry years to continue supplying power to hydrogen. **Exploitation**: Explore NZ Battery portfolio options at next stage, Options are developing rapidly, so ongoing assessments prior to the final procurement decision may be beneficial. **Exploited Opportunity Rating**: High.
- Opportunity for the hydrogen battery solution to be developed by the market (other commercial organisations). **Exploitation**: Market research and consultation, assessment of cost and benefits of both approaches. **Exploited Opportunity Rating**: High.
- Opportunity for hydrogen battery solution to be expanded to provide electricity market flexibility. **Exploitation**: Assess of market implications and develop a business case. **Exploited Opportunity Rating**: High.

TECHNICAL OPPORTUNITIES

- Opportunity for New Zealand to develop technical expertise and capability in new technologies. **Exploitation**: Use the project to further advance trials/technology, procurement strategy to include learning and development for NZ based people, consider phased implementation. **Exploited Opportunity Rating**: High.
- Potential to prove business case and drive industry uptake of green ammonia. **Exploitation**: Consider phased implementation, consider trials of emerging technology to demonstrate improved efficiency and cost effectiveness. **Exploited Opportunity Rating**: High.

- Opportunity to optimize electrolyser installed during future design stages. **Exploitation**: Option for alternative electrolyser technologies to be used, as base case design is optimised. **Exploited Opportunity Rating**: High.

TE AO MAORI OPPORTUNITIES

- Opportunity to develop partnerships with local iwi. **Exploitation**: Select of sites that could be developed in partnership with Iwi, establishing effective and best practice Iwi engagement strategy, partnership-based decision-making approach. **Exploited Opportunity Rating**: Extreme.
- Economic and social opportunities for Māori groups and communities. **Exploitation**: Project execution strategy to look for opportunities to support development of local businesses and industry opportunities linked to green hydrogen. **Exploited Opportunity Rating**: High.
- Opportunity for local job creation in construction and operation. **Exploitation**: Develop a procurement strategy that values local recruitment and skill development for Māori communities. **Exploited Opportunity Rating**: Extreme.

CULTURAL AND SOCIAL OPPORTUNITIES

- Opportunity for local job creation in construction and operation. **Exploitation**: Develop a procurement strategy that values local recruitment and skill development for local and/or New Zealand based resource. **Exploited Opportunity Rating**: Extreme.

Hydrogen Risks		
	Unmitigated	Mitigated
Extreme threats	33	0
High threats	9	31
Moderate threats	1	11
Low Threat	0	1
Total	43	43

TECHNOLOGY RISKS

- Risk that technology will not be sufficiently mature to achieve base case scale requirements by 2030. **Mitigation**: Further investigate required technology, track technological advancements, adjust scale and timeline as technology improves, Main OEM involvement and collaboration. **Mitigated Risk Rating**: High.
- Risk that technology (cracking plant, hydrogen GTs) is not sufficiently proven/reliable to perform at level assumed in base case. **Mitigation**: Main OEM involvement and collaboration, consider phased implementation, monitor similar projects being implemented overseas. **Mitigated Risk Rating**: High.

- Risk that the plant, once built, becomes obsolete early in its lifetime due to advancing technology. **Mitigation**: Stage development to allow for emerging technology to be implemented. **Mitigated Risk Rating**: High.

MARKET AND ECONOMIC RISKS

- Risk that low availability of process plant equipment prevents the Battery becoming operational at the required scale by 2030. Long lead times are expected on electrolyser, GT, ammonia, tanks, transformers, cracking plant and across all BOP equipment. **Mitigation**: Set adequate timeframes for project development, engage with key suppliers early, develop a procurement strategy, consider phased implementation. **Mitigated Risk Rating**: High.
- Risk of ammonia export not being possible at the expected volume or price. International market is developing and is not yet established. There may be competing exporters of green ammonia closer to demand centres. **Mitigation**: Explore long term green ammonia export contracts, consult with Australian producers, consider deferring the start of hydrogen NZ Battery from 2030 to later. **Mitigated Risk Rating**: High.
- Risk of high costs to connect to the transmission grid. **Mitigation**: Consider risk in site selection, consult with Transpower, provide accurate power loading requirements. **Mitigated Risk Rating**: High.

TECHNICAL RISKS

- Risk that suitable existing port sites are not available to develop the Battery project, leading to challenging consenting processes, delays and increased costs. **Mitigation**: Robust site selection process, early consultation with landowners, secure preferred land packages early. **Mitigated Risk Rating**: High.
- Risk that fuel for the process cannot be supplied to the Battery at the required rate due to constraints in the supply chain. **Mitigation**: Site selection to allow sufficient water supply and allowance for water storage, develop renewable energy with aim to supply battery off peak, early engagement with Transpower and power market stakeholders. **Mitigated Risk Rating**: High.

ENVIRONMENTAL RISKS

- Risk of harm to the environment from construction of new port berths and facilities within waterways or marine environment. **Mitigation**: Site selection process to consider these impacts, use or expand existing ports, robust optioneering and environmental impact assessments, environmentally conscious decision making. **Mitigated Risk Rating**: High.
- Risk of harm to the environment from the construction of new facilities on land. **Mitigation**: Site selection process to consider these risks, design and construction control measures to be implemented to address specific risks, develop Iwi Environmental impact assessments and Management Plans. **Mitigated Risk Rating**: High.
- Potential risk of low water availability for the process. **Mitigation**: Site selection to consider availability of local water, various options for local water supply to be investigated. **Mitigated Risk Rating**: High.

- Risk that commercial renewable power generation does not increase sufficiently to drive the hydrogen battery and it becomes reliant on fossil fuel generation. **Mitigation**: Robust assessment of market impacts, early consultation with power market stakeholders. **Mitigated Risk Rating**: High.
- Risk of harm to the environment due to leak from large scale ammonia storage. **Mitigation**: Detailed design using world class, proven codes, standards and OEM inputs to reduce risk, engineering controls to prevent and/or safely contain leaks. **Mitigated Risk Rating**: High.

TE AO MAORI RISKS

- Risk that the use of water (taonga) in the process negatively impacts Te Ao Māori. **Mitigation**: Establish Iwi engagement strategy, apply Mauri Model cultural monitoring in the assessment of sustainable resource management. **Mitigated Risk Rating**: High.
- Risk of negative construction impacts on Māori communities. **Mitigation**: Establish Iwi engagement strategy, robust site selection process, select sites that are existing industrial sites, partnership-based approach. **Mitigated Risk Rating**: High.
- Risk of harm resulting from lack of partnership with iwi. **Mitigation**: Establish Iwi engagement strategy, select sites in partnership with Iwi, partnership-based approach. **Mitigated Risk Rating**: High.
- Risk of negative operational impacts on Māori communities. **Mitigation**: Establish Iwi engagement strategy, robust site selection process, select sites that are existing industrial sites, partnership-based approach. **Mitigated Risk Rating**: High.

CULTURAL AND SOCIAL RISKS

- Risk of the hydrogen battery operation of being perceived as highly inefficient and cost ineffective for a large investment. **Mitigation**: Base case proposed base load operation to generate power in non-dry years, options to increase benefits through increased generations in peaks etc. to be explored through market implications work, public engagement strategy. **Mitigated Risk Rating**: High.
- Risk of negative construction and operational impacts on local communities. **Mitigation**: Robust site selection process, selection of sites that are existing industrial sites where construction impacts are reduced, establish effective and best practice community engagement strategy. **Mitigated Risk Rating**: High.

HEALTH AND SAFETY RISKS

- Safety risk of large-scale ammonia storage. **Mitigation**: Storage tanks to be designed to standards and codes with specific mitigations, develop response plans to contain, limit volume stored. **Mitigated Risk Rating**: High.
- Risk of ammonia release during transfer from tanks to port/ship. **Mitigation**: Use global design standards, staff training and SOPs will be a key requirement. **Mitigated Risk Rating**: High.
- Risk of blast damage from compromised compressed hydrogen storage/pipework. **Mitigation**: Storage tanks to be designed to code with specific mitigations, storage size to be considered based on risk, consider in site selection. **Mitigated Risk Rating**: High.

CONSENTING RISKS

- Risk of the project not meeting requirements of the Resource Management Act. Specific risks are expanded on within the risk register (refer Appendix G(II)). **Mitigation**: Robust site selection against RMA requirements among other criteria. **Mitigated Risk Rating**: High.

6.5 COSTS

6.5.1 COST ESTIMATE

Feasibility Study Level Cost Estimates (Class 4 estimates to AACE guidelines i.e. -30% / +50%). Refer to Section 2 Approach for details of the Cost Estimate approach.

A more detailed breakdown and derivation is provided in Appendix H and cost estimate spreadsheet that accompanies this report.

Table 6-5: Feasibility study level cost estimates (Class 4 estimates to AACE guidelines, i.e. -30% / +50%).

Estimates excluding revenue			
Hydrogen Total Lifetime Class 4 Cost Estimate (Excluding revenue)			
	Base cost	50th Percentile (approximate)	90th percentile (approximate)
Total Capital Cost (Un-escalated)	Commercial Information		
Total Capital Cost (Escalated)			
Total Capital Cost (Escalated at present value)			
Operational costs (2030-2065) Un-escalated			
Operational costs (2030-2065) Escalated			
Operational costs (2030-2065) Escalated and at Present Value			
Total Cost (un-escalated and not discounted)			
Total Cost (escalated and not discounted)			
Total Cost at PV ($M)			

Estimates including revenue			
Hydrogen Total Lifetime Class 4 Cost Estimate (including revenue)			
	Base cost	50th Percentile (approximate)	90th percentile (approximate)
Total Capital Cost (Unescalated)	Commercial Information [redacted]		
Total Capital Cost (Escalated)			
Total Capital Cost (Escalated at present value)			
Revenue (un-escalated and not discounted)			
Revenue (escalated and not discounted)			
Revenue PV			
Total (un-escalated and not discounted)			
Total (escalated and not discounted)			
Total at NPV ($M)			

6.5.2 KEY ASSUMPTIONS / BASIS OF ESTIMATES

SOURCE OF COST INFORMATION AND CONTINGENCY ASSESSMENT

Past WSP project and gathered OEM cost estimates have been used, with contingency applied based on confidence levels in the source information. In most cases, the WSP hydrogen stream project team has had access to a combination of past global development project cost estimates, past project OEM RFI responses and local project reference cost estimates.

For some equipment e.g. electrolysers, the main OEMs are gearing up to increase their manufacturing capabilities, which will in turn lower unit cost, however, this has stalled lately due to other global pressures.

As the world struggles with high inflationary pressures, pandemic effects, conflict and associated supply chain constraints, large price swings are occurring.

All of the above has influenced the setting of contingency and funding risk to obtain the expected and 90th-percentile estimates.

GENERAL

- All expenditure values are stated in terms of 2022 NZ dollars
- Inflation (escalation) has been applied to all costs after 2023, using a rate of 3%, which reflects the expected long-term average and not the current rate of inflation

- A discount rate has been applied to future costs from 2023, using the New Zealand Treasury rate for Infrastructure (Water and Energy) and Special Purpose (Single-Use) Buildings of 5% (as of August 2022)
- Goods and services tax is excluded.
- Construction timeframe is assumed to be three years.

DEVELOPMENT COSTS

The sum of the items below approximates Commercial Information the estimated physical work costs.

- **Investigation** costs are for the design option development costs, including site optioneering and concept designs, as well as site field investigations
- **Consent** costs are for the preparation of applications for consents, licences and designations. This includes allowance for processing of applications in minimum timeframes
- **Design and Procurement** includes for the development of designs for the purpose of consenting and specimen designs to go to an engineer, procure and construct contract (EPCC) or design and construct. Design costs following the award of an assumed EPC contract are included within the capital cost estimates
- **Property** costs are based on an assumed area requirement of 30 ha and assumed purchase price of Commercial Information per hectare for former industrial port land.

CAPITAL COSTS

- **Land cost and preparation** – Rehabilitation dependent on land being used, which could vary significantly by location
- **Water supply & treatment** – Base estimate assumes potable water intake, contingency to cover scenario of raw water intake
- **Electrolysis Plant** – Higher certainty allowance in base. Electrolyser installation costs are estimated Commercial Information the total capital cost
- **Hydrogen gas buffer storage vessels** – Based on tube trailers. Storage volume and number of tanks could vary
- **Ammonia Synthesis Plant** – Relatively mature technology. Estimated from supplier quotes
- **Ammonia Storage Tanks** – Based on a quote from suppliers for 4 x 40cu.m tanks. Rates adjusted for 4 x 50cu.m tanks in NZD. Tanks, foundations, refrigeration units. Emerging tech. Potentially high variance in seismic design, depending on location
- **Ammonia Cracking Plant** – Lower certainty due to emerging tech and basis of rates
- **Generation CCGT Power Plant** – Based on Commercial Information per MW. Variable market pricing. Hydrogen fuel capability slightly increases current natural gas fuelled units benchmark pricing, which has been taken into consideration
- **Generation BOP** – Based on Commercial Information CCGT generator and electrolyser estimates combined. Higher risk of variance.

- **Port Facilities** – Base cost for new berth only, assuming potential use of existing port. This includes dredging to allow larger ships, jetty/berth facilities, loading arms and storage tanks.
- Contingency assessment reflects the fact that it is not possible to accurately determine the exact infrastructure build and dredging requirements without selecting a location and determining the ship size/frequency of deliveries
- **Civil roading/transport infrastructure** – Site dependent and could be significant variance between brownfield or greenfield site
- **Associated electrical and control - power supply to and from grid** – Site dependent and could be significant variance between brownfield or greenfield site.

OWNER'S COSTS DURING DEVELOPMENT AND CONSTRUCTION PHASES (UPFRONT)

- Calculated Commercial Information physical works costs. This is expected to include owner costs during development phase such as management fees, financing, setting up management company and setting up supply contracts.
- When this item is combined with the Development item, they equate Commercial Information the physical works cost.

OWNER'S COSTS DURING OPERATIONAL PHASE

- An allowance of Commercial Information has been made in the base estimate for the running of management company overseeing operation of the New Zealand Battery.

OPERATIONAL

- **Annual operational cost (non-dry year)** – To allow for water treatment or purchase costs, electricity purchase, staffing. 80% load factor for off-peak. Fixed operations costs are estimated Commercial Information the total capital cost
- **Annual operational cost (dry year)** - To allow for water treatment or purchase costs, electricity purchase, staffing. Three months of dry year operation. Commercial Information restart turbine. 25% reduction in electricity use. Fixed operations costs are estimated Commercial Information the total capital cost.

MAINTENANCE

- **Annual maintenance** – Inspections, statutory inspections and general minor maintenance of plant
- **Maintenance (short interval)** – Major Inspections and minor part replacement
- **Maintenance (medium interval)** – Statutory inspection of major high-pressure assets. PEM electrolyser stack replacement cost, percentage of total installed capital is estimated Commercial Information the total capital cost. Electrolyser stack replacements after Commercial Information operating hours (or approximately Commercial Information depending on running patterns).
- **Maintenance (long interval)** – Replacement of major components. CCGT turbines. Cooling tower motors. Main plant asset lifecycles:
  - Ammonia Synthesis Commercial Information
  - Storage Commercial Information

- Port facilities Commercial Information years
- Transfer infrastructure years
- Ammonia cracking years
- CCGT generation years.

DECOMMISSIONING

- **Decommissioning cost** Commercial Information the capital cost.

REVENUE

Benchmark of renewable ammonia sale price

Sources typically consider the cost of renewable ammonia to be approximately Commercial Information by 2030, and Commercial Information by 2050. For reference, 1 t of ammonia is roughly equivalent to 5.2 MWh. The cost of transporting ammonia by sea has been estimated at anywhere between Commercial Information. This equates to Commercial Information sold in 2030.

These values are in line with those calculated for reference projects undertaken by WSP. Values being used for calculation of levelised cost of ammonia are as follows:

- Electricity price: Commercial Information
- Electrolyser CAPEX: Commercial Information
- Electrolyser efficiency (average over lifetime): Commercial Information
- Ammonia plant CAPEX: Commercial Information per annum NH_3

Global market trend impact

The overall volume of green ammonia produced and sold is negligible on a global scale. For instance, a 300 MW electrolyser and paired ammonia plant will make (assuming 70% overall efficiency) approximately 350,000 t/y of ammonia, when operating at 100% load factor. Global exports/imports of ammonia are currently around 20,000,000 t/y (noting that more again is produced and consumed in-country around the world).

Over half of all currently serving ammonia carriers are between 20-30,000t capacity. We assume that new ships being built to service the market will follow this trend. As such, we anticipate monthly shipments from NZ to be required, allowing a single vessel to service the route between NZ and Australia, much of South-East Asia, and possibly even Japan.

- **Ammonia sale (non-dry year)** – Based on ammonia price Commercial Information tonne at optimistic end of the scale. No ammonia sold during a dry year. Commercial Information due to potential decrease in ammonia sale price. With another - Commercial Information funding risk
- **Power sale (dry year)** – Power sale (dry year) base case is selling approx. 0.28 TWh via GTs, using stored ammonia, over three months = 280,000 MWh x Commercial Information = Commercial Information No ammonia sold in a dry year. Load response revenue could be estimated by assuming the now available renewable electricity is sold at an off-peak rate e.g. 502,000 MWh x Commercial Information

6.5.3 OTHER PROJECT BENCHMARKS

For the hydrogen technology, there are very limited project benchmarks for use in comparing estimates. Hence, the cost estimates utilised several quotes directly from suppliers and those used on other projects WSP are working on globally.

Example project comparisons					
Project Name	Type/ Scale of project	Location	Date Construction Complete	Other Notes	Cost
Unigel Green Hydrogen	60,000 t/y green ammonia	Bahia, Brazil	TBA (construction commenced July 2022) intended to be online end of 2023	The project includes a 20 MW electrolyser in the first phase, increasing to a 60 MW	USD$120m
Yara-Engie Pilbara	800,000 t/y green ammonia	Australia (Pilbara)	n/a	New plant being built in phase 3 (2028)	Confidential
Minbos Green Ammonia	300,000 t/y green ammonia	Angola	2024	Forecasted cost to be below 300USD/t	Confidential
Port Newcastle	800,000 t/y or more green ammonia	Australia	2022	New production plant to be built at port facility – ongoing development design	Confidential
Project Coyote	800,000 t/y or more green ammonia	North America	2021 – 2022	New production plant to be built at inland facility, also port facility – ongoing development design	Confidential
Project Reindeer	800,000 t/y or more green ammonia	Nordics	2021 – 2022	New production plant to be built at port facility – ongoing development design	TBC

6.6 SUMMARY

6.6.1 HYDROGEN NZ BATTERY OPPORTUNITY

As a NZ Battery solution, Green Hydrogen could offer an interesting long-term dry year solution with minimal operational carbon emissions. The solution proposed includes hydrogen and ammonia production with ammonia storage, both for export (to provide demand response) and for local generation. Not all of this solution could technically be classed as a battery, but ultimately provides the same result as a battery with a 0.79 TWh dry year coverage over three months.

While carrying some market development risk, the flexibility to export or import green hydrogen offers the opportunity to increase the dry year response beyond 0.79 TWh, either by increasing the hydrogen production (and hence demand response available) or supplementing local production with imports. These options are limited by the available spilled renewables and the size of generation plant respectively.

A hydrogen solution incorporating export also brings significant opportunities that could benefit New Zealand. It would provide the ability for renewable electricity generation to be expanded beyond what is needed on our shores and export a 100% green energy product to the world. As well as assuring New Zealand’s long-term electricity security, it would provide a new economic value chain and high value, innovative industry knowledge benefits.

The hydrogen opportunity does, however, present risks around the maturity of plant for hydrogen generation and the need for a green ammonia international trading market to develop, enabling the reliable, long-term export of this product. In addition, there are risks associated with the safety of large-scale ammonia storage, requiring a suitable location that adheres required separation distances, and with consenting potentially challenging due to public perception.

Due to its relatively low level of technical and commercial maturity, the risks associated with a hydrogen solution have correspondingly high levels of uncertainty. In this respect, to mitigate against these risks and uncertainties, a hydrogen option could be best considered for staged deployment in smaller scale increments. This could potentially be done in conjunction with other options, deferring the need for a full-scale hydrogen system until both the technology and market have matured.

6.6.2 OTHER INSIGHTS

CCGT FLEXIBILITY IN DRY YEAR

The CCGT unit will initially start up from cold, when required, for a dry year cover. This is assumed to be a planned event, with months of forecasted notice. Once operating, it is expected that the CCGT will operate continuously and not need to be shut down and restarted. Modern CCGT units have some flexibility, offering start-up times between one and four hours (longer when operating from cold).

The CCGT’s HRSG (Heat Recovery Steam Generator) and the hot sections of the GT’s turbine shafts do need time to warm up and expand. But these times are decreasing, and units can be designed to be more flexible, if required.

Some gas turbine vendors have developed new plant designs with a higher degree of flexibility. For instance, GE has developed a gas turbine, steam turbine and an HRSG system that can provide a ramp rate of 50 MW/min, compared to the normal 10–20 MW/min, and achieve full start up in under 30 minutes, compared to 1-4 hours of the old designs. These are natural gas-fuelled GT designs, but this is directly applicable to 100% hydrogen-fuelled GT unit options. The turbine shaft parts and HRSG are the same on a 100% hydrogen-fuelled GT.

For the base case, the two 75 MW CCGT units would run constantly for a period of three months. A cracking plant unit and hydrogen gas buffer storage will be matched with each CCGT unit, to ensure a stable fuel supply. With two CCGT units, more operational flexibility is possible. If one of the CCGT units is shut down, it is likely that it will be “hot stored” (HRSG damper doors shut, to conserve heat in the boiler, GT shafts slowly turning on barring gear). Any unit shut-down is likely to be for a maximum of 24 hours. Increased shut-downs and start-ups will result in more lifecycle maintenance of the units.

AMMONIA SYNTHESIS PLANT FLEXIBILITY

The requirement to operate ammonia plants flexibly and away from steady state is a new requirement and challenge for the ammonia industry. Ammonia synthesis OEMs are working on this challenge, but presently we assume that ammonia plants can ramp relatively slowly at a maximum of 20% per hour and are limited to a turndown of 20-40% of nameplate rated capacity. Noting that, when in a turned down state, the process will be more inefficient due to recycles.

There may be opportunities to optimise these flexibility rates as OEM plant designs mature.

The Haber-Bosch process for ammonia synthesis was designed for constant operations, so starting up and shutting down the plant too frequently (“dynamic operations”) carries significant risks. In particular, damage to the ammonia synthesis catalysts due to thermal cycling and the loss of containment and safety issues due to hydrogen embrittlement, if the system is shut down and pressure is maintained. Limiting the cycling of this plant has long-term asset life benefits, but this can be designed for, with negative effects reduced to a manageable level.

The total green ammonia production plant, including the electrolyser section and the ammonia synthesis section, is limited in process flexibility by the ammonia synthesis section.

The restricting factor is the amount of hydrogen gas buffer storage provided. These buffer storage vessels are expensive and storing large volumes of compressed hydrogen gas comes with additional site risks.

Getting the balance right between appropriate operation of the ammonia synthesis plant and the volume of hydrogen buffer storage is key to the future design and plant optimisation work streams.

6.6.3 GUIDANCE FOR NEXT STEPS

PLANT SELECTION AND OPTIMISING THE HYDROGEN SOLUTION

WSP have developed a hydrogen calculation spreadsheet model that allows the user to fully adjust all of the major plant parameters and test sensitivities, which has been shared with MBIE for use as a tool. We recommend that this tool is used in conjunction with MBIE’s economic modelling and counter-factual scenario planning to test the many possible variations of plant elements and sizing options. The tool can be used together with costs and insights of other factors to develop an optimised solution that best addresses NZ Battery Project objectives. This optimised solution could then form the basis of a concept design.

RISK MANAGEMENT

Key equipment risks related to technology and scale maturity are recommended to be managed by looking to procure equipment from OEMs with proven products and operational performance.

In some cases, such as the ammonia cracker plant, units should be sized to meet the fuel demands of single generation units. This then allows for small scale plant to be utilised.

We recommend undertaking further investigation into all process and plant areas, to gain more awareness of both the technical and scale maturity of the specific base case items of plant.

We also recommend starting targeted communication with key OEMs to obtain improved equipment information and, hopefully, budgetary costs.

6.6.4 PRELIMINARY IMPLEMENTATION SCHEDULE

The following schedule is provided to illustrate a potential implementation pathway to achieving a deployed hydrogen NZ Battery technology solution by 2030.

PRELIMINARY SCHEDULE BASIS

The green hydrogen base case and risk adjusted schedules assume a start date of April 2023.

The risk adjusted schedule allows additional time for reaching the decision for notice to proceed, and the pre-procurement, procurement and construction stages, resulting an additional 4 years (and a mid-point of 2 years).

Key to finalising a schedule is the large amount of conceptual design work that needs to be completed, in order to finalise project deliverables. Subsequent time must be allowed for iwi and other key stakeholders consultation.

Energy Hub – Production, Storage and Port areas :

Before detailed design work can start, the basis of the concept design (especially preliminary site location confirmation), along with initial stakeholder discussions needs to occur.

This will firstly feed into the production/storage/ port facility Consenting processes, then into the 24-month Detailed Design phase.

Once confirmation of the final consent limits are defined, major procurement activities can start, with an early focus on long lead time oversea equipment items.

Site works can start around the same time, with civil and roading works completed first. Then parallel paths are scheduled for the structural, mechanical, electrical and C&I construction activities. Followed then by site commissioning to enable ammonia production and storage to begin its first production period to fill the storage tanks.

Generation plant areas:

Before detailed design work can start on the generation area, the basis of the concept design, along with initial stakeholder discussions needs to occur.

This will then feed into the consenting processes, then into the 24-month generation plant detailed design phase. This will then lead into the procurement and construction phases, with completion targeted for when full fuel supplies are available from the storage tanks.

The site construction duration will depend on the current state of the selected location. If the site requires substantial remediation, due to existing or past use, this will require more time.

A large amount of the site construction will involve civil activities. Most plant items will require a piled concrete foundation to be constructed, however, these can be undertaken in parallel. Once the major civil works are completed and the major plant items are delivered to site, construction of all main process areas and the port facility can continue, with many parallel paths. Most plant items

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are in modular form and will come to site already tested or partially constructed. The physical interconnection work and control system integration can then occur.

Final process plant testing and commissioning will be a critical time towards the end of this schedule. This is a complex facility, and many safety systems will need rigorous proving and approvals. Green hydrogen fuel will be available to fuel the 150 MW CCGT plant from the start of 2030, if required, and green ammonia exports can be scheduled.

6.7 REFERENCE LIST

[6-1] Health and Safety at Work (Hazardous Substances) Regulations 2017, AS/NZS 2022 (2003) and referenced documents BS777.2 for the engineering of secondary containment (skin) for the containment of any inner tank ammonia leakage. Refrigeration systems to comply with AS/NZS 1677.2.

[6-2] Commoditising hydrogen | International trading of green ammonia could begin as soon as 2025: Trafigura, Rachel Parkes, Recharge News, 2022, <https://www.rechargenews.com/energy-transition/commoditising-hydrogen-international-trading-of-green-ammonia-could-begin-as-soon-as-2025-trafigura/2-1-1225219>

[6-3] MarCom WG 158: Masterplans for the Development of Existing Ports, 2014

[6-4] Decarbonising ships, planes and trucks: An analysis of suitable low-carbon fuels for the maritime, aviation and haulage sectors, Nathan Gray, Shane McDonagh, Richard O'Shea, Beatrice Smyth and Jerry Murphy, Advances in Applied Energy Vol. 1, February 2021

[6-5] Pure Ammonia Combustion Micro Gas Turbine System, National Institute of Advanced Industrial Science and Technology, Japan, <https://www.ammoniaenergy.org/wp-content/uploads/2019/08/20191112.1408-NH3FuelConf_Okafor1.pdf>

[6-6] IRENA Innovation Outlook 2022

[6-7] The Cost of CO2-free Ammonia, Bunro Shiozawa, Ammonia Energy Association, 2020, <https://www.ammoniaenergy.org/articles/the-cost-of-co2-free-ammonia/>

[6-8] Global potential of green ammonia based on hybrid PV-wind power plants, Mahdi Fasihi, Robert Weiss, Jouni Savolainen and Christian Breyer, Applied Energy Vol. 294, July 2021

[6-9] Country traded ammonia logistics and storage, present and future, Olver Hatfield, Argus Media, <https://www.ammoniaenergy.org/wp-content/uploads/2021/11/AEA-presentation-Oliver-Hatfield.pdf>

7 SUMMARY

7.1 COST ESTIMATES

The graphs below present the cost estimates, in terms of range from the base estimate to the 90th percentile (P90) estimate for the three technology base cases. The estimates represent the total cost estimate over the 35-year life of the NZ Battery other technology solution. One graph excludes revenue from sale of energy, and one includes it.

The expected estimate (which aligns with a 50th percentile or P50) lies within this range and includes contingency on the base estimate to account for known risks and uncertainties such as the location.

The P90 estimate is obtained by applying funding risk to the expected estimate. This funding risk amount represents unknown risks that could eventuate influencing the outturn cost. The P90 value represents the estimated value that if the project were, theoretically, to be undertaken 100 times, it is estimated to cost less than this value 90 out of 100 times.

Some specific commentary on the estimate ranges is:

BIOMASS

The biomass expected cost estimate and range lie between Hydrogen and Geothermal, which is influenced by:

- A relatively moderate confidence in cost data used to inform the estimates, due to limited track record of implementing this technology, both in New Zealand and internationally
- The relatively low variance in cost from the potential locations for implementing the project and associated infrastructure requirements
- The potential for fluctuating log supply prices
- The relatively moderate level of risk associated with the availability of equipment, environmental impacts and log supply
- Biomass has been sized to provide 1 TWh of additional dry year energy over three months. This can be scaled up to larger increments of TWhs, by replicating similar systems across multiple sites in New Zealand, with associated pro-rated costs per additional TWh

GEOTHERMAL

Geothermal has both the lowest expected cost estimate and the smallest range of costs, which is influenced by:

- A relatively high confidence in cost data used to inform estimates, due to the strong track record of implementing this relatively mature technology, and having local as well as global experience
- The relatively low variance in cost from the potential locations for implementing the project and associated infrastructure requirements

- The relatively moderate level of risk associated with the availability of equipment, environmental impacts and technical implementation of the schedulable operation
- The scale of the geothermal solution is such that is offers 0.6 TWh of dry year additional energy over three months, noting that it can continue to run for longer with minimal additional costs, providing for example another 0.6 TWh over another three months.

HYDROGEN

Hydrogen has both the highest expected estimate value and the largest range in cost estimates from base to P90, which is influenced by:

- A relatively low confidence in cost data used to inform estimates, due to the lack of track record of implementing this technology, both in New Zealand and internationally
- The potential high variance in cost from the potential locations for implementing the project and associated infrastructure requirements
- The relatively high level of risk associated with the technology, consenting, availability of equipment, electricity purchase prices and ammonia sale prices
- The hydrogen base case solution is able to provide 0.79 TWh of additional dry year energy benefit over three months. Of this, the 0.5 TWh associated with system demand response could continue to be provided for longer periods, however, would incur an opportunity cost in the foregone revenue stream of green ammonia exports for that period.

Geothermal cost estimates are the most impacted by the inclusion of revenue, showing the greatest decrease in lifetime costs. Biomass has the next highest impact, followed by Hydrogen.

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7.2 FOCUS INFORMATION

BIOMASS	GEOTHERMAL	HYDROGEN
Long Term storage for dry years achieved by three-year stockpile replenishment	**Long Term** inherently stored energy	**Long Term** storage as green ammonia
Large Scale Base case 1 TWh over three months	**Large Scale** Base case 0.6 TWh over three months	**Large Scale** Base case 0.79 TWh over three months
Renewable	**Renewable**	**Renewable**
Environmental and consenting challenges some GHG neutrality perception risk	**Environmental and consenting challenges** various sites and locations needed	**Environmental, safety and consenting challenges** of large-scale ammonia
Significant biomass supply chain and logistics required but achievable with robust commercial agreements	**Non-conventional** use of subsurface geothermal reservoirs and topside plant	**Utilises 'spilled' renewables** battery function could capture any excess energy
Readily deployable	**Industry capacity to deliver** constrained but achievable	**Market risks** of globally trading green ammonia by 2030
Can grow new industry in NZ	**Can further grow NZ's unique geothermal knowledge**	**Can grow leading edge technology capability in NZ**
Mature technology with some relatively new boiler technology required.	**Mature technology** with some changes to make schedulable Relatively high commercial and technical readiness	**Immature technology** Relatively low commercial and technical readiness

BIOMASS	GEOTHERMAL	HYDROGEN
Relatively **high commercial and technical readiness**	Relatively **high commercial and technical readiness**	Relatively **low commercial and technical readiness**
Good ability to increase scale potential for up to 4 TWh over three months	**Limited ability to increase scale in MW** but can run longer at low cost for more TWh	**Flexibility to increase scale** through additional demand response or hydrogen import
Options for storage medium debarked logs vs torrefied	**Future Optionality** to switch to conventional baseload	**Staged approach** option allows for technology to mature
Some carbon emissions with harvesting and transport	**Minimal carbon emissions** with NCG reinjection	**Minimal carbon emissions**
Could provide daily peaking	**Can provide short-term load following option**	**Can provide short-term load following option**

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APPENDICES