Appendix E Economic Modelling assumptions

1. Scope

This 'Assumptions book' presents the key assumptions used in the NZ Battery project's economic modelling, as at the cover date. It covers four areas:

- An **overview of NZ battery economic modelling**, which provides the context for and purpose of our assumptions, in section 2
- Our **inflow assumptions** for hydro, wind and solar, are critical as these drive the dry year problem, in section 3
- Our baseline **economic modelling assumptions**, covering everything other than inflows and the NZ Battery Options themselves, in four parts:
  - Common modelling assumptions in section 4
  - Demand-side assumptions in section 5
  - Supply-side generation assumption in section 6 (with accompanying long tables of generation stacks in section 14 at the end of this document)
  - Transmission assumptions in section 7
- Our **NZ Battery options** in sections 8 to 133.

This Assumptions Book focuses on what the assumptions are, rather than the rationale for them. That is for brevity and because in many cases the rationale for the assumptions have been well versed within the NZ Battery Project. In some cases however, where assumptions have been introduced or detailed recently, rationales are included.

The tables distinguish with colour between 'raw' assumptions and derived assumptions, e.g.

Table 10: Sample table: Base electricity demand assumptions

		2021	2035	2050	2065
Growth in Base ex NZAS	% p.a.		0.5%	0.8%	0.6%
Base excluding NZAS	TWh	37.3	40.0	45.1	49.3
		White – Raw assumptions		*Blue – Derived assumptions*	

2. Economic modelling approach

The fundamental purpose of the economic modelling is to:

- Explore whether a particular NZ Battery option could work operationally within the electricity system over timeframes of hours to years (with operation at shorter timeframes being considered, where necessary, separately through detailed power systems analysis)
- The economic benefit that an NZ Battery option could provide, relative to a counterfactual without NZ Battery. To do this, we use exactly the same assumptions for the NZ Battery run as for the counterfactual, apart of course from assuming the NZ Battery option itself in the former.
- Understand how an NZ Battery would integrate with the market and supporting work on resilience and power system integration.

To achieve these aims we engaged two mutually supporting and methodologically independent modelling efforts:

- John Culy's energy model
- Stochastic Dual Dimension Programming (SDDP) modelling

2.1 Culy modelling

The Culy model determines the most economic mix of generation in a particular study year, with an optimisation based on plant gross margins. The plant gross margin is the spot market revenue less the SRMC. The revenue is derived from the full simulation model by week and time zone averaged over inflow years. The plant gross margin is calculated for actual new plant and for a notional very small new plant where none is built yet, to determine the capacity of each plant type built. A manual iterative approach is used. This involves adding new capacity of each type (geothermal, wind, solar, batteries and green peakers) until each new plant just covers its fixed operating costs and achieves a normal return on the capital invested. This also adjusts the mix of wind/solar between regions to take advantage of supply diversity and regional marginal loss differentials. A new entry equilibrium is achieved when each type of available new technology in each region is revenue adequate.

2.2 SDDP modelling

The SDDP model is considered by many in the industry (in New Zealand and overseas) as the 'gold standard' approach to economic-based grid modelling of electricity systems with a significant hydro component.

SDDP is the name of the algorithm, but also the name of a specific model developed, maintained, supported and licenced by PSR[49], that uses that algorithm. We are using the PSR SDDP model. PSR partner the SDDP model with a generation expansion model named OptGen. For brevity, we use the term SDDP in this document to cover both the OptGen and SDDP models being used together. Transpower has developed the New Zealand version of the model over decades with PSR (and Tom Halliburton) and achieved widespread industry and Commerce Commission regulatory acceptance of its application for grid investment decisions.

[49] www.psr-inc.com

We have engaged Brian Moore through Jacobs (initially through EY) to conduct the SDDP runs, supported by Tom Halliburton on expert review, and initially supported by Andrew Sykes of Transpower, who kindly provided a starter-set of SDDP databases, including a full transmission grid model.

The SDDP model simulates system operating costs for a given plant mix, with the objective of finding the least cost generation dispatch. Therefore SDDP takes into account only variable costs, including fuel, carbon charges, variable operation and maintenance costs, the cost of deficits and some penalty costs for the violation of operating constraints. An optimal plant mix is determined by the companion model OptGen. The objective of OptGen is to find the lowest total cost of system operation, including both variable costs and fixed costs, including capital charges and fixed operating and maintenance costs. OptGen uses an iterative search process testing various combinations of new plant to determine the optimal development program of new plant over the planning period. OptGen calculates the total fixed costs incurred for each development program, and solves the corresponding SDDP case to determine the total variable cost of that program.

2.3 Synergistic modelling approaches

Our twin modelling approaches have been deliberately chosen as mutually supporting and methodologically independent modelling efforts, each with their own advantages, and capable of providing assurance of each other's results.

Culy's model is much faster to run than SDDP, and so can be used to explore multiple options, for example the benefits of different combinations of storage (TWh) and capacity (MW) sizes of pumped hydro systems.

The SDDP model is much more granular and hence slower to run, so we have to target its use carefully for key scenarios, but it provides greater granularity. Importantly, as water values will be critical to how a future 100% renewable New Zealand electricity system runs, and the SDDP model calculates them using a best-practice and forward looking algorithm, we can use the SDDP model to support the water value assumptions used in Culy's model. This is critical, as the value of stored energy to the future system with mass intermittent generation could be materially different to the value of stored energy today. The SDDP model can also determine transmission constraints and hence where, what and when transmission upgrades may be appropriate (and is used to support Transpower's NZ Battery project power system analysis as well as the economic modelling). The SDDP model represents the operation of hydro plant in a river chain system in detail including the effect of each plant's head pond and water travel times down the river system.

Table 11: Comparison of Culy and SDDP models as used

	Culy	SDDP
Focus	Electricity sector economic model	
Spatial resolution	Islands with regions for wind and solar, and HVDC link	To regional and substation level
Temporal resolution	Weekly with intra-week duration curves, modelled as typical days with hours resolution	Can be varied, down to hourly
Grid model	HVDC only, with losses	Full transmission network including limited security-constrained dispatch. Losses modelled on HVDC but not explicitly on HVAC
Hydro / pumped hydro dispatch	Based on assumed water values	Based on dynamically calculated water values
Prices	Cost-based assuming perfect competition	

2.4 Modelling strengths and limitations

Economic models are powerful tools in gaining insight into complex interactions and inter-relationships, especially those open to quantification and that are beyond past experience. This is very much the case here, given the possibilities of:

- Unprecedented amounts of intermittent generation
- Significant reduction in controllable thermal generation
- Large storage schemes
- Different optimal operating regimes for our hydro resource.

But in considering the outputs of such models, we need to bear in mind some limitations.

Both models assume, in effect:

- Perfect competition
- Perfect foresight by investors on everything except inflows, for which they have perfect foresight on probability distributions
- Risk neutrality by investors.

They assume also that, in the representative year considered, wind, solar and green peaker cost are constant, i.e. that the 1000'th MW costs the same as the first MW. This is a deliberate modelling simplification of a reality where an upwards-sloping cost curve is likely, as wind and solar generation shifts to less favourable sites, or as different technologies or increasingly expensive fuel sources are needed for increasing quantities of green peakers. The results need to be considered in this light.

Both models are cost-based so:

- Output prices are likely to be an underestimate market prices
- Output price forecasts from them are less certain
- Output price volatility forecasts are even less certain.

Both models predict possible futures, but are silent on how we might get there from a regulatory or market design perspective.

As with all models, comparative results are more robust that absolute results. Our economic modelling programme is focused on comparative results, especially the gross incremental economic value of adding an NZ Battery to the system, all other assumptions equal.

3. Inflow assumptions

We use the term 'inflow' for hydro inflows, converted to energy production (GWh) terms assuming the modern hydro fleet, as is conventional. We use the term 'inflow' also to cover wind and solar 'inflows' of wind energy or irradiance, converted to energy production terms, per MW of plant installed.

Using historical inflows at high resolution (daily for hydro, hourly for wind and solar) ensures that we have the best available view of the complexity of hydro, wind and solar interactions.

3.1 Hydro

We used the Hydrological Modelling Dataset from the Electricity Authority, including the 2021 update. This provides generation-adjusted inflows by catchment by day back to 1932.

While the climate probably has changed since the 1930s, and will change further going forward, we used the full range of inflow sequences back to 1932, as there is invaluable time-sequence information in them. For example, there were sequential dry years in the 1970s and we need to ensure that our dry year solution is robust to a repeat of such events.

3.2 Wind

We used wind inflow simulated actuals sourced from the Renewables Ninja website which is based on historical satellite imagery. Forty years of hour data were downloaded for eight regions, back to 1980. Regions used are:

- Northland
- Kaimai
- Hawkes Bay
- Waikato
- Auckland
- Wairarapa
- Canterbury
- Southland

It was found that Renewable Ninja average wind based synthetic data, including its assumed power curves, matches pattern and volatility of actuals[50] quite closely. The Renewable Ninja data were scaled to actuals where possible.

[50] Comparisons were made with available data from Tararua, Te Uku, White Hill, Te Apiti, West Wind, Mahineragi, Te Rere Hau and Waverly (the last estimated to align with observed capacity factors)

3.3 Solar

We used solar inflow simulated actuals sourced from ANSA[51] and based on meteorological records. Forty[52] years of hour data were provided for the following regions, back to 1980. The technology assumptions are described section 6. The regions used are:

Utility solar:

- Far North
- Auckland
- Waikato
- Bay of Plenty
- Hawkes Bay
- Wellington
- Nelson-Tasman
- Christchurch
- Central Otago

Rooftop solar:

- Auckland
- Wellington
- Christchurch

3.4 Aligning hydro, wind and solar sequences

With 40 years of wind and solar inflow data, and 89 years of hydro inflow data, we needed a way of 'back-casting' the wind and solar inflow data to the years 1932 to 1979. We kept wind and solar inflow data aligned together to preserve wind/solar inflow relationships.

We could do that randomly, by for example repeating the same 40-year block, but it would be better to correlate them as much as possible. We tried and tested multiple ways of achieving this, including:

- Annual, quarterly and four-weekly time frames
- Different weightings North Island versus South Island

We measured these approaches against the resultant wind/hydro correlation and, for annual timeframes, the annual inflow deviation. We found that annual matching performed best: it has few discontinuities, avoids seasonality issues and preserves intra year wind/solar correlations.

We therefore mapped each hydro year before 1980 with the closest hydro year 1980 to 2020, and hence with the corresponding wind/solar year.

[51] www.ansa.nz

[52] We actually had 50 years of data, but only used the latest 40 to preserve wind/solar inflow relationships.

3.5 Climate change impacts on inflows

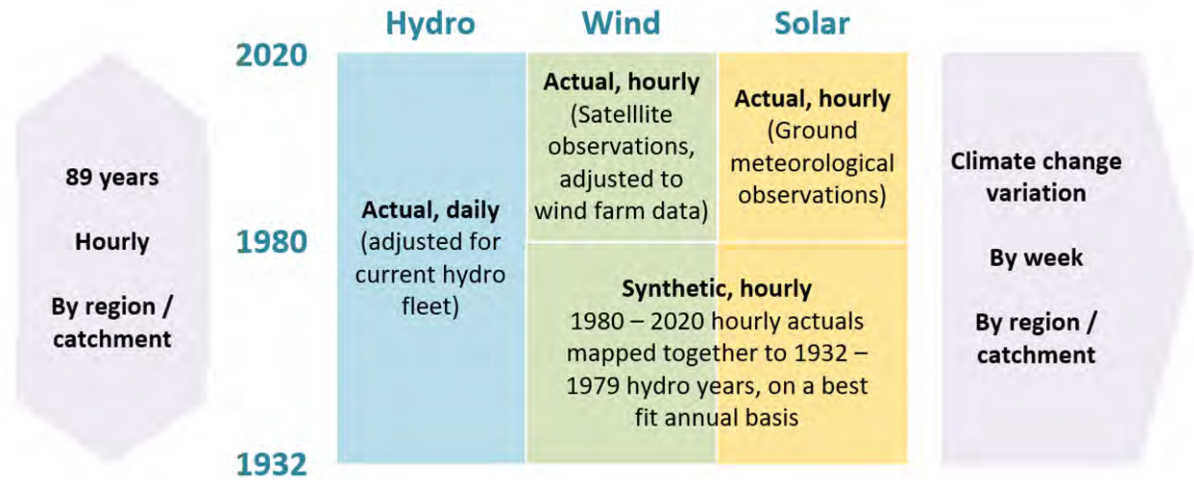
We engaged Dr Jen Purdie of ClimateWorks to estimate the climate change impacts on New Zealand hydro catchment inflows and wind speeds at 2050. She provided estimates by week of year, by catchment for hydro and by region for wind, of expected inflow percentage changes for 2050, noting that:

- There was greater confidence in the direction of the change than its timing
- This confidence of direction is especially strong for South Island hydro, with winter and spring precipitation falling more as rain than as snow, and hence hydro inflows arriving sooner
- There was no evidence of systemic expected changes to irradiance, so we did not adjust solar inflows for climate change effects.

For our baseline modelling, we applied these estimated climate change impacts 50% at 2035, 100% at 2050, and 100% at 2065 (our three modelling horizons: see section 4.1).

3.6 Inflow data summary

Figure 13: Summary of inflow data used



4. Common modelling assumptions

4.1 Reference years

We have focused our effort on studying three representative periods:

Table 12: Economic modelling horizons

Demand and generation	NZ Battery (when modelled)	Reference year
100% renewables achieved Electrification of demand underway	NZ Battery built and in early operation	2035
Electrification about half complete	NZ Battery in 'steady state' operation	2050
Full electrification		2065

As explained below, demand is assumed to grow significantly over time with the electrification of process heat and transport, and is the main driver of the growing need for continuing generation investment over time (given our 100% renewable assumption means that renewable investment to replace existing fossil-fuel generation has already occurred). As there is uncertainty in the rate of uptake of electrification and in the future path of industrial load, and large generation investments have a binary nature, results for these reference years should be considered as 'around then' rather than as precise dates.

4.2 Gross benefits

The model runs with an NZ Battery option do not include the NZ Battery capital or other fixed costs. This is so that the implications of different capital cost structures can be examined ex-post. Comparison of and NZ Battery option to a no-NZ Battery counterfactual thus provides gross benefits rather than net benefits of an NZ Battery.

4.3 Financial assumptions

We use the following financial assumptions for consistency with the NZ Battery indicative business case:

Table 13: Common financial assumptions

Base costing year	*$NZ 2021*	Calendar 2021
Costs	*$NZ 2021*	P50 including contingency
Discount rate	*% p.a.*	6% pre-tax real = 7 % nominal post-tax return on capital

Note that the discount rate used in the models is to reflect the commercial discount rate of market generation investors, and so does not need to be the same as the rate used for the NZ Battery indicative business case. How we use the discount rate to derive marginal, annualise generation costs is described in section 6.2: the post-tax nominal 7% rate gives a capital recovery factor which is very close to that resulting from a using real pre-tax 6% rate in the New Zealand context if the long run inflation is 2% p.a.

In SDDP, a separate discount rate can be used for hydro storage, including of major pumped hydro storage options. Variations to this hydro storage discount rates are considered as a sensitivity.

4.4 Carbon charge assumptions

We have adopted the Climate Change Commission's carbon charge assumptions:

Table 14: Carbon charge assumptions

		2020	2035	2050	2065
Carbon charge	*$ / tCO2e*	$30	$160	$250	$390

Most of our modelling is of a 100% renewables world. Our use of carbon charges is therefore restricted to:

- Geothermal new investments (we assume that existing geothermal plant continue to run baseload, and are replaced with lime plant at end of life, so their emissions net out in our comparative model runs)

- Fossil fuel peakers in our less than 100% renewables sensitivities[53]
- NZ Battery options with any greenhouse gas emissions.

In late 2022, the ETS price exceeded $80 /tCO2e, falling to around $70 in early 2023. We do not use the $30 figure in the table in our modelling, which starts at 2035, and expect to review our future carbon charge assumptions for any future NZ Battery economic modelling work.

5. Demand assumptions

The following sections discuss the context and components of assumed demand.

5.1 NZAS

It is assumed that Tiwai Point aluminium smelter ('NZAS') will be retired before 2035. Its retirement and its timing, and whether it will be replaced on retirement by another large load, is uncertain. Alternative futures are modelled as a sensitivity.

5.2 Base demand

In recent years, average generation has been around 43 TWh per annum (pa) and consumption 40 TWh pa, both including NZAS at about 5 TWh p.a. Generation exceeds consumer load because of transmission and distribution losses. Both the Culy and SDDP models include HVDC losses but assume lossless HVAC grids. We therefore define demand as demand for generation, including HVAC transmission and distribution losses, excluding HVDC losses, and excluding NZAS.

We assume 2021 base demand and annual rates of gross demand growth as follows:

Table 15: Base electricity demand assumptions

		2021	2035	2050	2065
Growth in Base ex NZAS	% p.a.		0.5%	0.8%	0.6%
Base excluding NZAS	TWh	37.3	40.0	45.1	49.3

5.3 Energy efficiency

Demand is assumed net of general efficiency improvements over time, and thus implicitly include the Climate Change Commission's assumptions on energy efficiency improvement. The Climate Change Commission's demonstration pathway includes in its base demand:

- Residential and commercial efficiency improvements of 1% per annum per person. From a 2020 base, this equates to 14% increase by 2035, 26% by 2050 and (in our extended timeframe) 36% by 2045.
- Commercial and public building's heat demand reducing by 2035 by 30% for new builds and 25% for existing.

Efficiency improvements in transport are accounted for explicitly as described in section 5.5 below.

[53] Some NZ Battery technical reports refer to fossil fuel peakers as "black peakers" as a counterpoint to "green" – or renewable energy – peakers.

5.4 Embedded generation

Our demand is gross demand so exclusive of any embedded generation that we explicitly model, including:

- Residential and commercial rooftop solar, covered in section 6.4.2
- Utility wind and solar farms, covered in sections 6.3 and 6.4 (which include embedded and grid-connected plant)
- Small hydro schemes (such as Highbank, Cobb and Waipori) which are accounted separately in our inflow data.

5.5 Transport

Significant transport electrification through the progressive introduction of electric vehicles (EVs) is assumed as:

Table 16: Transport electrification assumptions

			2021	2035	2050	2065
Efficiency	Light	*MWh / vKm*	0.19	0.18	0.16	0.16
	Heavy	*MWh / vKm*	4.24	10.0	12.8	12.8
Usage (EV & ICE)	Light	*billion vKm*	41.7	51.2	53.0	56.2
	Heavy	*billion vKm*	3.16	3.5	3.6	3.9
Proportion of EVs by usage	Light	*% vkm*	1%	45%	95%	99%
	Heavy	*% vkm*	0%	2%	6%	6%
	Off road	*% On Road*	-	5%	15%	20%
Total transport demand	Light	*TWh pa*	0.0	4.1	8.2	8.8
	Heavy	*TWh pa*	0.0	0.8	2.6	3.0
	Off road	*TWh pa*	-	0.3	1.6	2.36
	EV Total	***TWh pa***	**0.1**	**5.2**	**12.4**	**14.2**

Transport demand includes electricity use for travel plus round trip battery charging losses plus average distribution and HVAC transmission losses.

5.6 Process heat

Significant process heat electrification through the progressive electrification of fossil-fuelled industrial processes is assumed as follows, allowing that some industrial decarbonisation will be through biomass or equivalent rather than electrical means:

Table 17: Process heat additional demand assumptions

		2035	2050	2065
Low and mid temperature	*TWh*	2.4	5.2	6.2
High temperature (dairy)	*TWh*	1.8	2.8	2.4
Process heat total	*TWh*	**4.2**	**8.0**	**8.6**

5.7 Summary of gross demand

We thus assume gross base demand as follows, built up from the components described above:

Table 18: Summary of gross electricity demand assumptions

		2021	2035	2050	2065
Base excluding NZAS	TWh pa	37.3	40.0	45.1	49.3
Transport	TWh pa	0.0	5.2	12.4	14.2
Process heat	TWh pa	-	4.2	8.0	8.6
Total gross demand excl. NZAS	TWh pa	**37.3**	**49.4**	**65.5**	**72.0**

5.8 Demand response

Demand response includes the shifting or reduction in load in response to price, as well as shortage, which could for example be manifested, as a last resort, as rolling black-outs. The term 'demand response' tends to mean different things to different people, so we use it as the generic but refer preferentially to three specific forms of response:

- **Load shifting**. This is where 'demand response' is in the form of delayed or shifted consumption of electricity. This includes 'classic' short-term demand response from space or water heating or cooling[54]. It includes also emerging forms of load shifting through the use of batteries, including residential/commercial batteries (possibly as part of a solar system), utility-scale batteries, and smart EV-charging
- **Load curtailment**. This is where load, such as industry, voluntarily reduces consumption in response to high prices. If the prices are efficient at reflecting the marginal costs of supply, this is an efficient and economically desirable outcome. If the prices eliciting the load curtailment are inefficiently high, then such curtailment is inefficient
- **Shortage**. This is where load is forced off because (despite high prices likely to be prevailing), there is not enough voluntary load curtailment to balance limited supply with demand, and demand needs to be physically reduced through for example rolling black-outs. While shortages are undesirable, a power system – especially one like ours subject to the vagaries of weather – 'gold plated' enough that shortage would never occur would not be economic: accepting some small but non-zero risk of shortage can provide an optimum outcome.

Economic models place a dollar value on electricity supply to consumers, which is used to find the economic optimum between increased supply-side investment and reliability and security of supply. It is usually expressed in energy terms, e.g. $/MWh.

Most discussion in the industry on this has been focused on the value of lost load (VoLL), a value enshrined in the Code to guide Transpower's assessment of connection and interconnection investments. Such discussion has been focused on short-term loss of supply measured in minutes or hours. As Castalia have noted, "VoLL would be a relevant concept for setting a security of supply mechanism for capacity-related shortages. It is not a relevant concept when dealing with energy related shortages, since energy related shortages can be

[54] But does not include load shifting from ripple control, which in included in the base demand shapes used.

addressed through conservation campaigns and planned rota-cuts, which impose lower costs per kWh saved."[55,56]

Distribution and average HVAC transmission losses are included, so demand response is measured relative to demand for generation.

Other than these demand responses, demand is assumed inelastic. Thus, if an NZ Battery option reduces average prices, any resultant demand increase and accelerated uptake of electrification is not modelled.

5.8.1 Load shifting

Gross demand implicitly assumes existing levels of load shifting from ripple control, as base demand shapes used are after load control.

EV smart-chargers and embedded batteries are not included in gross demand but are explicitly modelled, based on Transpower's assumptions in Whakamana i Te Mauri Hiko.

5.8.2 Load curtailment

We assume three tranches of increasing load curtailment:

Table 19: Load curtailment assumptions

			2021	2035	2050	2065
Tranche	**Curtail at prices above**	**Percentage**	0.50 GW	0.60 GW	0.80 GW	1.00 GW
1	**$700 /MWh**	40%	0.20 GW	0.24 GW	0.32 GW	0.40 GW
2	**$1,000 /MWh**	30%	0.15 GW	0.18 GW	0.24 GW	0.30 GW
3	**$1,500 /MWh**	30%	0.15 GW	0.18 GW	0.24 GW	0.30 GW

5.8.3 Shortage

We assume three tranches of shortage corresponding to increasingly deep and prolonged shortages.

While we expect our economy and community to become increasingly reliant on electricity as technology and electrification advances, we assume that the economic and social cost per unit for the first responses to shortage – the 'low hanging fruit' – will remain constant over time.

Table 20: Shortage assumptions

Shortage tranche	Covers, for example:	Curtail at prices above	Demand applied to
1	**Conservation campaign**	$800 /MWh	*First 5% GWh use in a shortage*[57]
2	**Shallow rolling outages**	$3,000 /MWh	*5% of demand*
3	**Deep rolling outages**	$10,000 /MWh	*Remainder of demand*

[55] Castalia 2007 Electricity security of supply policy review

[56] EC 2007 Security of Supply Reserve Energy Review Modelling Presentation (web)

[57] This is modelled in Culy but not SDDP modelling, but is rarely used

6. Generation generic assumptions

This section covers our assumptions on new generation and new battery investments, and how our economic models use the assumptions.

6.1 Existing generation

Table 21: Existing generation assumptions

Hydro including contingent storage	Maintained at current levels, with no expansion other than as an NZ Battery option
Wind and solar	Maintained at current levels, until end of life when they are replaced with equivalent or expanded projects.
Geothermal	All existing geothermal plant retained, and Tauhara (currently under construction) assumed commissioned. Variable operating costs subject to the carbon charge. All existing (and new) geothermals are assumed to be "must run", so their operation is unaffected by carbon charges.
Fossil fuel including cogen	All existing fossil fuel generation is retired by 2035 Glenbrook, Kapuni, Kinleith, Mangahewa cogeneration plants remain in service (Te Rapa retired as currently planned)

6.1.1 Contingent storage

Contingent storage is hydro storage that is, by the conditions of its resource consent, only available for electricity generation under certain conditions. Contingent storage is the water at the bottom of the lake, below its normal operating range for electricity generation, so it can only physically be used when the lake is at or below the bottom of its normal operating range.

In most of our modelling runs, we assume that dry years will be managed without resource to contingent storage. For contingent storage scenarios, we assume that the current contingent storage arrangements continue unchanged through our study time horizon.

Table 22: Contingent storage assumptions

Level of risk	Nominal risk	Available contingent storage[58]	Cumulative total	
			Summer	Winter
Normal	<1%	None	0	
Watch	1%+	None	0	
Alert	4%+	67 GWh from Lake Hawea 331 GWh from Lake Pukaki 220 GWh from Lake Tekapo (summer only)	618 GWh	398 GWh
Emergency	10%+	214 GWh from Lake Pukaki	214 GWh	
TOTAL			**832 GWh**	**612 GWh**

[58] Contingent Storage additional information.pdf (transpower.co.nz)

6.2 Marginal new generation investment costs

Because we are focused on modelling specific years, and we are focused on comparison of futures with and without NZ Battery, we use marginal, annualised generation capital and operating costs. While new generation is expected to be built in large ‘chunks’ such as a 200 MW wind farm, we model it as built over time by the MW. This avoids large binary decisions, such as whether that farm was built just before or just after the start of a reference year, from causing artificial swings in cost or benefit when we compare two scenarios for a specific year.

For these reasons, we distil new generation investment costs down to marginal levelised costs of energy (LCOE) in $/MWh and fixed annualised costs in $/kW/year as key parameters. The costs are assumed to continue ‘in perpetuity’ thus covering mid-life upgrades and replacements at end of life.

To develop them we use a real capital recovery factor, calculated for each generation type, which achieves a post tax nominal return of 7%. This gives the real capital recovery required on the assumption of a constant real revenue per annum over an economic life, accounting for timing of cashflows, depreciation, degradation, tax and ongoing or other periodic capital costs such as mid-life upgrades.

6.3 Wind generation investment

6.3.1 Onshore wind

We base our wind generation building-block costs on generic systems:

Table 23: Onshore wind costs by farm size

			Size of farm				
			20MW	50MW	100MW	150MW	200MW
	Capacity available	*MW*	Unrestricted				
CAPEX	Turbines	*$ / kWac*	1240	1230	1240	1250	1220
	EPC other	*$ / kWac*	1800	860	570	480	420
	CAPEX other	*$ / kWac*	210	190	180	180	170
	Contingency	*$ / kWac*	5%	5%	5%	5%	5%
	Total (less transmission)	*$ / kWac*	3400	2400	2100	2000	1900
OPEX	Total	*$/kW/year*	51	50	48	46	44
Proportion in generation stack		*%*	1%	2%	26%	28%	43%

We then assume learning curves for some components, reducing real costs over time. Other components are assumed constant cost in real terms.

Table 24: Onshore wind CAPEX learning curves

	Cost multiplier				% p.a.		
	2021	2035	2050	2065	2035	2050	2065
Turbines and EPC other	100%	87%	78%	76%	-1.0%	-0.7%	-0.2%

We then combine from the previous tables:

- Total CAPEX less transmission, 2022, by farm size
- Weighted by the proportion in generation stack, by farm size, and
- Adjusted by the learning curve per CAPEX component.

To give us the marginal $/kWac and LCOE as below. VOM for wind is low, so we can model it explicitly or include it in FOM, so both options are tabulated:

Table 25: Onshore wind marginal costs

Capital cost excluding transmission		2021	2035	2050	2065
FOM (VOM not modelled)	*$/kW/yr*	46	46	46	46
FOM (VOM modelled)	*$/kW/yr*	42	42	42	42
VOM (if modelled)	*$/MWh*	1.2	1.2	1.2	1.2
Base $/kWac	*$/kWac*	1820	1580	1420	1380
Fixed annualised costs	*$/kW/yr*	190	170	160	150
New entry costs = LCOE	*$/MWh*	54	48	45	44

To this we add transmission costs by region, constant in real terms, calculated as the average costs per kW per region from the wind generation stack (see section 14.2):

Table 26: Onshore wind transmission costs

Region	Cost
	$/kWac
Northland	410
Auckland	410
Waikato	340
Bay Of Plenty	100
Central North Island	290
Taranaki	210
Hawke's Bay	580
Wellington	270
Nelson-Marlborough	330
Canterbury	390
South Canterbury	320
Otago-Southland	280
Weighted average	**320**

Combining the fixed annualised costs and new entry costs without transmission, with these regional transmission costs gives the wind fixed annualised costs and new entry costs by region by reference year.

Note that the following table of fixed annualised costs is presented for the case of VOM not modelled. See the accompanying spreadsheet for the case of VOM modelled, and (as with many tables in this Assumption Book) for more decimal places if required.

Table 27: Onshore wind fixed annualised costs (VOM not modelled)

Region	Onshore wind fixed annualised costs *$/kW/yr*			
	2021	2035	2050	2065
Northland	230	210	190	190
Auckland	230	210	190	190
Waikato	220	200	190	190
Bay Of Plenty	200	180	170	170
Central North Island	220	200	180	180
Taranaki	210	190	180	180
Hawke's Bay	240	220	210	210
Wellington	220	200	180	180
Nelson-Marlborough	220	200	190	180
Canterbury	220	210	190	190
South Canterbury	220	200	190	180
Otago-Southland	220	200	180	180
Weighted average	**220**	**200**	**190**	**180**

Table 28: Onshore new entry costs

Region	Onshore wind new entry costs = LCOE *$/MWh*			
	2021	2035	2050	2065
Northland	63	58	54	53
Auckland	63	58	54	53
Waikato	61	56	52	52
Bay Of Plenty	56	51	47	46
Central North Island	60	55	51	50
Taranaki	59	53	50	49
Hawke's Bay	67	62	58	57
Wellington	60	54	51	50
Nelson-Marlborough	61	56	52	51
Canterbury	63	57	54	53
South Canterbury	61	56	52	51
Otago-Southland	60	55	51	50
Weighted average	**61**	**56**	**52**	**51**

6.3.2 Offshore wind

Investment in offshore wind in New Zealand is possible within the horizon considered. Roaring 40s identify three most likely areas, off the:

- West coast of Auckland, with some 4 GW of potential
- Waikato west coast, with some 2 GW of potential
- South Taranaki coast, with some 2 GW of potential (and the highest wind speed).

As Roaring 40s describe it:

> *The South Taranaki coast option is a large area with an extremely good wind resource (average wind speed 9.6 m/s) and a water depth of less than 50 m. The Auckland and Waikato coast options aren't as attractive from a wind resource perspective (average wind speed 8.3m/s) and are in deeper water (60 m to 150 m deep) but have the advantage of being closer to the large load centre of the Auckland Region.*

Offshore wind is currently significantly more expensive than onshore wind, but its costs are declining more rapidly. Here are the Climate Change Commission's assumptions:

Table 29: CCC wind cost assumptions

	Capacity factor	Capital	FOM	VOM	Cost reduction rate	Capital	
						2035 average	*2050 average*
	%	$ / kW	$ / kW / yr	$ / MWh	% p.a.	$ / kW	$ / kW
Onshore wind	40 %	$ 2100	$ 24	$10	0.53 to 0.80	**1,900**	**1,720**
Offshore wind	44 %	$ 5200	$ 140	$ 0	2.33 to 3.50	**3,349**	**2,175**

There is uncertainty in when and how much offshore wind investment there will be in New Zealand. However, as Roaring 40s conclude, and given that some potential investors are expressing interest[59] we cannot rule out offshore wind by 2035 either. Work is underway within MBIE to develop a regulatory regime for licensing offshore renewables to be in place by the end of 2024.

Our modelling, of onshore wind only, indicates that significant onshore wind investment is likely in the Auckland, Waikato and Taranaki regions (along with wind elsewhere across New Zealand). The modelling takes into account the regional wind resource, the advantages of diversity between regions,proximity to transmission, and losses and capacity of the HVDC link. Wind tends to be stronger offshore than onshore, but with similar shapes to their distributions over time.

Thus, the results of our modelling of onshore wind can be interpreted, through post-processing of modelling results, as including onshore and offshore possibilities in those three regions.

Further, the critical generation investments for the comparative economic analyses are those that depend on the NZ Battery scenario – no NZ Battery, and different NZ Batteries. We try to capture the nuances of the NZ electricity market's response to the supply/demand/storage

[59] For example, the NZ Super Fund and Copenhagen Infrastructure Partners are considering investment in a large scale offshore wind to South Taranaki (web).

balances under each of these scenarios, and assume that onshore wind developments will be more reflective of these differences than would major, binary offshore wind developments.

6.4 Solar generation investment

6.4.1 Utility scale solar generic

To obtain an expected cost per kW we base our building-block costs on generic systems:

- Single-axis tracking, also referred to as azimuth tracking
- Inverter loading ratio 1.3 (i.e. 30% overbuild relative to inverter capacity, with clipping)
- Photovoltaic performance degradation of 0.6% p.a. (on the dc side of the inverter)
- Capacity factor of 22% (as a lifetime average, equivalent to 24% in year one)
- 25 year life.

Table 30: Utility solar costs by farm size, less transmission

			Size of farm				
			20MW	50MW	100MW	150MW	200MW
	Capacity available	MW	Unrestricted				
CAPEX	EPC Modules	$ / kWac	750	670	620	590	570
	EPC Inverters and trackers	$ / kWac	450	430	410	400	400
	EPC Labour	$ / kWac	500	435	390	365	350
	EPC Materials	$ / kWac	500	435	390	365	350
	Other	$ / kWac	50	40	40	40	30
	Contingency	$ / kWac	9.7%	8.9%	7.6%	6.3%	5.0%
	Total (less transmission)	$ / kWac	2,468	2,189	1,991	1,871	1,785
OPEX	FOM	$/kW/year	36	33	31	30	29
Proportion in generation stack			-	2%	20%	10%	69%

We then assume learning curves for modules, inverters, trackers and labour components as below.

Table 31: Utility solar learning curves

	Cost multiplier				% p.a.		
	2021	2035	2050	2065	2035	2050	2065
Modules	100%	**52%**	**26%**	**18%**	-4.6%	-4.6%	-2.3%

We then combine from the previous tables:

- Total CAPEX less transmission by farm size
- Weighted by the proportion in generation stack, by farm size, and
- Adjusted by the learning curve per CAPEX component.

To give us the marginal costs as follows:

Table 32: Utility solar marginal costs

Capital costs exclude transmission		2021	2035	2050	2065
FOM	*$/kW/yr*	0	0	0	0
VOM	*$/kW/yr*	29	29	29	29
Base $/kWac	*$/kWac*	1800	1200	780	670
Fixed annualised costs	*$/kW/yr*	190	130	96	87
New entry costs = LCOE	*$/MWh*	88	61	45	41

To this we add transmission costs by region, constant in real terms, calculated as the average costs per kW per region from the solar generation stack (see section 14.3):

Table 33: Utility solar transmission costs

Region	Cost
	$/kWac
Northland	250
Auckland	220
Waikato	250
Bay Of Plenty	190
Central North Island	270
Taranaki	380
Hawke's Bay	190
Wellington	290
Nelson-Marlborough	270
Canterbury	350
South Canterbury	190
Otago-Southland	280
Weighted average	**260**

Combining the fixed annualised costs and new entry costs without transmission, with these regional transmission costs gives:

Table 34: Utility solar fixed annualised costs

Region	Utility solar fixed annualised costs *$/kW/yr*			
	2021	2035	2050	2065
Northland	207	149	117	108
Auckland	204	146	114	105
Waikato	207	148	117	107
Bay Of Plenty	202	144	112	103
Central North Island	209	150	119	110
Taranaki	218	160	128	119
Hawke's Bay	202	143	112	102
Wellington	210	152	120	111
Nelson-Marlborough	209	150	119	110
Canterbury	215	157	125	116
South Canterbury	202	144	112	103
Otago-Southland	209	151	119	110
Weighted average	**208**	**149**	**118**	**108**

Table 35: Utility solar LCOE

Region	Utility new entry costs = LCOE *$/MWh*			
	2021	2035	2050	2065
Northland	99	71	56	51
Auckland	97	69	54	50
Waikato	98	71	55	51
Bay Of Plenty	96	68	53	49
Central North Island	99	72	56	52
Taranaki	104	76	61	56
Hawke's Bay	96	68	53	49
Wellington	100	72	57	53
Nelson-Marlborough	99	72	56	52
Canterbury	102	75	60	55
South Canterbury	96	68	53	49
Otago-Southland	100	72	57	52
Weighted average	**99**	**71**	**56**	**52**

6.4.2 Rooftop solar

Rooftop solar is modelled at a fixed build rate, so investment in rooftop solar is not a variable optimised alongside wind, utility solar and other generation. This is to reflect that rooftop solar investment drivers are multi-faceted, not just based on wholesale price. Rooftop solar:

- Is accounted for after demand, so it is treated as another form of generation to meet gross demand for generation
- Is implicitly grossed-up to include the quantity of distribution and HVAC transmission losses saved
- Implicitly also accounts for the average level of module efficiency degradation.

Table 36: Rooftop solar assumptions

		2021	2035	2050	2065
Residential	*%*	2%	8%	14%	20%
Commercial		-	5%	7%	10%
Residential installations	*Number of installations (millions)*	0.04	0.16	0.31	0.47
Commercial Installations		-	0.02	0.03	0.04
Residential	*kW per installation*	3.8	4	4	4
Commercial		7	7	7	7
Residential	*TWh*	0.2	0.8	1.5	2.3
Commercial		-	0.1	0.2	0.3
Rooftop		**0.2**	**0.9**	**1.7**	**2.6**

This is similar to the Climate Change Commission's assumption of 10% of household have 3.5 kW solar rooftop installations by 2040.

Rooftop solar is assumed to be in one of the three load centres Auckland. Wellington and Christchurch for which we have full solar inflow sequences (see section 3.3).

We model rooftop solar uptake as exogenous, i.e. not in response to market prices. Hence, the model results can be interpreted for higher or lower rooftop solar uptake – as a first approximation – by considering lower or higher demand, i.e. modelled results for 2050 could be interrupted as say for late 2040s or early 2050s.

6.5 Geothermal generation investment

It is assumed that Tauhara, currently under construction, is commissioned at 250 MW.

We assume new market geothermal investment options in three tranches (after Lawless 2020):

- Low-emissions, with 230 MW available and 60 Kg C / MWh gross emissions
- Medium-emissions, with 450 MW available and 115 Kg C / MWh gross emissions
- High-emissions, with 100 MW available and 150 Kg C / MWh gross emissions.

A significant uncertainty in future geothermal investment is the rate of geothermal carbon re-injection, as:

- Most carbon is already captured, but currently vented to the atmosphere. These gases could instead be re reinjected into the subsurface field. There is some geothermal carbon reinjection in Iceland, the USA and Turkey, and trials are underway here in New Zealand.
- To truly sequester the reinjected carbon, it needs to mineralise, which can happen in basaltic rock such as exists in Iceland. However, the rock type in our geothermal zone is not well suited to mineralisation because it does not contain all the desired minerals found in basalt.
- Absent mineralisation, there is a significant risk that reinjected carbon migrates through the reservoir and leads to an increasing concentration of carbon coming up through production wells, as has been observed in Turkey. It may take years before this effect is observed (or demonstrated not to occur) in our trials.
- Alternatively, it may be that continual reinjection keeps the carbon sub-surface indefinitely, even if it does not mineralise.
- However, the re-injection of carbon can dissolve rock, increasing the permeability of the reservoir around the injection well and beyond, with the possibility of over time creating a CO_2 fountain with local as well as atmospheric impact.
- It is thus an unknown how successful geothermal carbon reinjection will be in New Zealand over our long-term outlook horizon, and successes are likely to be field-specific
- We therefore will run sensitivities around an assumed success rate of 50% for low, medium and high emissions fields.

For modelling purposes, we include the successful 100% injection, zero emission fields with low emissions fields, as they all get built in all scenarios, and different emissions rates can then be post-processed to reflect different assumptions.

This leads to the following capacities of market geothermal availability:

Table 37: Geothermal resource assumptions

		Emissions	Geothermal resource
		Kg C / MWh	*MW*
Emissions tranche	**Zero net**	0	400
	Low	60	120
	Medium	115	230
	High	150	50
TOTAL			**800**

Another significant uncertainty is geothermal capacity factor. Geothermal plant are typically run continually as baseload plant. In recent years our geothermal fleet has been running in the high 80s percentage capacity factors[60]. Lawless (2020), looking forward, suggests

[60] New Zealand Geothermal Association 2020 Annual NZGA Geothermal Review (web), confirmed by MBIE analysis.

capacity factors in the range of 90% to 95% will be achievable. We have assumed a figure in the low 90s of 91%.

Table 38: Geothermal generic generation assumptions

				2020	2035	2050	2065
		CAPEX	*$ / kW*	$5500 / kW			
		FOM	*$ / kW pa*	$ 189 / kW pa			
		VOM excluding carbon charge	*$ / MWh*	$ 0 / MWh			
		Capacity factor	*%*	91%			
Emissions tranche	Low	Emissions	*Kg C / MWh*	Up to 60			
		VOM	*$ / MWh*	$ 2	$ 10	$ 15	$ 23
		LCOE	*$ / MWh*	$ 81	$ 88	$ 94	$ 102
	Medium	Emissions	*Kg C / MWh*	115			
		VOM	*$ / MWh*	$ 3	$ 18	$ 29	$ 45
		LCOE	*$ / MWh*	$ 82	$ 97	$ 108	$ 124
	High	Emissions	*Kg C / MWh*	150			
		VOM	*$ / MWh*	$ 5	$ 24	$ 38	$ 59
		LCOE	*$ / MWh*	$ 83	$ 103	$ 116	$ 137

6.6 Peakers

Peakers are fast-start turbines that can run for an hour or two, or days or weeks or longer. Peakers are modelled in all scenarios, as our modelling of a future world without peakers does not produce a credible solution.

Peakers are assumed to be ‘green’ peakers in our 100% renewable scenarios, which are the focus of our analysis.

We also model fossil fuel peakers as a sensitivity.

Some modelled peaker operation for multi-day events could represent also other technologies operating at similar price levels, such as load curtailment (additional to that covered in section 4.8.2) or storage devices capable of multi-day generation such as flow batteries.

6.6.1 Green peakers

A green peaker is a low capital cost, high operating cost generation plant, running on a zero-carbon fuel. With their high operating costs, green peakers would be expected to operate at low capacity factors only to cover periods of low intermittent renewables and/or very dry periods.

CAPEX costs are expected to be similar to fossil-fuel powered peakers:

Table 39: Green peaker CAPEX assumptions

CAPEX	*$ / kW*	**$1,000**

Lifetime	*Years*	25
Capital recovery factor	*%*	7.8%
Capex recovery	*$ / kW pa*	$78
Fuel holding costs	*$ / kW pa*	$14
FOM	*$ / kW pa*	$10
Fixed costs annualised	*$ / kW pa*	$100

Operating costs are primarily driven by the cost of fuel, which is problematic to estimate across our extended time horizon, and given the variety of possible fuel types, including ethanol, biodiesel, biogas, green hydrogen and green ammonia. We assume $45 / GJ but consider this to be at the cheaper end of a range of possible but unknown prices (and so will perform sensitivity analyses around higher prices):

Table 40: Green peaker OPEX assumptions

Cost of bio fuel	*$ / GJ*	$ 45
Generation efficiency	*%*	34%
Fuel cost of generation	*$ / MWh*	$ 480
O & M	*$ / MWh*	$ 8
VOM	*$ / MWh*	$ 480

Modelled green peaker operation could represent also other technologies operating at similar price levels, such as load curtailment or storage devices capable of multi-day generation such as flow batteries.

We expect to review our green peaker operating costs assumptions to support any further and future economic modelling work.

6.6.2 Fossil fuel peakers

In most scenarios we do not consider fossil fuel peakers in 2035 and beyond. However, in any scenarios that we run with fossil fuel peakers, the following are the assumptions we use.

We assume that coal use for electricity generation ceases before 2035, and that oil use is minimal by comparison with natural gas. This is a conservative assumption, as it is not guaranteed that the market would – with no incentives other than carbon prices – close off coal as an option. So, assuming a gas-only rather than gas and coal future is a strong assumption.

However, given this strong assumption, our issue is the availability and cost of natural gas for electricity generation in New Zealand. The main driver for continued investment in our gas supply chain and infrastructure is likely to be the petrochemical industry and other demand, rather than electricity generation. Our assumption on this is that existing gas peakers and gas storage at Ahuroa are retained, but only used as a last resort backup, and that additional capacity of gas peakers are allowed as required to maintain a secure system (in economic terms) as demand increases.

Because our models use marginal generation costs, we need to distil our assumptions into an annualised fixed cost and a VOM, as below:

Table 41: Fossil fuel peaker CAPEX assumptions

CAPEX	*$ / kW*	$ 1000
Lifetime	*Years*	25
Capital recovery factor	*%*	7.8%
CAPEX recovery	*$ / kW pa*	$ 78
FOM	*$ / kW pa*	$ 10
Fixed costs annualised	*$ / kW pa*	$ 88

For gas costs we assume that gas storage at Ahuroa is maintained at around 11-17 PJ with additional investment to enable greater daily extraction rates (flex) as required, with fixed costs comprising:

- Working capital costs for Ahuroa gas storage as $ 7 million per annum
- Upgrading Ahuroa extraction rate ($ 0.4 billion CAPEX), annualised as $ 41 million per annum
- Option fees to provide gas supply flexibility not met from Ahuroa of $ 15 million per annum.

This suggests the availability of gas for peaking at some $ 13.5 / GJ inclusive of flex.

It is possible that the upstream gas industry ceases to be able to maintain the required upstream investment, in which case imported liquid natural gas (LNG) would set a backstop price. A Gas Industry Company paper[61] provides some insight on future LNG prices, as being not much different than the $ 13.5 / GJ assumed for domestic gas above.

Table 42: Fossil fuel peaker OPEX assumptions excluding carbon

Cost of gas	*$ / GJ*	$ 13.5
Generation efficiency	*%*	34%
Fuel cost of generation	*$ / MWh*	$ 140
O & M	*$ / MWh*	$ 8
VOM excluding carbon	*$ / MWh*	$ 150

Table 43: Fossil fuel peaker OPEX assumptions including carbon

		2021	**2035**	**2050**	**2065**
Carbon content of gas	*kg CO_2 / GJ*	54			
Carbon content	*t CO_2 / MWh*	0.53			
Carbon prices	*$ / t CO_2*	$ 30	$ 160	$ 250	$ 390
Carbon cost	*$ / MWh*	$ 17	$ 92	$ 140	$ 220
VOM	*$ / MWh*	$ 170	$ 240	$ 290	$ 370

61 Gas Industry Company 2021 Gas Market Settings Investigation Consultation Paper (web), section 5.9.

6.7 Grid-scale batteries

We assume that grid-scale batteries (Li-ion or equivalent) will be available in 5-hour and 12-hour sizes:

Table 44: Grid-scale batteries generic opportunities assumptions

			2021	2035	2050	2065
CAPEX	5-hour battery	*$ / kWac*	$2000	$1084	$864	$689
	12-hour battery	*$ / kWac*	$3900	$2114	$1685	$1343
	Decline rate	*% p.a.*		-4.0% p.a.	-1.5% p.a.	-1.5% p.a.
Round trip efficiency		*%*	85%			
Cell replacement rate		*% pa*	1% of total capex			
FOM		*$ / kW pa*	$10 / kW pa			
VOM		*$ / MWh*	Nil			

Transmission costs of grid-scale battery connection are assumed low, as grid-scale batteries are likely to be connected at strong points of the grid, and included in CAPEX.

6.8 Instantaneous reserves

Instantaneous reserves are held such that generation can be ramped up, or load ramped down, within seconds to maintain system frequency should a generation or transmission asset fail. Generation kept as reserve cannot be used for dispatch. Batteries have reserve capability (as do some NZ battery options, including pumped hydro).

Instantaneous reserves are an important feature of the New Zealand market. In particular, HVDC transfer can be limited by instantaneous reserve requirements to cover for HVDC failure.

Our assumption for our horizon of 2035+ is that instantaneous reserve requirements will not cause cost differences between with and without NZ Battery scenarios, because:

- Our modelling predicts very significant amounts of Li-ion batteries with a high capability to provide instantaneous reserves
- North Island reserve requirements for the HVDC contingent event will be significantly less once the 1400MW upgrade is completed
- For southwards flow, Lake Onslow in pumping can in effect provide its own reserve cover through setting its turbines to trip.

7. Transmission generic assumptions

This section covers generic transmission assumptions. In addition there are specific transmission assumptions for NZ Battery options, detailed in their section.

We assume that the grid upgrades proposed by Transpower in their January 2022 Net Zero Grid Pathways (NZGP) go ahead, and are commissioned prior to 2035.

Table 45: Transmission generic generation assumptions

HVDC	HVDC 4th Cable	1400 MW north, 950 MW south
Central North Island upgrades	Brownhill-Whakamaru	We assume 45% series compensation on both Brownhill Whakamaru circuits, 2025
	Brownhill-Pakuranga	Brownhill to Pakuranga cable is operated unconstrained from 2025 (once series compensation in place)
	Tokaanu-Whakamaru 1&2	Duplexed with Goat at 120°C, 2027
	Bunnythorpe-Tokaanu 1&2	Duplexed with Goat at 120°C, 2027
	Huntly-Stratford-1	Circuit protection upgrade to increase effective capacity, giving this circuit the same capacity as the Stratford-Taumarunui-Te Kowhai-Huntly circuit which is strung on the same double circuit towers, from 2029
	Special protection scheme	Tokaanu intertrip scheme disabled (modelled in SDDP by removing TKU bus split)
	Tactical thermal uprate	Ongarue circuit breaker #92 split
Wairakei Ring	Te Mihi-Wairakei-1	Thermal upgrade to 100°C, 2027
	Te Mihi-Whakamaru-1	Thermal upgrade to 100°C, 2027
	Whakamaru-Wairakei-1	Thermal upgrade to 100°C, 2027
	Ohakuri-Wairakei-1	Duplexed Goat at 120°C, 2027
	Atiamuri-Ohakuri-1	Duplexed Goat at 120°C, 2030
	Atiamuri-Whakamaru-1	Duplexed Goat at 120°C, 2027
	Edgecumbe interconnector	62.5 MVA (winter/summer/shoulder)
	Special protection scheme	Edgecumbe-Kawerau-3 and Kawerau-Ohakuri-1 overload protection scheme
Bombay to Otahuhu	Committed projects	New 220 kV bus at Bombay between Huntly and Drury connected into Drury-HLT-1 and Huntly-TAT-2 Remove Arapuni-Bombay and Bombay-Hamilton 110 kV circuits
Additional system splits	Splits on 110 kV system to resolve overloads	Ongarue-Rangitoto-1 Mangamaire-Masterton-1 Edgecumbe-Kawerau 1 and 2 Glenavy-Studholme-2

8. NZ Battery Lake Onslow pumped hydro option

The Lake Onslow pumped hydro scheme is under active investigation: the following assumptions reflect the current state of Lake Onslow design work (MOL = maximum operating level).

Table 46: Lake Onslow main options

	Upper storage	Installed capacity	Upper reservoir	Lower reservoir			
			MOL	Storage	Location	MOL	Pumped?
	TWh	*MW*	*masl*	*Mm³*		*masl*	
Small	3	500	743	0	Negotiations	62	No
Medium	5	1000	765	5		87	Yes
Large	7.5	1250	785	10		86.6	Yes

The assumptions below are based on the 'Medium' option.

Negotiations

8.2 Upper reservoir

Table 47: Lake Onslow (medium option) upper reservoir dimensions

Elevation	Reservoir Storage	Active storage	Area
masl	*Mm^3*	*Mm^3*	*Km^2*
695	246	-	24
705	529	283	32
715	882	637	39
725	1,307	1,062	46
735	1,804	1,558	53
745	2,365	2,120	59
755	2,986	2,740	65
765	3,664	3,418	71

Table 48: Lake Onslow (medium option) upper reservoir evaporation

	Evaporation
	mm/month
January	120
February	96
March	67
April	39
May	20
June	8
July	8
August	21
September	41
October	71
November	96
December	113

There is assumed to be no significant seepage loss, and no net inflows as current flows on the Teviot River will need to be maintained.

Groundwater seepage from the Lake Onslow basin for lake levels from 685m to 765m are expected to vary from <0.1m3/s to 0.75m3/s respectively.

8.3 Pumping and generating performance

The medium option for Lake Onslow has four 250 MW turbines. Turbines are assumed to:

- Be reversible with fully variable loading such that there is a full range of available dispatches between zero and maximum generation and maximum pump.
- Have a very fast ramp rate relative to the highest hourly resolution used in our economic modelling. Their potential contribution to ancillary services is not modelled (other than as discussed in section 6.8).

The following Lake Onslow pumping and generation assumptions are for when all four 250 MW turbines are in operation, in two modes:

- **Sustained operation**, when the lower reservoir is and its lower pumps are in active use as required to maintain pumping volumes over times, so the production coefficients include the main turbines and lower pumps.
- **Arbitrage operation**, in which the lower reservoir is operating in closed loop i.e. no interaction with the river or use of the lower pumps, so the production coefficients include the main turbines only. This is a mode of operation that could be used for daily cycling.

So, the **production coefficients** for the turbines in the tables below capture lower pump efficiency when used in sustained operation. The production coefficients include headlosses in both directions due to long waterways. The ratio of pumping and generating production coefficients give the round-trip efficiency, excluding evaporation effects.

Table 49: Lake Onslow (medium option) turbine performance in sustained operation

Elevation		*masl*	695	705	715	725	735	745	755	765
Pumping	Power consumption	*MW*	1124	1115	1105	1095	1084	1075	1066	1056
	Total pumping flow	*cumecs*	156	153	150	147	144	141	138	135
	Production coeff.	*MW/ cumec*	7.20	7.29	7.37	7.45	7.53	7.62	7.72	7.82
Generating	Maximum output	*MW*	1000	1000	1000	1000	1000	1000	1000	1000
	Total turbine flow	*cumecs*	206	201	196	191	186	183	179	176
	Production coeff.	*MW/ cumec*	4.85	4.98	5.10	5.24	5.38	5.46	5.59	5.68
Round-trip efficiency		*%*	67.4%	68.3%	69.3%	70.3%	71.4%	71.7%	72.3%	72.6%

Table 50: Lake Onslow (medium option) turbine performance in arbitrage operation

Elevation		*masl*	**695**	**705**	**715**	**725**	**735**	**745**	**755**	**765**
Pumping	**Power consumption**	*MW*	1092	1084	1074	1065	1055	1047	1038	1029
	Total pumping flow	*cumecs*	156	153	150	147	144	141	138	135
	Production coeff.	*MW/cumec*	6.99	7.08	7.16	7.24	7.33	7.43	7.52	7.62
Generating	**Maximum output**	*MW*	1000	1000	1000	1000	1000	1000	1000	1000
	Total turbine flow	*cumecs*	206	201	196	191	186	183	179	176
	Production coeff.	*MW/cumec*	4.85	4.98	5.10	5.24	5.38	5.46	5.59	5.68
Round-trip efficiency		*%*	**69.4%**	**70.2%**	**71.3%**	**72.3%**	**73.4%**	**73.6%**	**74.3%**	**74.5%**

The following turbine parameters are for an elevation of 695 masl and 608m of gross head:

Table 51: Lake Onslow (medium option) turbine parameters

Capacity	***MW***	**250**
Generation rated discharge rate per unit	*cumec*	51.4
Pumping maximum discharge per unit	*cumec*	39.0

In the following table is for sustained mode, and pumping efficiency includes 'lower' pumping up from the Clutha River to the lower reservoir (for the medium Lake Onslow option which has the lower reservoir Negotiations[62].

Table 52: Lake Onslow (medium option) pumphouse parameters

Turbines		***Units***	**2**	**3**	**4**
Maximum generate (turbined) flow		*cumec*	104	156	208
Maximum pump flow		*cumec*	78	117	156
Generation efficiency		*%*	84.2%	84.2%	84.2%
Pump efficiency		*%*	86.4%	86.4%	86.4%
Round trip efficiency	Average	*%*	71.0%	71.0%	71.0%
	When full	*%*	74.5%	74.5%	74.5%

[62] Values are based on Negotiation 1000MW, 10 Mm^3 lower reservoir volume option, so these numbers are slightly conservative for our medium 5 Mm^3 option, which has a maximum operating level 0.4m lower, but the difference is negligible.

8.4 Lower reservoir

The medium option for Lake Onslow is for a lower reservoir Negotiations The lower reservoir will be raised slightly above the level of the Clutha River, with 'lower' pumps used to fill it. During generating operation, the lower reservoir can be drawn down to river level.

Table 53: Lake Onslow (medium option) lower reservoir parameters

Lower reservoir size	*Mm3*	Commercial Information
Maximum operating level	*masl*	87
Max flow in (max harvest rate)	*cumec*	250
Lower pumps?		Yes

8.5 Transmission

Transmission assumptions for Lake Onslow are in addition to the generic transmission assumptions presented in section 7.

8.5.1 Grid connection

Transpower has developed, for early modelling purposes, a conceptual Lake Onslow grid connection comprising:

- A new Onslow substation on the surface above the powerhouse (which is deep underground), assumed some 40 Km south-east of Roxburgh substation
- Loop in, loop out connection of Onslow substation to all of the:
    - Invercargill – Roxburgh 1 and 2 circuits
    - Roxburgh – Three Mile Hill 1 and 2 circuits
- Dismantling the sections of those lines between the diversion points
- New Benmore – Onslow double circuit 220 kV line.

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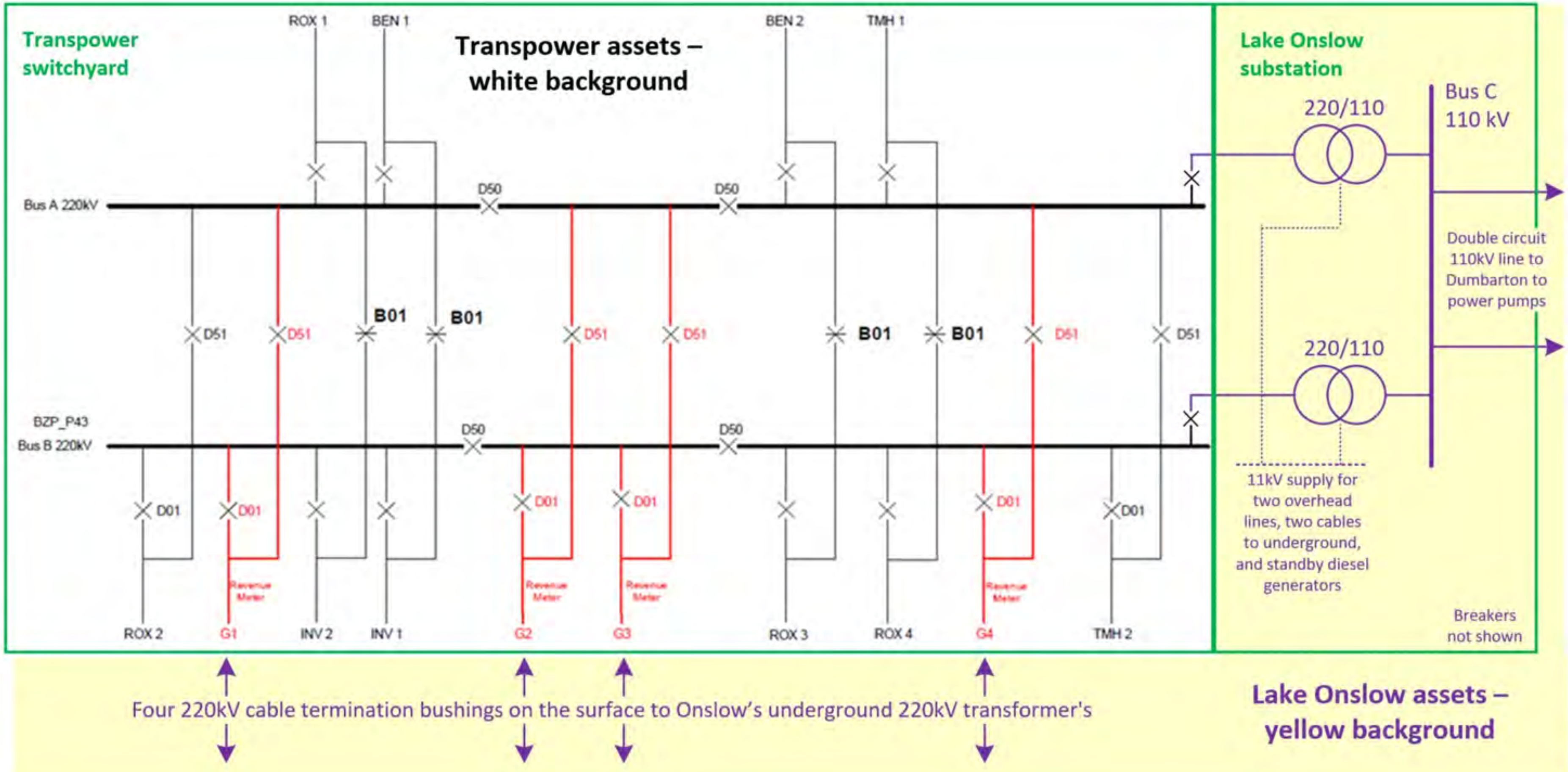
8.6 Scheme overview

Figure 16: Lake Onslow substation conceptual design bus configuration



We assume this conceptual grid connection design, with the following parameters. The relevant codes used here are:

- BEN Benmore
- INV Invercargill
- LO Lake Onslow
- ROX Roxburgh
- TMH Three Mile Hill (west of Dunedin)
- Circuits use suffixes 1, 2…
- Lines (one line of towers can carry one or two circuits) use suffixes A, B…
- Some names use here are not to industry standard and are placeholders to be refined as necessary in future.

Table 54: Lake Onslow local line and circuit changes

Line name		Type	Circuit(s) carried	Comments	Length
Existing	Proposed				
INV-ROX B	INV-LO B	Single circuit	INV-LO-ROX 2	Diversion in	6 km
INV-ROX B	INV-LO B	Double circuit	INV-LO-ROX 1 & 2	Diversion in	22 km
INV-ROX A	LO-ROX A	Double circuit	INV-LO-ROX 1 & 2	Diversion out	19 km
INV-ROX A	LO-ROX A	Single circuit	INV-LO-ROX 1	Diversion out	3 km
ROX-TMH A	LO-TMH A	Double circuit	ROX-LO-TMH 1 & 2	Diversion in	24 km
ROX-TMH A	LO-ROX B	Double circuit	ROX-LO-TMH 1 & 2	Diversion out	22 km
-	BEN -LO A	Double circuit	BEN-LO 1 & 2	New Build	220 km
INV-ROX B	-	Single circuit	INV-ROX 2	Removal of diverted sections	12 km
INV-ROX A	-	Single circuit	INV-ROX 1		11 km
ROX-TMH A	-	Double circuit	ROX-TMH 1 & 2		17 km

Table 55: Lake Onslow connection circuit parameters

	Summer	Winter	Shoulder	Voltage	R	X
	MVA	*MVA*	*MVA*	*kV*	*ohms*	*ohms*
INV-LO 1	347.1	382.2	365.0	220	7.61	48.52
INV-LO 2	347.1	382.2	365.0	220	7.43	48.54
LO-ROX 1	347.1	382.2	365.0	220	1.98	14.09
LO-ROX 2	347.1	382.2	365.0	220	2.05	14.93
LO-ROX 3	385.2	469.8	429.8	220	1.29	11.58
LO-ROX 4	385.2	469.8	429.8	220	1.29	11.58
LO-TMH 1	385.2	469.8	429.8	220	2.97	26.74
LO-TMH 2	385.2	469.8	429.8	220	2.97	26.74
BEN-LO 1	709.4	781.0	746.2	220	7.60	67.68
BEN-LO 2	709.4	781.0	746.2	220	7.60	67.68

8.6.1 HVAC North Island

We assume some additional transmission investments will be made, beyond those in the generic transmission assumptions presented in section 7, where the SDDP modelling and/or Transpower's power system analysis has indicated that they are likely to be economic. We assume these upgrades will be made by 2035, and by duplexing:

- Bunnythorpe-Haywards A and B (BPE-PRT-HAY 1 & 2), primarily to enable southward flow
- Bunnythorpe-Wairakei A (BPE-TNG-RPO-WRK), primarily to enable southward flow.

8.6.2 HVDC

We assume that the HVDC link capacity will not be upgraded beyond 1400MW, as to do so would require upgrade of the whole line including the lengthy overhead portions, and would create too great an extended contingent event (ECE) and potentially resilience risk.

We assume that, given that Lake Onslow pump will reduce spill from North Island wind and solar, the HVDC southwards flow will be maximised:

- Southwards flow will increase from 950MW (68% of 1400MW) to 1050MW (75%) with the Bunnythorpe-Haywards duplexing identified above
- Additional increase towards the 1400 MW technical maximum southwards, to 1300MW (93%) south, will be achieved with lower North Island voltage management, e.g. installation of dynamic reactive plant such as StatComs.

Transpower has cautioned that this assumed ability to increase of the HVDC link southwards capacity has not been studied and could, for example, raise issues for the Benmore-Twizel and/or Aviemore-Waitaki-Livingstone lines. Nevertheless we need an NZ Battery working assumption so – accepting that this will need detailed study if we are to proceed – we assume the above HVDC southwards expansion for modelling purposes.

8.6.3 HVAC South Island

Onslow when generating requires transmission capacity to be upgraded between the Roxburgh region and the Waitaki Valley. There are a number of options for this, and a detailed analysis will need to be undertaken of which option is most economic: we assume for modelling purposes that this will be achieved by:

- A new double-circuit 220 kV line from the Lake Onslow substation directly to Benmore
- Duplexing of the Aviemore-Benmore line, primarily to enable pumping.

Onslow when pumping may require grid support. To date, power system analysis of Onslow pumping has been limited to fixed speed synchronous turbines, but the Onslow design is based on variable speed turbines[63]. The Transpower analysis for synchronous turbines indicates that pumping under certain grid configurations, generation and load patterns, and pumping load combinations could breach system transient stability limits, and to maintain grid stability could require dynamic reactive plant of some 500 MVars (at a South Island site other than Onslow), possibly as synchronous condensers.

[63] To conduct such power system analysis, Transpower needs a DigSILENT model of the turbines, which TRM has provided for synchronous turbines but we do not yet have a model for variable speed turbines.

Variable speed turbines offer a transient response advantage compared to fixed speed synchronous turbines due to significantly faster dynamic response, and can offer enhanced system stability support. Therefore, it is expected that the additional reactive support required by the grid would be reduced where variable speed machines are used. Further, the cases of grid configurations, generation and load patterns, and pumping load combinations that place stability limits at risk are expected to be rare. Use of variable speed machines would allow the pumps to be unloaded to a safe pumping load without requiring the pumps to be shutdown. Such unloading may be facilitated by Special Protection Schemes or similar, so we have assumed:

- Special protection schemes (NZ Battery estimate).

This is an NZ Battery working assumption pending the full power system analysis by Transpower.

8.6.4 Summary of transmission assumptions

These are in addition to the generic transmission assumptions tabulated in section 7:

Table 56: Lake Onslow specific transmission assumptions

	Transmission investment specific to Lake Onslow	
Connection	Substation	Lake Onslow substation
	Circuits diverted into Onslow	Invercargill – Roxburgh A & B, Roxburgh – Three Mile Hill A
HVAC South Island	Increase transfer Roxburgh region to the Waitaki Valley	New Onslow to Benmore double-circuit 220 kV line
	Ensure grid stability when Onslow is pumping	Special protection schemes
HVDC	Increase southwards flow	1300 MW southwards
HVAC North Island	Bunnythorpe-Haywards 1 and 2	Duplexed
	Bunnythorpe-Wairaki 1	Duplexed
	Brownhill-Whakamaru 1 and 2	45% series compensation

8.7 Host system interaction

The Lake Onslow scheme would interact physically and possibly commercially with Contact Energy which owns and operates the Clutha River power system including the Lake Hawea control structure, Clyde Dam and Roxburgh Dam.

The SDDP model maximises national benefit, i.e. it finds a least cost dispatch, so implicitly assumes that Contact Energy and NZ Battery would be operating together for the national good.

9. NZ Battery Upper Moawhango pumped hydro option

The primary reference for this scheme is Stantec's Other Pumped Hydro and Other Hydro Options Initial Desktop Screening Study, prepared for MBIE, March 2022 (revision 3 of 23 May 2022), referred to as 'Site 1'.

9.1 Scheme overview

The scheme includes:

- Upper Moawhango reservoir with new dam to contain it
- Horizontal tunnel to a head-pond
- Tunnel from the headpond to an undergrpound pump/power station Commercial Information [redacted]

Commercial Information [redacted]

Table 57: Upper Moawhango summary of key parameters

Upper reservoir total storage	*Mm³*	1714
Upper reservoir live storage	*Mm³*	1199
Storage provided	*TWh*	2.75

The storage provided in the table above includes the energy provided from all downstream generation, owned by Genesis and Mercury.

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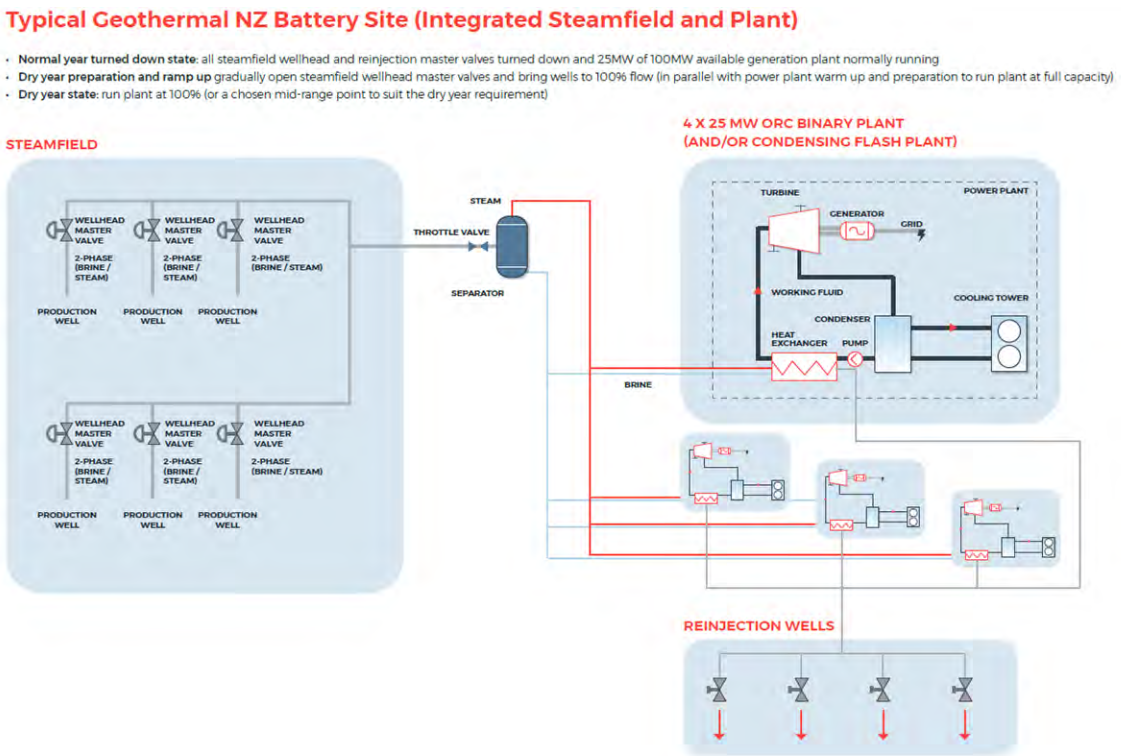
10. NZ Battery geothermal reserve option

10.1 Overview

Key features of the geothermal reserve option are based on those recommended by WSP and include:

- A total of 400 MW of new geothermal plant are developed, specifically designed to enable ramping flexibility
- Each plant will be 100 MW comprising four 25 MW units. One unit will always be operating in baseload. In an emerging dry year, wells are slowly de-throttled and the other generation units brought progressively online.
- It takes two weeks to ramp up to full capacity across all units, and the same time to ramp back down
- The plant are spread across several greenfield geothermal sites in the Taupo volcanic zone (the zone includes the south-eastern Waikato and central Bay of Plenty).

Figure 21: Geothermal reserve scheme overview (from WSP)



10.2 Modelling assumptions

Table 58: NZ Battery geothermal reserve modelling parameters

Capacity	**Baseload**	*MW*	100 MW
	Flexible	*MW*	300 MW
	Total	*MW*	400 MW
Ramp rate	**Up**	*MW / time*	150 MW / week
	Down	*MW / time*	150 MW / week
Location			Taupo volcanic zone
Operating mode			SOS Mode

For SOS Mode the hydro risk trigger used is the $80 MWh Waitaki water offer curve, reflecting the state of the major storage in the South Island.

The NZ Battery geothermal reserve, when modelled, requires geothermal resource which removes its availability to the market. It is assumed that the 400MW of geothermal reserve targets higher gross emissions fields first, to allow full baseload market geothermal plant preferential use of the lower emissions resources.

Given our 50% carbon reinjection success rate assumption, this means that the full 400 MW of low, medium and high emissions resource that does not have successful re-injection is used for geothermal reserve, and the fields with successful reinjection are used for market baseload geothermal, also totalling 400 MW. The geothermal reserve can then, for modelling convenience, be considered as a single emissions tranche with a weighted average emissions rate:

Table 59: NZ Battery geothermal reserve option emissions tranches

Emissions tranche		**Geothermal reserve capacity**	**Remaining market capacity**
Tranche	*Kg C / MWh*	*MW*	*MW*
Re-injection	0	-	400 MW
No re-injection average	100	400 MW	-

Geothermal is assumed to have zero base VOM, but will have a VOM reflecting the emissions and carbon charge:

Table 60: NZ Battery geothermal reserve VOM

		2021	**2035**	**2050**	**2065**
VOM excluding carbon charge	*$ / MWh*	0			
Emissions	*Kg C / MWh*	100			
VOM	*$ / MWh*	3	17	26	40

While there will be some start-up costs, we assume that start-ups occur sufficiently frequently that this in included as part of the FOM.

10.3 Transmission implications

Transmission export is required for four new 100MW geothermal generation stations, spread across several greenfield geothermal sites in the Taupo volcanic zone.

We assume each will require a connection substation, with an average of 10 to 20 Km of diversions of the nearest 220 kV line. Some of the geothermal generation stations could be close enough to a line to require no diversion, some required diversions could be longer.

Transpower has identified two upgrades that may be required in addition to those in its current NZGP, depending on geothermal reserve generation locations, the location of biomass option in a portfolio solution, and other market generation investments:

- Reconductoring the 115 Km Ohakuri-Edgecumbe-A line (as may be required for the biomass option)
- Reconductoring the 220 Km Bunnythorpe-Wairakei-A line.

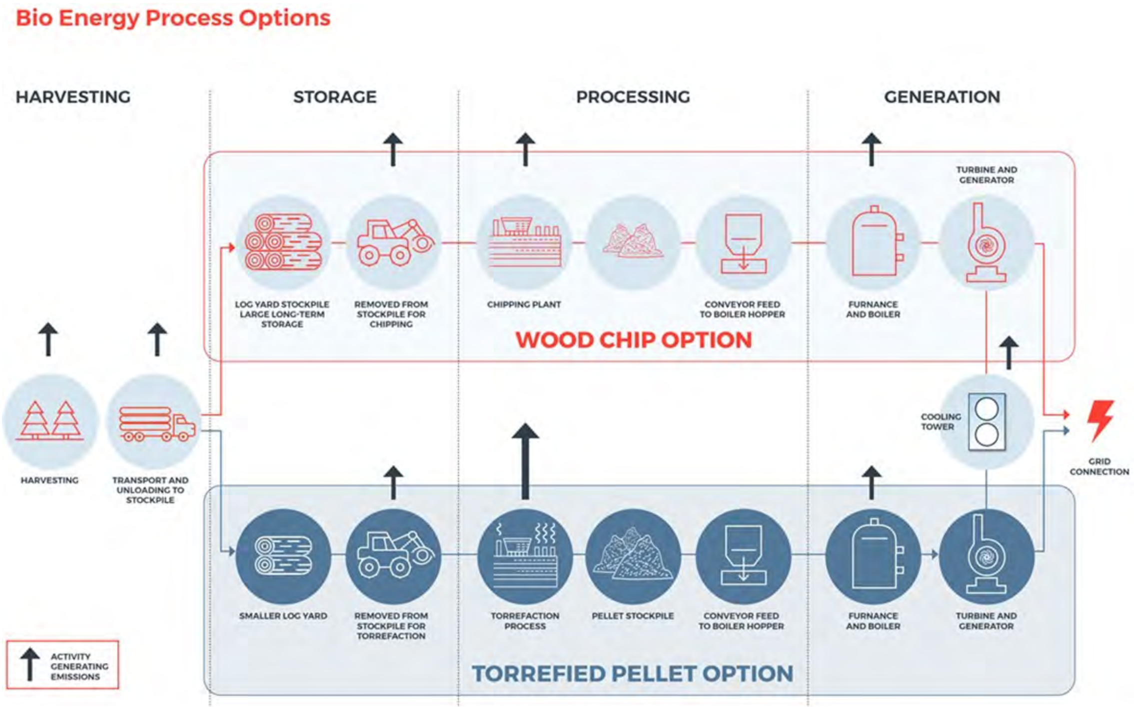
11. NZ Battery biomass option

11.1 Overview

Key features of the biomass option are based on those recommended by WSP, which are, converted to potential electrical terms where appropriate:

- A stockpile of white logs (debarked tree trunks) is kept at the generation site, with a stockpile when full sufficient for 1 TWh of generation output
- Logs are harvested and supplied to the stockpile at a steady rate of 1000 tonnes (about 46 trucks) daily through a routine supply contract. This daily rate can, with three months' notice, be flexed up by 50% through a combination of flex in the routine supply contract chain and purchasing ready-for-export logs
- There would be 500 MW of log-fired generation on site, consisting of two 250 MW Rankine cycle plant, for which the logs would be chipped 'just in time'
- The maximum lifetime of a log in the stockpile is three years, within which time they would need to be burned for generation or passed on to another, higher-value use
- An alternative option has been considered (illustrated below), which would utilise torrefied wood - a more heavily processed biomass fuel. However, this is not being modelled, to focus on the preferred option.
- The generation site would balance the proximity to the forest resource with the availability of land transport and transmission infrastructure. Many areas could be possible for this, but for modelling purposes we will assume a site in the central North Island.

Figure 22: Biomass scheme overview (from WSP)



11.2 Modelling assumptions

Table 61: Biomass scheme stock and flow modelling parameters

		Per **tonne of logs**	**Routine inflow**			**Maximum stockpile**
			Day	**Three months**	**Year**	
Log stockpile lifetime	*Years*					3
Log supply	*t*	1	1,000	91,000	370,000	1,100,000
Energy in logs	*GJ / t*	10.3				
Energy in gross	*MWh*	2.85	2,900	260,000	1,000,000	3,100,000
Chipping loss	*%*	0.18%				
Rankine efficiency	*%*	32%				
Potential generation	*MWh*	0.91	910	82,000	330,000	980,000

In addition to the routine supply as above, we assume that supply can be flexed up by 50% through diverting logs from other uses e.g. export. The costs and prices for routine and flex-up supply are shown below. Unused logs, which would almost always be from the routine supply after their three-year stock life, have a resale value.

Table 62: Biomass scheme SRMC

		Routine	Flex-up
Maximum per day	*t*	1000	500
Log price delivered	*$ / t*	$ 112	$ 136
VOM	*$ / MWh*	$ 3	
SRMC	*$ / MWh*	$ 120	$ 150

Table 63: Biomass scheme unused log resale price

Reduction relative to routine price	*%*	**40 %**
Unused log resale price	*$ / MWh*	$ 74

Table 64: Biomass scheme modelling parameters

Generation	500 MW
Location	North Island
Operating mode	Flexibility mode

In the NZ Battery biomass option, the standard market green peaker assumptions are used in addition.

11.3 Transmission implications

As noted above, the biomass generation site would balance the proximity to the forest resource with the availability of land transport and transmission infrastructure. Many areas could be possible for this, but for modelling purposes we assume a site in a plantation forest area of the central North Island, in the eastern Waikato or Southern Bay of Plenty region.

There will need to be a strong substation to support the 500 MW of generation, and we assume three possibilities for connecting this substation to the 220kV grid, accepting that there could be others:

- New 600MW double circuit line 220kV line of 50 Km to 70Km, to the Whakamaru or Wairakei substation
- Reconductoring the 115 Km Ohakuri-Edgecumbe-A line (as may be required for the geothermal reserve option).

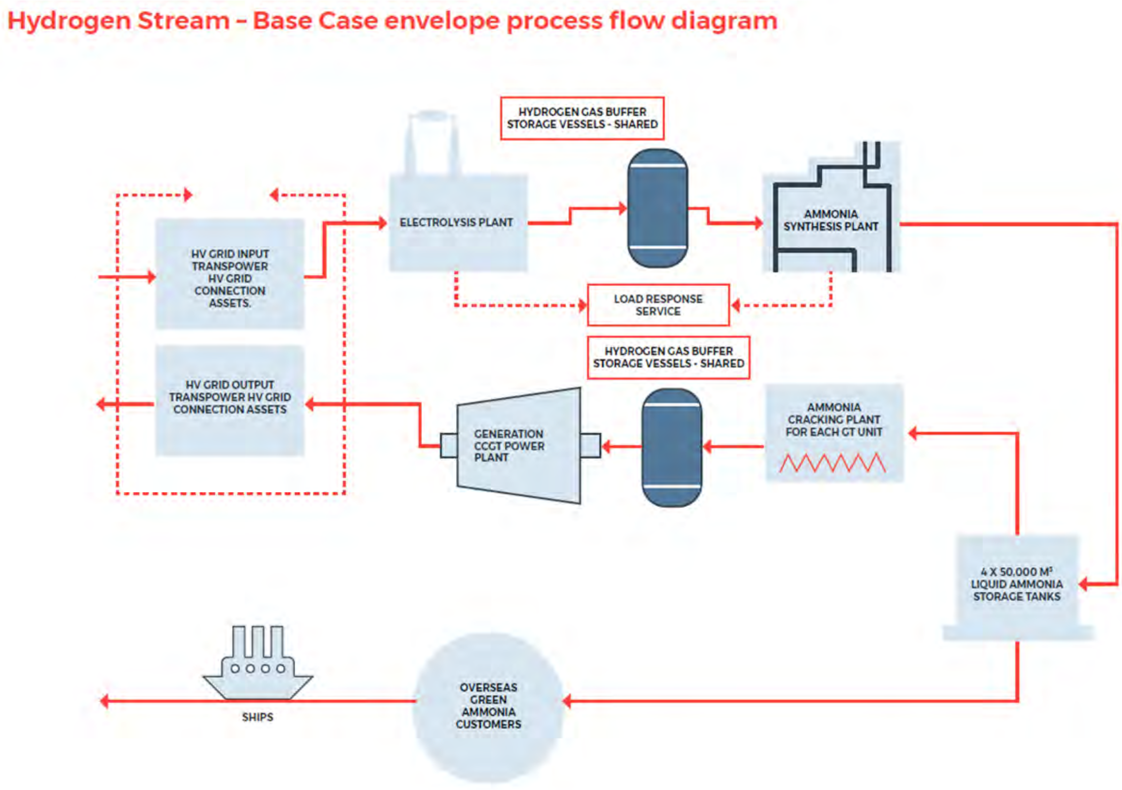
12. NZ Battery hydrogen and ammonia option

12.1 Overview

Key features of the hydrogen-ammonia option are based on those recommended by WSP in its Other Technologies Feasibility Study:

- Electrolysis of water into hydrogen using a fully flexible electrolyser, with buffer storage of hydrogen equivalent to about twelve hours of production at full electrolyser output
- Ammonia synthesis plant, sized to match the electrolyser plant hydrogen output. Ammonia production which can drop to part-load rapidly, or turn off with a two-day re-start time
- Bulk ammonia storage using above ground containment tanks, plus supplementary storage to support an export terminal
- Cracking of ammonia back into hydrogen to feed electricity generation through two 75 MW CCGT plants
- Most of the response is provided by turning off the electrolyser, but significant response also from the hydrogen-fuelled generation.

Figure 23: Hydrogen-ammonia scheme overview (from WSP)



12.2 Modelling assumptions

Table 65: Hydrogen-ammonia scheme cumulative efficiencies

		Energy from grid	Electrolysis	Hydrogen storage	Ammonia synthesis	Ammonia storage	Ammonia cracking	Hydrogen storage	Generation
Capacity	*MW*		350 MW		19 MW				150 MW
Efficiency	*%*		66%		84%		77%		60%
Via ammonia storage	*MWh*	369		231		194		149	90
	%	*100%*		*66%*		*53%*		*40%*	*24%*

The hydrogen-ammonia option provides for up to 200,000m^3 of liquid ammonia storage. This is equivalent to around 380 MWh of potential generation from the CCGT. Production is assumed to be stored and/or provided to the CCGT as priority. ‘Spill’ from continued production when storage is full is diverted to export (via supplementary storage).

In setting the electrolyser bid and CCGT offer prices into the electricity market, we have assumed:

- Export-parity pricing, given our assumption that excess green ammonia is exported
- A liquid market develops for this product by 2035
- A green ammonia price (distinct from costs):
  - Derived from IEA projections for green ammonia and international renewable electricity costs
  - Determined by the capability of technology investments made in 2030, with those investments being necessary to meet increasing demand for green ammonia - even as green ammonia production technology improves - and hence being the marginal price setter through-out our modelled period
  - Declining over time, on the assumption the price of the renewable energy used to produce it declines over time
- The international ammonia price informs the willingness to pay for electricity to produce it, reflecting
  - An exchange rate of 0.65 NZD/USD
  - The efficiency of the production process
  - An assumption that electricity comprises 90% of short-run marginal costs
- Similarly, the international ammonia price informs the CCGT offer price, adjusted for the exchange rate and cracking and generation efficiency.

This results in the bid and offer prices in the table below.

There is massive uncertainty around green ammonia prices into the future. The numbers below are far from definitive, but provide a reasoned estimate for modelling purposes, with the IEA references providing a touchstone.

Table 66: Hydrogen-ammonia scheme prices

		2035	2050	2065
International electricity input cost	*USD/MWh*	$ 60	$ 35	$ 25
International ammonia price (export)	*USD/t_{NH3}*	$ 750	$ 500	$ 400
Electrolyser bid price	*NZD/MWh*	$ 92	$ 61	$ 49
CCGT offer price	*NZD/MWh*	$ 400	$ 266	$ 213

12.3 Transmission implications

The hydrogen-ammonia option is assumed to be located close to a port and transmission. Transmission is required to service a range between a 370 MW load and 150 MW generation.

13. NZ Battery portfolio options

The NZ Battery portfolio options are to explore a portfolio of the other three options (geothermal reserve, biomass, and hydrogen-ammonia) as:

- Individual options are size- or capability-constrained in meeting the range of dry year scenarios that could unfold
- If the Government were to procure such options, it may be through a form of technology-agnostic tender process, with a combination of solutions as a likely or at least possible outcome
- A portfolio might also reflect a market or regulated provision of such services, or some combination thereof.

For modelling, we consider the following three portfolio options:

Table 67: Portfolio options considered

Portfolio	Geothermal reserve	Biomass	Hydrogen-ammonia	NZAS load curtailment	Gross benefit relative to:
1	✓	✓	✓	×	Counterfactual (Tiwai out)
2	✓	✓	×	✓	NZAS-in base case
3	✓	✓	×	×	Counterfactual (Tiwai out)

Portfolio 1 includes all three individual non-hydro NZ Battery options identified.

Portfolio 2 explores how a portfolio solution might change if NZAS remains in:

- NZAS already has a load curtailment capability, of some 80 MW for 130 days

- We assume that this level of response will continue in the 'NZAS-in' base case
- In Portfolio 2, we assume also that NZ Battery has contracted with NZAS for the same magnitude of response but triggered at a lower risk level.
- For NZAS load curtailment response trigger we use the Waitaki water offer curve, reflecting the state of the major storage in the South Island, at the $500 level for the NZAS-in base case, and at the $250 level for Portfolio 2 (this is the same SOS Mode approach used for geothermal reserve, but with higher prices for more conservative operation).

Portfolio 3 has neither the hydrogen-ammonia nor NZAS load curtailment present, to explore the value of significant demand response in a portfolio solution.

14. Generation investment stacks

This section presents our assumptions on specific generation investment and retirements. These are used explicitly in the SDDP modelling, and inform some of the generic generation assumptions.

14.1 Fossil fuel retirement

Table 68: Fossil fuel generation retirement assumptions (SDDP)

Plant	Type	Capacity (MW)	Retirement year (1 January)
Taranaki Combined Cycle	CCGT	380	2025
Huntly C1	Coal/Gas Steam turbine	243	2025
Huntly C2	Coal/Gas Steam turbine	243	2025
Huntly C4	Coal/Gas Steam turbine	243	2025
Whirinaki	Diesel	155	2029
McKee	OCGT	100	2033
Edgecumbe	Cogeneration	10	2033
E3p	CCGT	403	2035
Huntly P40	OCGT	50	2035
Stratford Open Cycle Gas Turbine	OCGT	200	2035
Junction Road	OCGT	100	2035
Bream Bay Peaker	Diesel	9	2035

14.2 Wind

Wind specific generation opportunities assumptions use the generic CAPEX (with transmission CAPEX added), FOM and VOM from section 3.2, and add:

Table 69: Wind specific generation opportunities assumptions

Name	Capacity	Location	Available	Transmission costs	
	Max MW	*GIP*	*Start of year*	*$/kW*	*$M*
Turitea	221.4	LTN220	2022 fixed	212	47
Harapaki	176.3	WRK220	From 2023	165	29
MtCass	92.4	WPR066	From 2023	115	11
Puketoi	300	LTN220	From 2025	444	133
CastleHill	500	LTN220	From 2026	220	110
KaiwDwns	200	NMA220	From 2025	203	41
Awhitu	25	HLY220	From 2025	141	4
CentralWind	150	BPE220	From 2025	293	44
MtMunro	100	MGM110	From 2026	250	25
Waitahora	150	LTN220	From 2026	490	73
KaimaiWind	100	HAM110	From 2026	186	19
Flemington	100	FHL110	From 2026	340	34
Mahiner_s2	150	HWB220	From 2026	321	48
Hurunui	80	ISL220	From 2026	567	45
BOPTaupo_1	300	TRK220	From 2026	102	31
Kaiwaikawe	75	MPE110	From 2026	103	8
Northland_1	300	MDN220	From 2026	484	145
Waikato_1	180	OHW220	From 2026	434	78
Waikato_2	200	OHW220	From 2026	355	71
Marlboroug_1	50	BLN110	From 2026	201	10
Wellington_1	15	WIL220	From 2026	341	5
Manawatu_1	150	BPE220	From 2026	381	57
BOPTaupo_2	300	WRK220	From 2026	100	30
Wellington_2	100	HAY220	From 2026	261	26
Auckland_1	100	HPI220	From 2026	509	51
Manawatu_2	150	BPE220	From 2026	246	37
Auckland_2	100	HPI220	From 2026	312	31
Northland_2	150	MDN220	From 2026	260	39
CentralPla_1	250	TKU220A	From 2026	118	30
BOPTaupo_3	150	WRK220	From 2026	285	43
Eastland_1	50	TUI110	From 2026	65	3
Northland_3	100	MDN220	From 2026	319	32

Name	Capacity	Location	Available	Transmission costs	
	Max MW	*GIP*	*Start of year*	*$/kW*	*$M*
BOPTaupo_4	100	WRK220	From 2026	603	60
Southland_1	100	NMA220	From 2026	219	22
BOPTaupo_5	75	WRK220	From 2026	320	24
FarNorth_1	75	MDN220	From 2026	454	34
Otago_1	500	ROX220	From 2026	166	83
Waikato_3	20	WRK220	From 2026	256	5
Southland_2	25	NMA220	From 2026	441	11
FarNorth_2	75	MDN220	From 2026	487	36
Eastland_2	75	TUI110	From 2026	691	52
Southland_3	150	NMA220	From 2026	200	30
Waikato_4	50	WKM220	From 2026	361	18
Wairarapa_1	100	MGM110	From 2026	582	58
Eastland_3	200	TUI110	From 2026	508	102
Otago_2	300	HWB220	From 2026	186	56
Manawatu_3	150	BPE220	From 2026	144	22
Southland_4	100	NMA220	From 2026	348	35
BOPTaupo_6	75	WRK220	From 2026	498	37
Marlboroug_2	75	BLN110	From 2026	392	29
Southland_5	50	NMA220	From 2026	492	25
SouthernWa_1	100	BPE220	From 2026	433	43
Southland_6	150	NMA220	From 2026	449	67
CentralPla_2	150	TNG220	From 2026	192	29
Southland_7	100	NMA220	From 2026	529	53
FarNorth_3	200	MDN220	From 2026	545	109
Waikato_5	75	WKM220	From 2026	115	9
Canterbury_1	15	ISL220	From 2026	384	6
Otago_3	150	HWB220	From 2026	210	31
BOPTaupo_7	10	ARI110A	From 2026	774	8
WestCoast_1	75	DOB110	From 2026	353	26
Northland_4	100	MPE110	From 2026	639	64
Otago_4	150	HWB220	From 2026	634	95
BOPTaupo_8	150	WRK220	From 2026	195	29
Northland_5	150	MDN220	From 2026	348	52

Name	Capacity	Location	Available	Transmission costs	
	Max MW	*GIP*	*Start of year*	*$/kW*	*$M*
Manawatu_4	100	BPE220	From 2026	362	36
Canterbury_2	150	ISL220	From 2026	479	72
Canterbury_3	100	ISL220	From 2026	647	65
Eastland_4	150	TUI110	From 2026	1110	166
CentralPla_3	125	TKU220A	From 2026	618	77
Taranaki_1	100	SFD220	From 2026	279	28
Wellington_3	100	LTN220	From 2026	321	32
Taranaki_2	200	SFD220	From 2026	224	45
Northland_6	100	MDN220	From 2026	207	21
Auckland_3	125	HLY220	From 2026	363	45
SouthernWa_2	150	BPE220	From 2026	422	63
HawkesBay_1	100	RDF220	From 2026	373	37
Auckland_4	150	HLY220	From 2026	392	59
Canterbury_4	200	ISL220	From 2026	247	49
Taranaki_3	200	SFD220	From 2026	173	35
Manawatu_5	300	BPE220	From 2026	110	33
TOTAL	**11,285**				

14.2.1 Repowering of existing wind farms

In our time horizon, we can expect many existing wind-farms to be repowered, probably with a higher capacity as technology advances.

Table 70: Wind specific repowering assumptions

Name	Capacity	Location	Available	Transmission	
	Max MW	*GIP*	*Start of year*	*$/kW*	*$M*
MillCrk_Rpwr	105	WIL220	2044 fixed	35	4
TaraW1_Rpwr	100.8	BPE220	2029 fixed	35	4
TaraW2_Rpwr	140	LTN220	2034 fixed	35	5
TaraW3_Rpwr	125	TWC220	2037 fixed	35	4
TeApiti_Rpwr	220	WDV110	2034 fixed	35	8
TRrHau_Rpwr	82	TWC220	2041 fixed	35	3
TRrHau3_Rpwr	82	TWC220	2041 fixed	35	3
TRrHau4_Rpwr	81	TWC220	2041 fixed	35	3
TeUku_Rpwr	110	HAM110	2041 fixed	35	4
WstWnd_Rpwr	250	WIL220	2039 fixed	35	9
Mahiner_Rpwr	50	HWB220	2041 fixed	35	2
WhtHll_Rpwr	115	NMA220	2037 fixed	35	4

14.3 Utility solar

Utility solar specific generation opportunities assumptions use the generic CAPEX, FOM and VOM from section 6.4.1, and add:

Table 71: Utility solar specific generation opportunities assumptions

Name	Capacity	Location	Available
	Max MW	*GIP*	*Start of year*
Solar_OHA_1	200	OHA220	From 2025
Solar_OHC_1	200	OHC220	From 2025
Solar_OHB_1	200	OHB220	From 2025
Solar_BEN_1	200	BEN220	From 2025
Solar_AVI_1	200	AVI220	From 2025
Solar_STK_1	200	STK066	From 2025
Solar_KAW_1	200	KAW110	From 2025
Solar_CYD_1	200	CYD220	From 2025
Solar_WHI_1	180	WHI220	From 2025
Solar_ARG_1	100	ARG110	From 2025
Solar_BLN_1	140	BLN110	From 2025
Solar_TWH_1	200	TWH220	From 2025
Solar_GLN_1	200	GLN220	From 2025
Solar_ASB_1	200	ASB066	From 2025
Solar_WTU_1	200	WTU220	From 2025
Solar_RDF_1	200	RDF220	From 2025
Solar_BOB_1	200	BOB110	From 2025
Solar_WHU_1	120	WHU110	From 2025
Solar_HUI_1	120	HUI110	From 2025
Solar_SVL_1	200	SVL220	From 2030
Solar_ISL_1	200	ISL066	From 2030
Solar_ISL_2	200	ISL066	From 2030
Solar_ISL_3	200	ISL066	From 2030
Solar_MAN_1	200	MAN220	From 2030
Solar_LTN_1	160	LTN220	From 2030
Solar_BPE_1	160	BPE220	From 2030
Solar_HLY_1	200	HLY220	From 2030
Solar_HLY_2	200	HLY220	From 2030
Solar_KPU_1	120	KPU066	From 2030
Solar_BRB_1	120	BRB220	From 2030
Solar_TNG_1	120	TNG220	From 2030

Name	Capacity	Location	Available
	Max MW	*GIP*	*Start of year*
Solar_OAM_1	120	OAM110	From 2030
Solar_TMK_1	100	TMK110	From 2030
Solar_WRK_1	100	WRK220	From 2030
Solar_CUL_1	60	CUL220	From 2030
Solar_ASY_1	80	ASY066	From 2030
Solar_HWB_1	200	HWB110	From 2030
Solar_MST_1	120	MST110	From 2030
Solar_HAM_1	200	HAM220	From 2030
Solar_BRY_1	200	BRY066	From 2030
Solar_FKN_1	140	FKN110	From 2030
Solar_ARI_1	100	ARI110A	From 2030
Solar_HIN_1	60	HIN110	From 2030
Solar_NMA_1	120	NMA220	From 2034
Solar_INV_1	200	INV220	From 2034
Solar_TKR_1	180	TKR110	From 2034
Solar_CST_1	140	CST110	From 2034
Solar_TMU_1	80	TMU110	From 2034

14.4 Geothermal

Geothermal specific generation opportunities assumptions use the generic CAPEX, FOM and VOM from section 6.5, and add:

Table 72: Geothermal specific generation opportunities assumptions

Name	Capacity	Location	Available	Emissions
	Max MW	*GIP*	*Start of year*	*Kg C / MWh*
Tauhara2a	168	WRK220	2021 fixed	61
Tauhara2b	82	WRK220	2026 fixed	61
Ngawha4	25	KOE110	From 2031	0
Mangakino	25	WKM220	From 2030	0
Mokai4	25	WRK220	From 2030	61
Ngatamariki2	50	WRK220	From 2030	61
Rotokawa3	50	WRK220	From 2030	61
Kawerau2	50	KAW220	From 2030	0
Rotoma1	25	EDG220	From 2030	0
TokaanuGeo1	20	TKU220A	From 2030	0
Tikitere1	50	TRK220	From 2030	0
Taheke1	25	EDG220	From 2030	0
Reporoa1	25	WRK220	From 2030	0
Tauhara3	30	WRK220	From 2034	61
Horohoro	5	TRK220	From 2034	0
AtiamuriGeo	5	ATI220	From 2034	0
Rotokawa4	50	WRK220	From 2034	0
TokaanuGeo2	100	TKU220B	From 2034	116
Tikitere2	50	TRK220	From 2034	116
Taheke2	25	TRK220	From 2034	0
Reporoa2	25	WRK220	From 2034	116
Ngawha5	25	KOE110	From 2034	0
Taheke3	25	TRK220	From 2034	116
Reporoa3	25	WRK220	From 2034	116
Ngawha6	25	KOE110	From 2034	0
TOTAL	**1010**			

14.5 Green peakers

Green peaker specific generation opportunities assumptions use the generic CAPEX, FOM and VOM from section 6.6, and add:

Table 73: Green peaker specific generation opportunities assumptions

Name	Capacity	Location	Available
	Max MW	*GIP*	*Start of year*
HLY_BioPkr1	500	HLY220	For 2035
SFD_BioPkr	200	SFD220	From 2035
OTOBioPkr_s1	120	OTO220	From 2030
OTOBioPkr_s2	120	OTO220	From 2030
OTOBioPkr_s3	120	OTO220	From 2030
HLY_BioPkr2	1000	HLY220	From 2035
TOTAL	**2060**		