Estimated gross benefits of NZ Battery options

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Executive summary

Purpose

- This report sets out estimates of gross benefits for generic energy storage schemes (referred to as 'NZ Battery' options) defined in terms of their storage size ('tank'), maximum output ('tap'), location in the North or South Island, and round-trip efficiency (% of input energy which is returned to the grid)

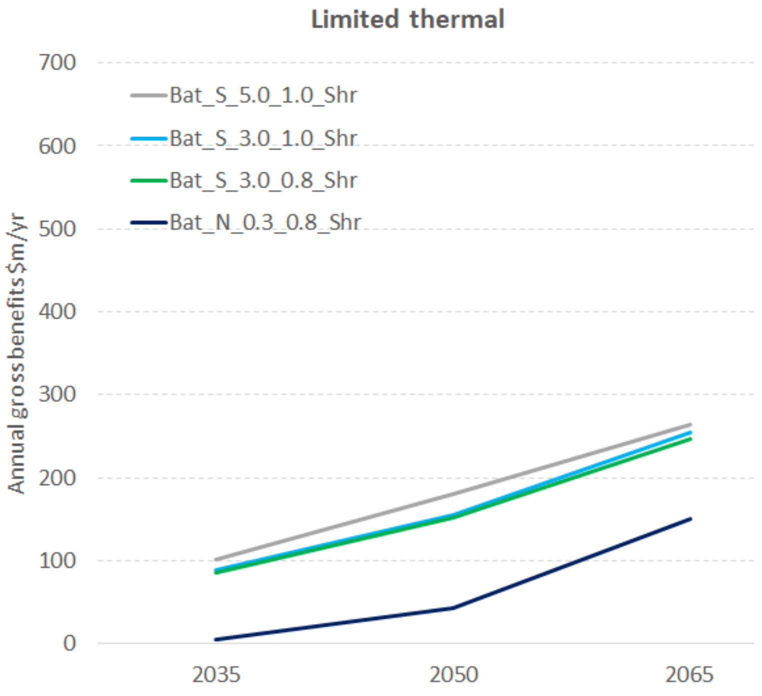
Approach

- Gross benefits are measured at the national level based on the change in total system cost enabled by each NZ Battery option
- System costs include the capital costs for new generation and smaller-scale batteries, fuel and carbon costs, and the costs of demand response
- Gross benefits are formally estimated for three representative years: '2035' (early in project life but after any 'fill' period), '2050' (when decarbonisation has lifted non-Tiwai electricity demand by around 50%) and '2065' (when electricity demand has almost doubled)
- We use these representative years to estimate gross benefits for the NZ Battery schemes with assumed 60-year economic lives. Gross benefit estimates for years between 2035, 2050 and 2065 are based on interpolations. Gross benefits beyond 2065 are assumed to be constant in real terms.
- Gross benefits are estimated under three future 'worlds': 'Limited thermal' (around 98% renewable), '100% Renewables' (no peakers), '100% Renewable with green peakers' (allowing for use of a biofuel or green hydrogen)
- We do not calculate any estimates of net benefits because we do not have information on the costs of different NZ Battery options

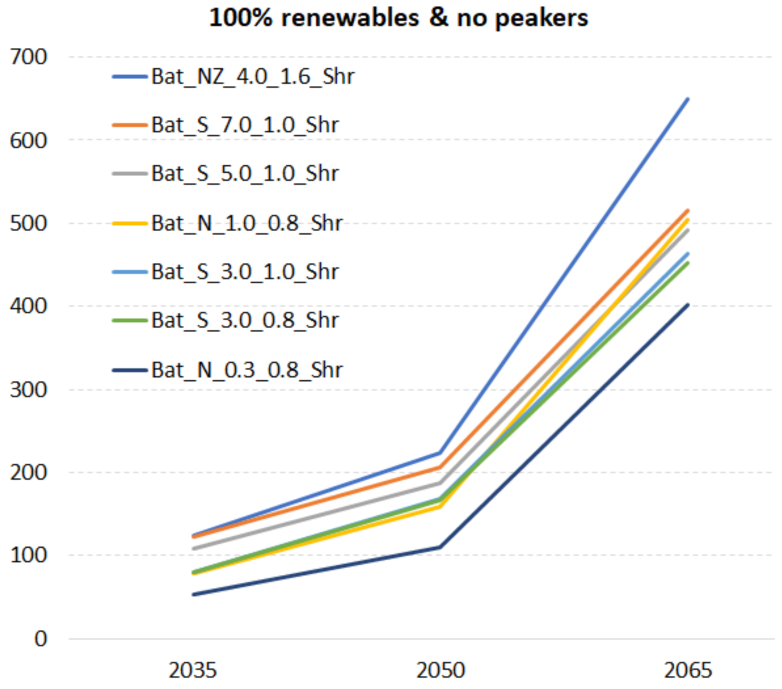
Executive summary - results

Gross benefits from NZ Battery increase over time as system growth increases the need for firming of seasonal and intermittent generation sources – and vary substantially depending on which 'world' applies

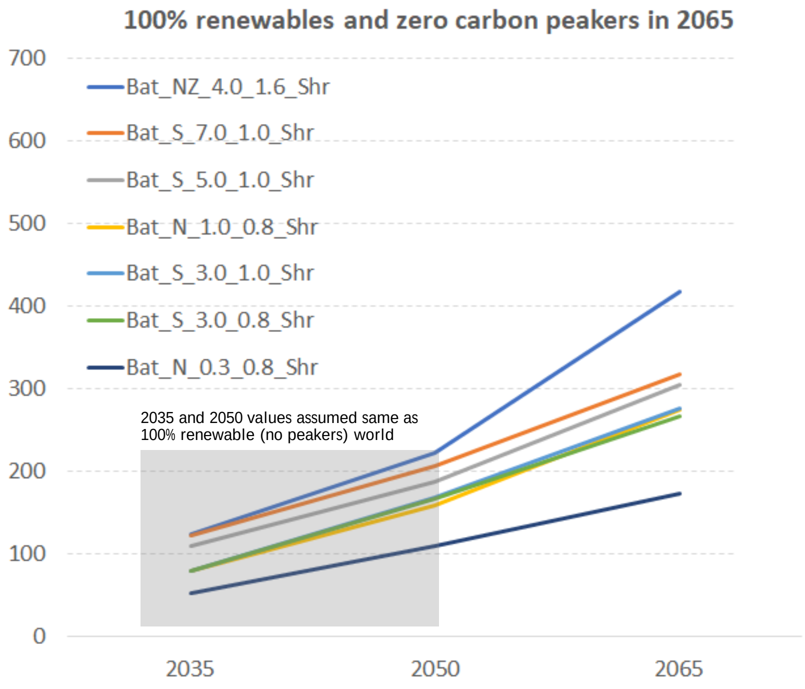
Limited thermal world assumes all baseload thermal retires by 2035 and only peakers remain - with fuel/carbon rising from $14/GJ to $35/GJ



100% renewables (no peakers) world assumes all thermal is retired by 2035 including peakers



100% renewables + green peakers world is same as 100% renewables world, except it assumes by 2065 there are zero carbon fuels at $45/GJ and it includes peaker capex



Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

Gross benefits from NZ Battery in the Limited Thermal world increase over time - but are reduced by presence of fossil fuelled peakers (paying carbon charges) as these also provide flexibility services. The effect is particularly noticeable for the NZ Battery option in the North Island

NZ Battery provides more benefits in '100% renewables (no peakers) world' - although difference is modest in 2035 and 2050. By 2065 NZ Battery provides significantly more benefit - reflecting projected growth in intermittent renewables and consequent greater need for flexible supply

Much of the benefit of NZ Battery in 2065 rests on assumption that no other large-scale zero carbon flexibility options will exist. As discussed later, it seems likely that zero carbon peakers will be available at $45/GJ (or less). This reduces benefits of NZ Battery in 2065

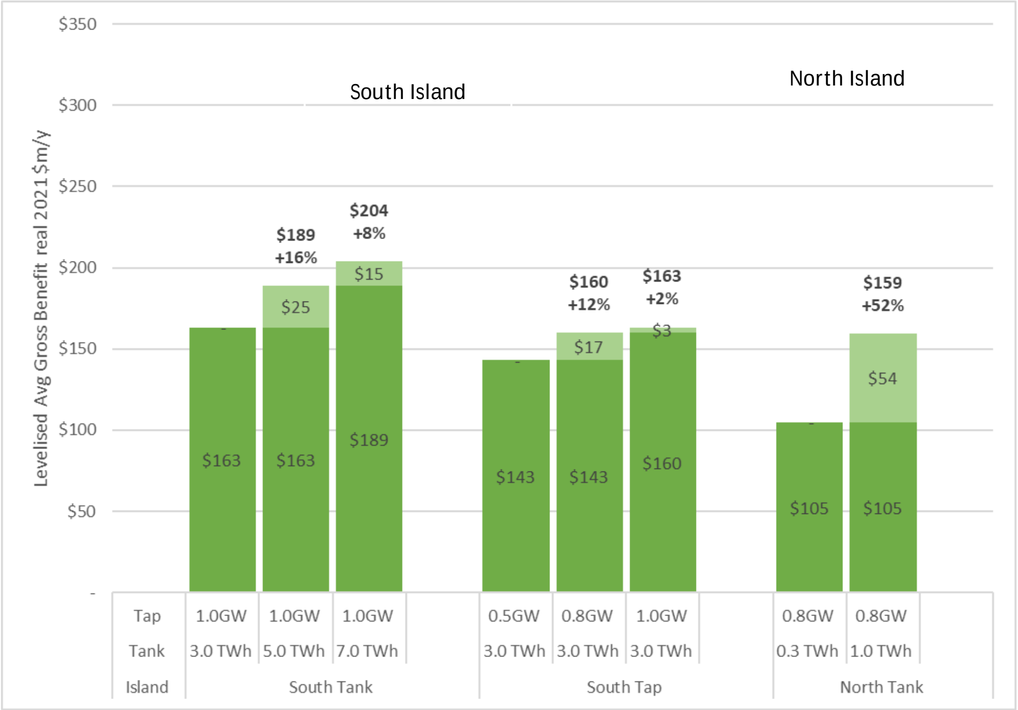
We regard '100% Renewable with green peakers' as the most appropriate 'world' for assessing gross benefits assuming New Zealand achieves 100% renewable generation – this is because there are reasonable grounds to expect zero-carbon fuel to be available in 2065 at $45/GJ or less (see later detail)

Executive summary - results

Gross benefits for South Island options do not vary greatly with tap or tank size above a combination 3 TWh/0.8GW. NI storage capacity has appreciable gross benefits if technically feasible

- Gross benefits for SI options are not strongly correlated with tank or tap sizes above a combination of 3 TWh/0.8 GW
- For example, increasing tank size from 3 TWh to 7 TWh (+133%) lifts gross benefit by 24%. Similarly, increasing tap size from 0.8 GW to 1.0 GW (+25%) lifts gross benefit by 2%
- Gross benefits for NI options are more strongly correlated with tank size
- For example, increasing tank size from 0.3 TWh to 1.0 TWh (+233%) lifts benefit by 52%, assuming a tap of 0.8 GW in each case (to be comparable with SI option)
- If technically feasible, a North Island Battery would have appreciable gross benefits - for example a 1 TWh 0.8 GW NI scheme provides similar gross benefits to a SI scheme that has three times the storage

Gross benefit of SI and NI schemes (100% Renewable + Green Peakers)

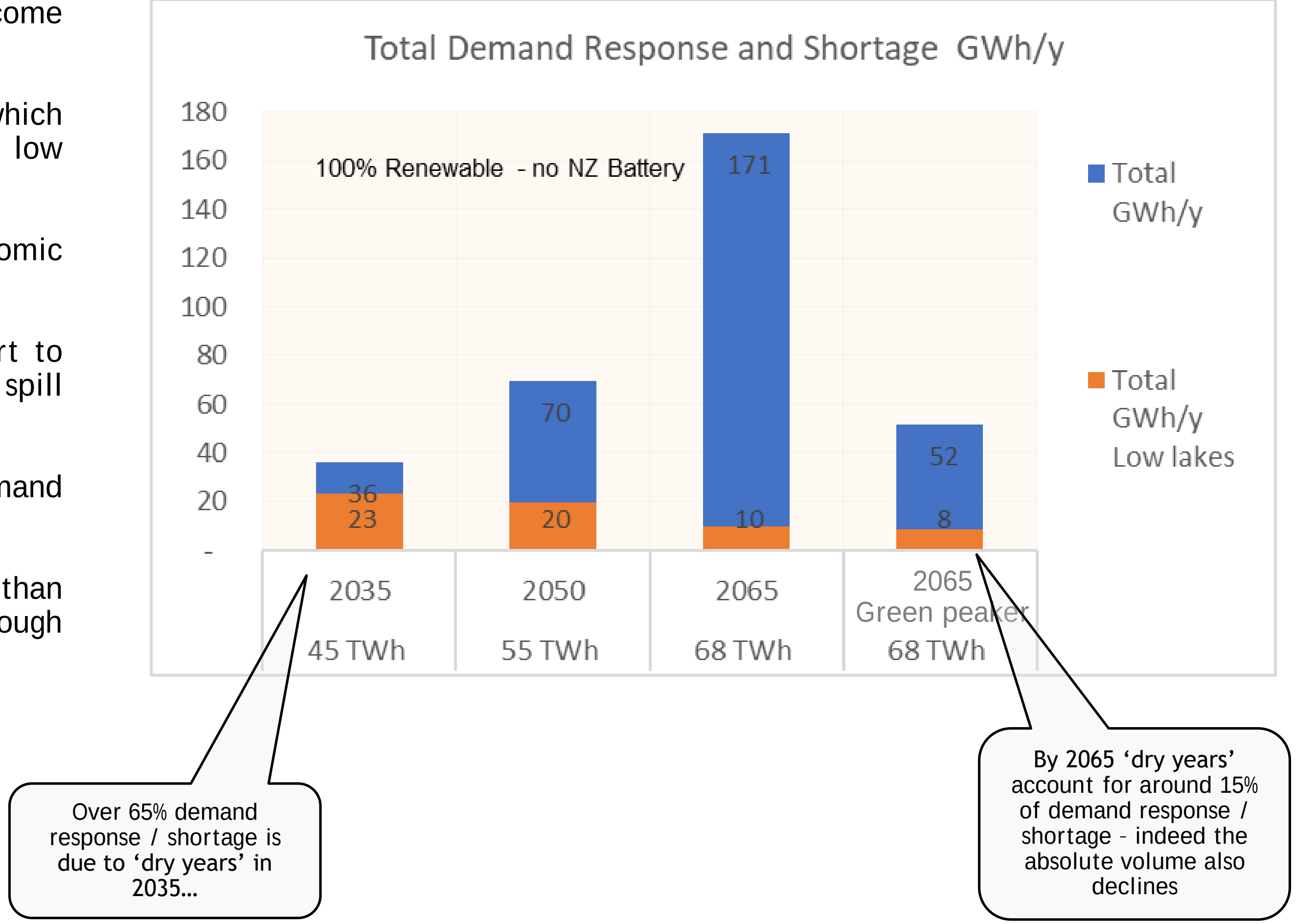


Notes: Figures are for the 100% renewable + green peakers world. Gross benefits are expressed in levelised terns for ease of comparison (see later for detail). Figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode].

Executive summary - **NZ’s storage needs change over time**

NZ’s storage requirements will progressively change as the nation decarbonises - shorter term flex will become increasingly important and the need for longer cycle ‘dry year’ flex will decline in relative (and absolute) terms

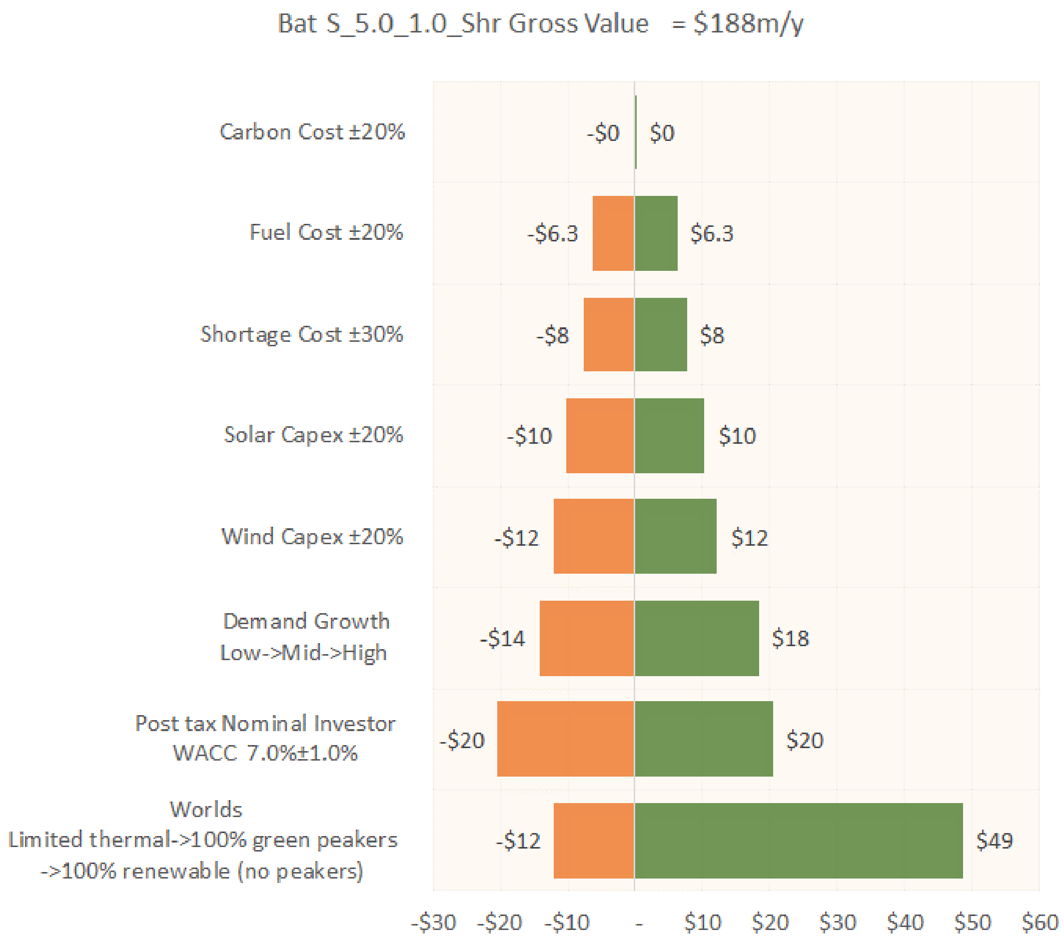
- By 2065, the majority of total electricity production is projected to come from wind and solar generation
- This means NZ’s system will become more like that of Germany - in which the challenge is *dunkelflaute* events - calm/dark periods with low wind/solar generation
- To achieve capacity adequacy in this type of system, it will be economic (i.e. necessary) to have significant levels of renewable ‘overbuild’
- Indeed, the overbuild is expected to become sufficiently large to start to shrink the dry year challenge - basically dry years will cause wind/solar spill to decline rather than manifesting as energy shortages
- This phenomenon is evident by the comparing the causes of demand response in the modelled results (see chart)
- This dynamic also explains why benefits are driven more by tap size than tank size - since big taps are more useful than big tanks for getting through ‘dunkelflaute’ events



Executive summary - results

Peaker fuel costs, the rate of demand growth, and cost of capital are the variables with greatest effect on gross benefits

- We have varied key inputs to test their effect on estimated gross benefits
- The inputs with greatest effects:
  - Peaker fuel costs - levelised gross benefits decline by $12 m/yr if peakers can use fossil fuel and pay carbon charges ('Limited thermal' world). Gross benefits increase by $49 m/yr if peakers cannot operate on zero-carbon fuel ('100% Renewable no peaker world')
  - Rate of demand growth - levelised benefits decline by $20 m/yr if it takes five years longer to reach the demand projected for 2050, 2065 etc. Gross benefits increase by $20 m/yr if demand levels projected for 2050, 2065 etc are reached five years earlier
  - Investor post tax nominal WACC - levelised benefits increase by $14 m/yr if WACC is higher by 1%. Gross benefits decline by $18 m/yr if WACC is lower by 1%
- Gross benefit estimates are also sensitive to assumptions regarding generation capital and fuel costs, demand response costs, and carbon charges - but these have less effect on overall gross benefits than the variables noted above



Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). Central estimate is levelised gross benefit for SI scheme with 3 TWh of storage and 1 GW of capacity in 100% Renewable + Green Peakers world

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Analytical question and methodology

Analytical question and how we address it

The analytical question

- We have been asked to identify the preferred target configuration for the 'NZ Battery' to achieve reliable power supply in a system with 100% renewable electricity
- The target configuration characteristics to be considered include:
  - Storage capability (GWh)
  - Discharge/recharge capacity (MW)
  - Location (South or North Island or both)

How we address the question

- The preferred target configuration will be the NZ Battery option with the greatest net benefits (i.e. gross benefits minus costs)
- However, we have no detailed information on costs of building and operating different NZ Battery options
- For this reason, we are unable to identify an optimal NZ Battery configuration
- Rather, we estimate the gross benefits of different NZ Battery options
- These gross benefit results can be used in future business case analysis for NZ Battery once cost information is available
- The gross benefit results also provide useful information to help target future effort

What do we mean by gross benefits of NZ Battery?

- Gross benefits are defined as the savings in total electricity system costs arising from a given NZ Battery option
- These savings are estimated by considering the difference in total electricity system costs between in two scenarios:
  1. NZ Battery is already built, filled and available
  2. NZ Battery option is not built
- In both scenarios we identify the least cost mix of generation and demand response - i.e. we take the role of a cost minimising system planner
- Our total system cost estimates:
  - include capital costs for construction of new generation and small-scale batteries (i.e. not NZ Battery)
  - include cash operating costs for new generation and smaller scale batteries and carbon charges (e.g. for geothermal)
  - include demand response costs - both voluntary and involuntary
  - exclude capital costs for existing generation which is likely to continue in operation (since capex for these is already sunk)
  - exclude transmission costs because the grid is assumed to be the same in the scenarios with and without NZ Battery
  - exclude the cost of building and initially filling ('charging') NZ Battery as both are currently unknown
  - include the cost of refilling NZ Battery once it is operating - noting this cost is embedded in the capital cost for new generation (some of whose energy is used to fill NZ Battery and cover its recharge/transfer losses)
- The resulting differences in estimates represent the national economic benefits of NZ Battery

Note: Capital costs are annualised costs using a capital recovery factor based on a 7% post tax nominal weighted average cost of capital, and economic life and construction cost profile. This capital recovery factor is close to an annuity based on a 6% pre tax real rate. Carbon prices in 2021 $ terms follow the CCC assumptions of $160/t, $250/t and $390/t in 2035, 2050 and 2065. We assume some additional within-island transmission will be built to enable new renewables to connect, but these costs are not quantified.

We model the system in three representative future years

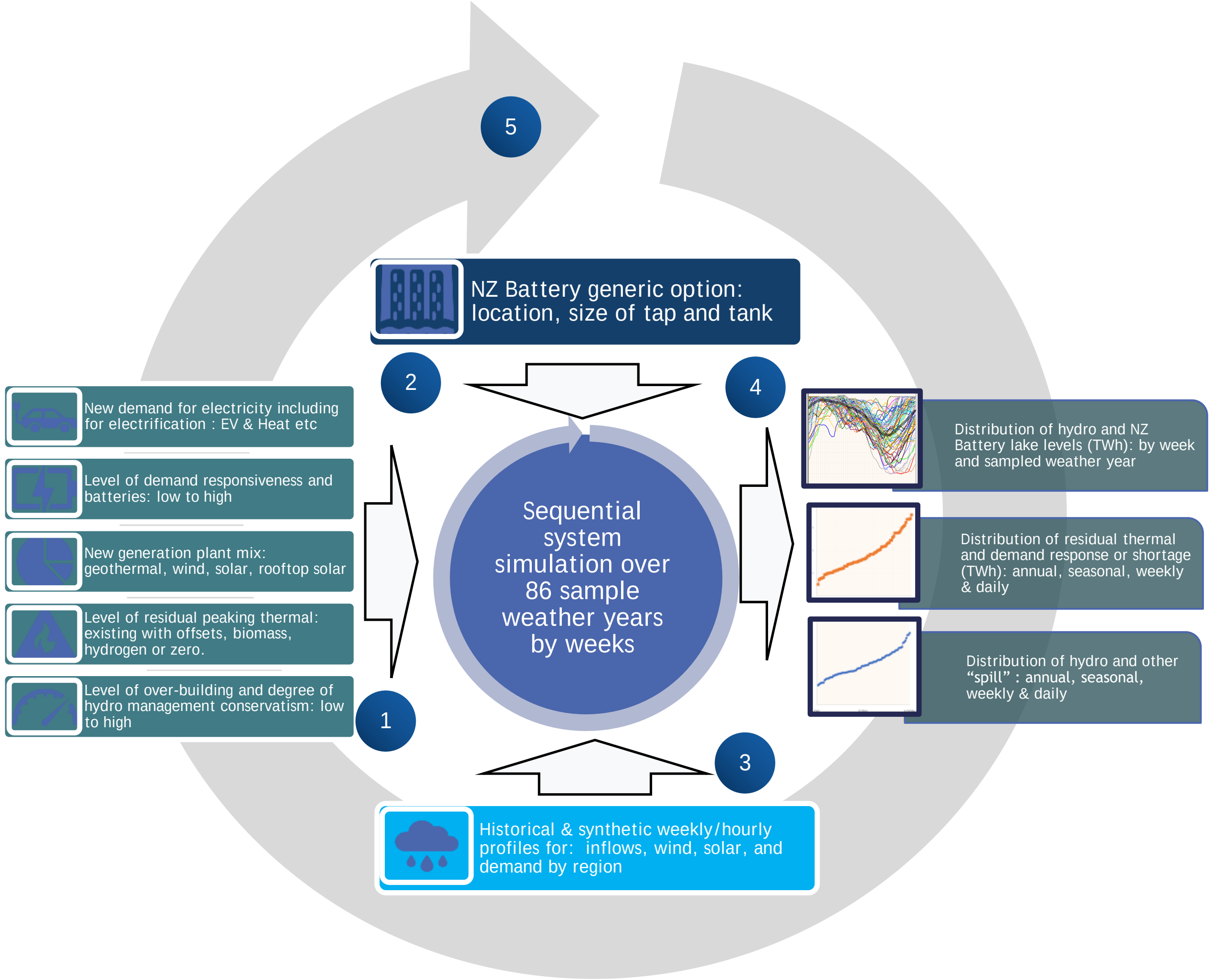
- The analysis needs to look well into the future because:
  - NZ Battery solution could be an asset with a long life (50+ years)
  - NZ's storage needs will change as the economy progressively electrifies to achieve net zero carbon

- To address these factors, we model three representative future years
  - 2035 - an early year in asset life. This year should be sufficiently far into the future to avoid transition issues (such as building and filling a large pumped storage facility) but soon enough to represent the initial benefits
  - "2050" - an intermediate year on the transition path in which electricity demand (ex Tiwai) is 50% higher than 2020
  - "2065" - a year in which electricity demand (ex Tiwai) is almost 100% higher than 2020 and represents a decarbonised economy
  - In all years we assume the Tiwai Aluminium smelter is closed

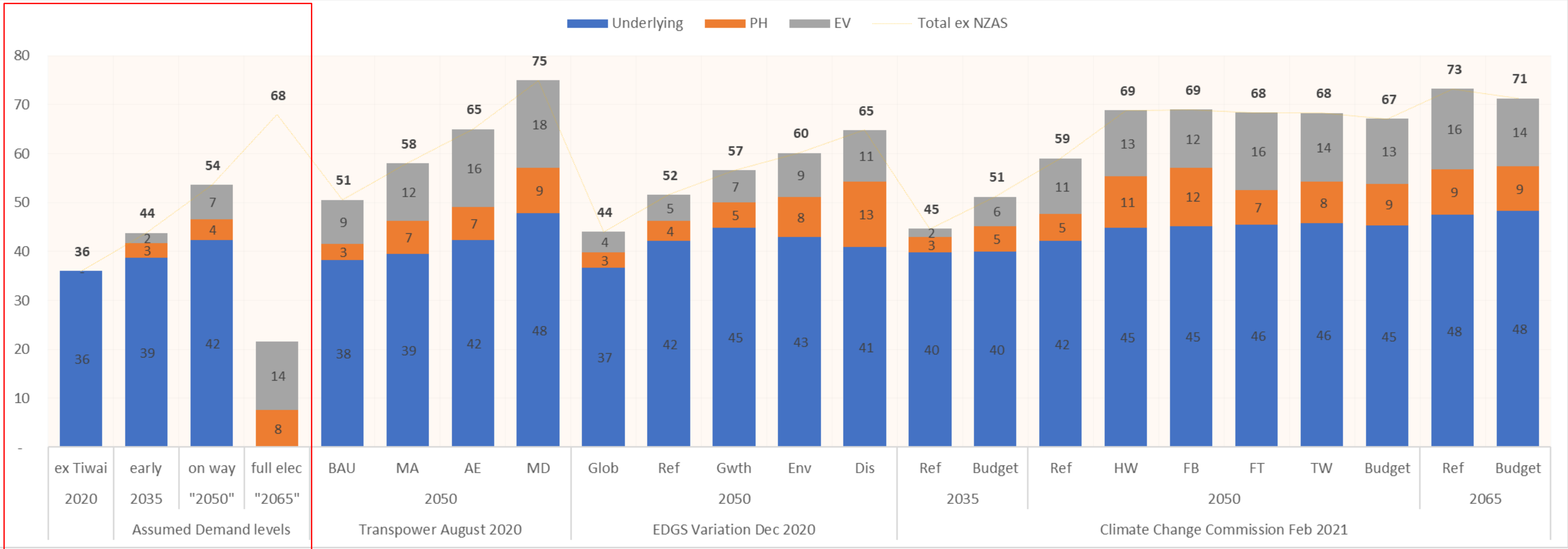
- Using these representative years, we can look far into the future but avoid the computational overhead associated with modelling every consecutive year (i.e. keep the modelling power to explore other matters)

High level modelling approach

- Step 1 - Set input assumptions for future demand growth, new generation options available to be developed etc.
- Step 2 - Set NZ Battery assumptions
- Step 3 - Apply the sources of variation - rainfall, wind, solar, demand etc
- Step 4 - Run model simulations to identify least cost mix of plant etc to maintain reliable supply for given set of input assumptions
- Step 5 - Iterate model to identify preferred target characteristics for NZ Battery under varying assumptions for future demand, etc



We assume energy demand growth of ~100% by 2065 - our assumptions are broadly comparable with recent reports from Transpower, MBIE & Climate Change Commission



Note: Above data for 2020 excludes Tiwai to show underlying trend

Base case assumptions:
- Tiwai closes by 2035
- Energy demand rises by 50% by 2050 and almost 100% by 2065, cf. 2020

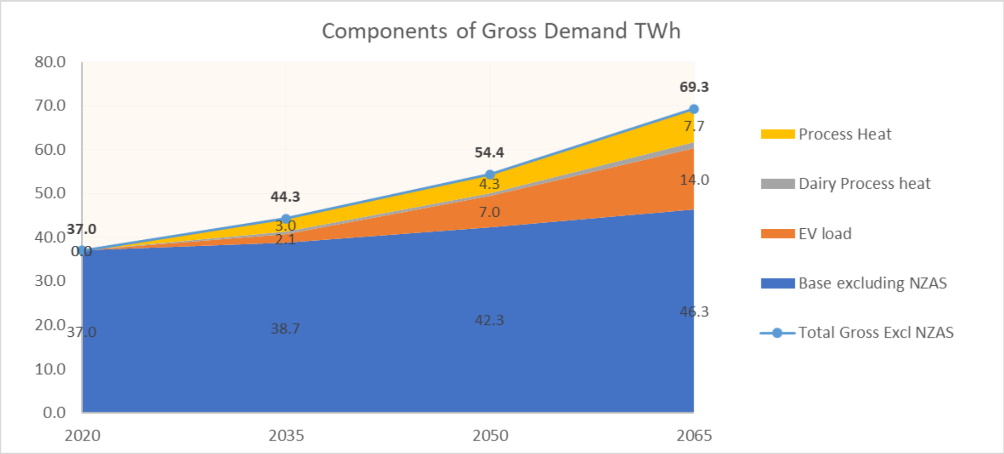
Our base case for 2050 is between Transpower's BAU and 'Measured Action' scenarios

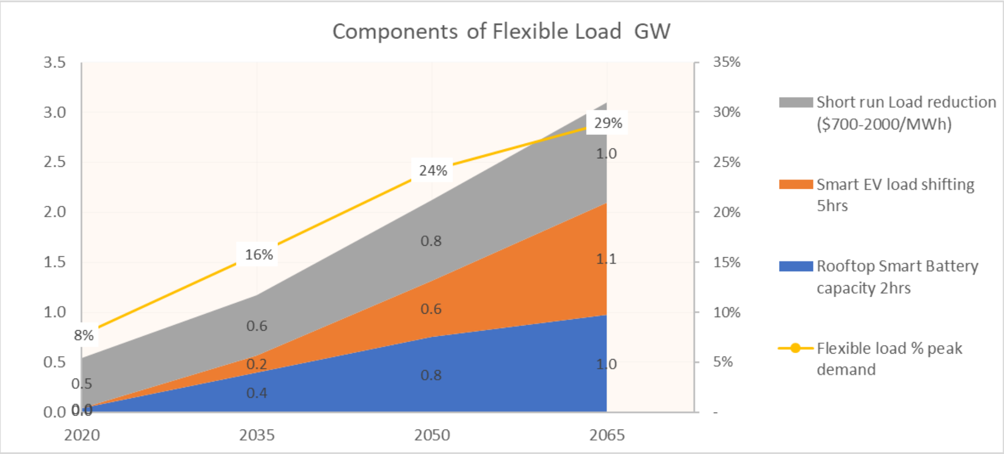
Our base case for 2050 is between MBIE's EDGS 'Reference' and 'Growth' scenarios

Our case case for 2035 is similar to CCC's Reference case
Our base case for 2050 is similar to CCC's BAU case
Our base case for 2065 is close to CCC's Budget case
In essence, CCC's projects an earlier rise in electricity demand, but reaches similar level to us by 2065

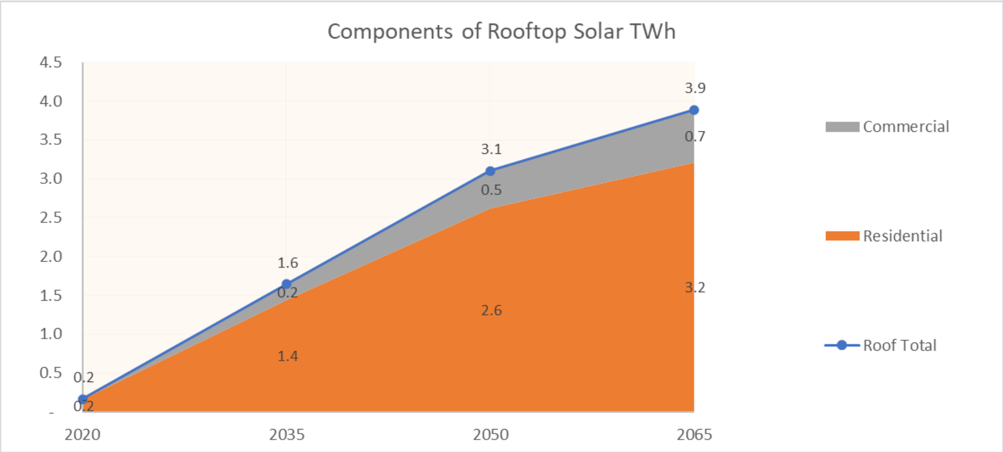
- As we discuss later, estimated benefit of NZ Battery generally grows as demand increases (and vice versa) but relationship is not linear and depends on generation supply mix

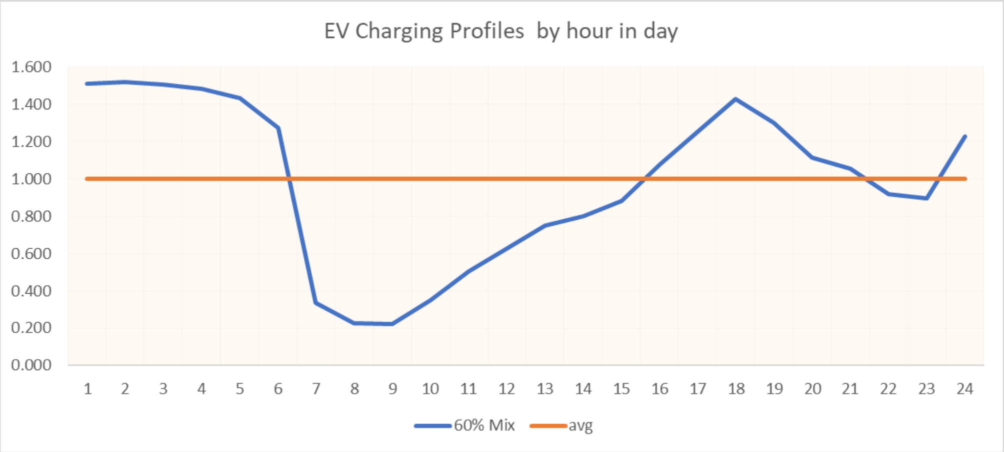
Our base case assumes that electric vehicles and process heat drive the growth in gross energy demand





Note the very significant increase in price responsive flexible demand from 8% to almost 30% of peak demand by 2065. This is mainly derived by smart scheduling of EV charging and behind the meter batteries associated with rooftop solar.





It is assumed that there is a mix of EV charging, 60% being charged overnight, and 40% charged as vehicles return to home base in the evening. On top of this base profile its assumed that is a very high level of additional smart price responsive load shifting.

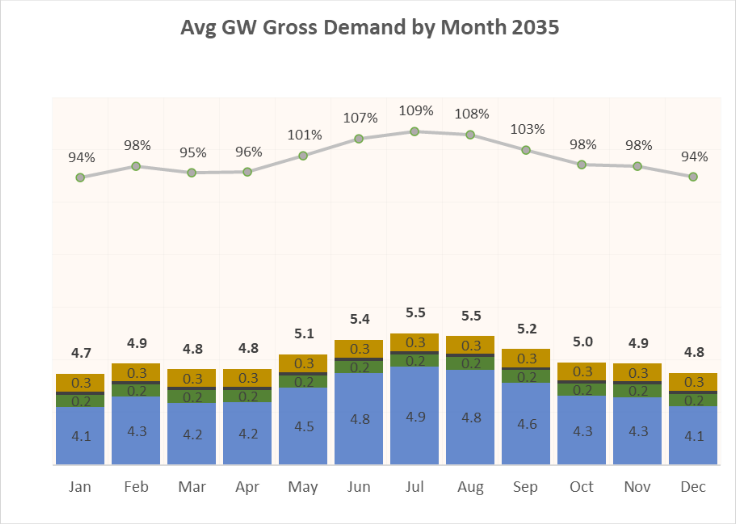
EVs and process heat drive the increase in gross electricity demand - other sources grow little over the period, in part because increases in efficiency offsets some of the underlying growth

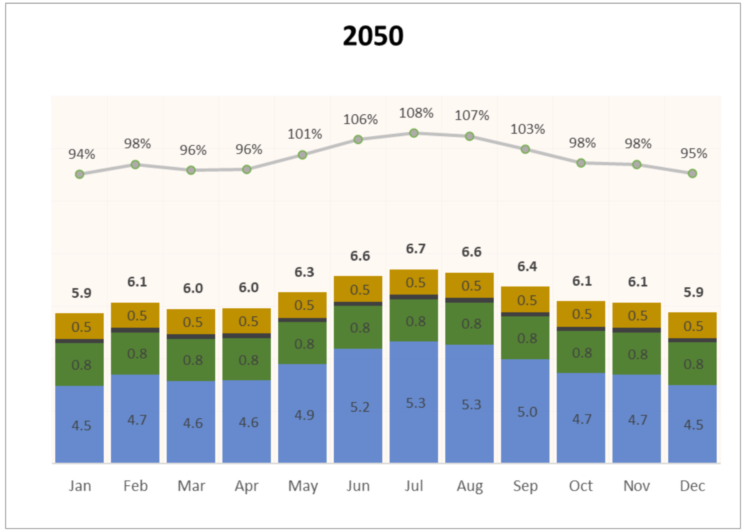
We assume EV demand is flat across the year but has some within day variation. Process heat demand is assumed to be flat across the day and the year.

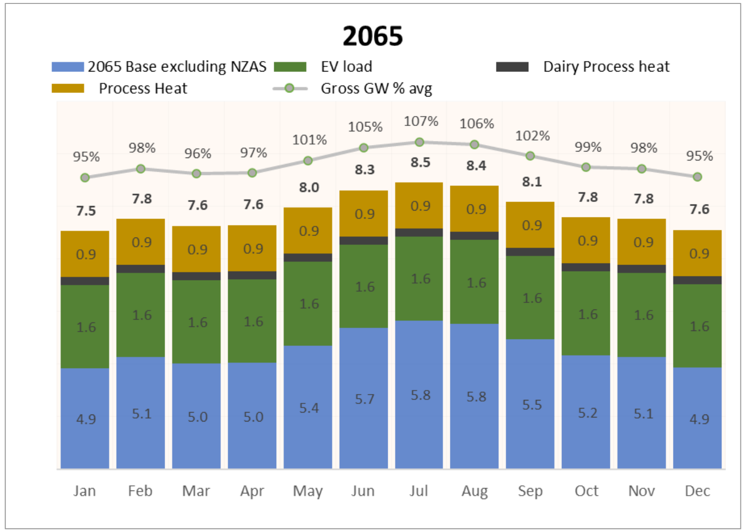
Note: Dairy process heat is assumed to be mostly met by biomass, so the bulk of process heat relates to low and medium temperature process heat electrification. Its assumed that winter seasonal shape of low/mid temperature demand is offset by the summer seasonal shape of dairy process heat. The EV profile is based on a 60% - 40% mix of optimised overnight charging and observed charging patterns as used by Transpower in their 2020 modelling. It is possible that there may be slight summer seasonal shape for EV demand, but this is not accounted for in the base modelling.

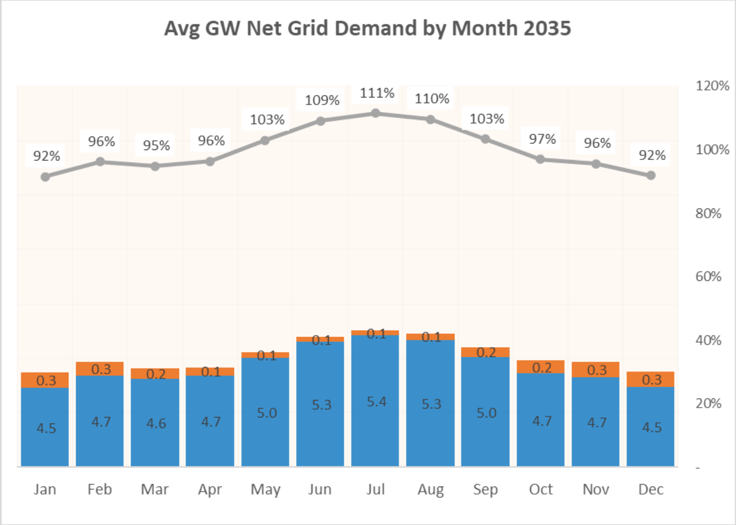
Seasonal shape of demand - expressed in terms of average GW per month

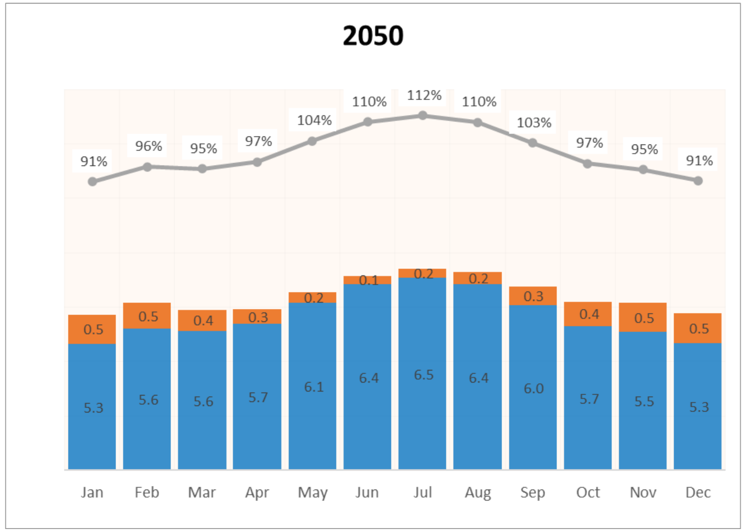
The gross seasonal demand shape is slowly flattening as the percentage of total demand relating to electric vehicles and process heat increases as a result of decarbonisation. However this seasonal flattening is offset by increases in rooftop solar.

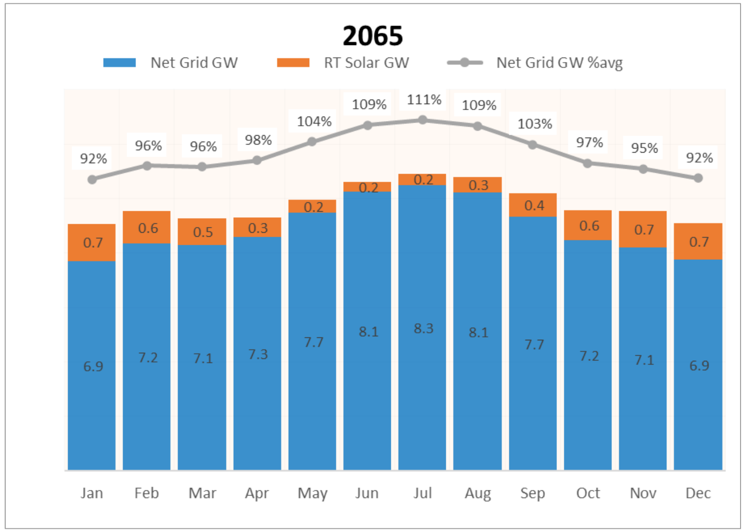












Note: The seasonal shape is a significant factor in determining the level of renewable overbuild required to meet peak demands in high demand / calm periods, particularly in the 100% renewable world.

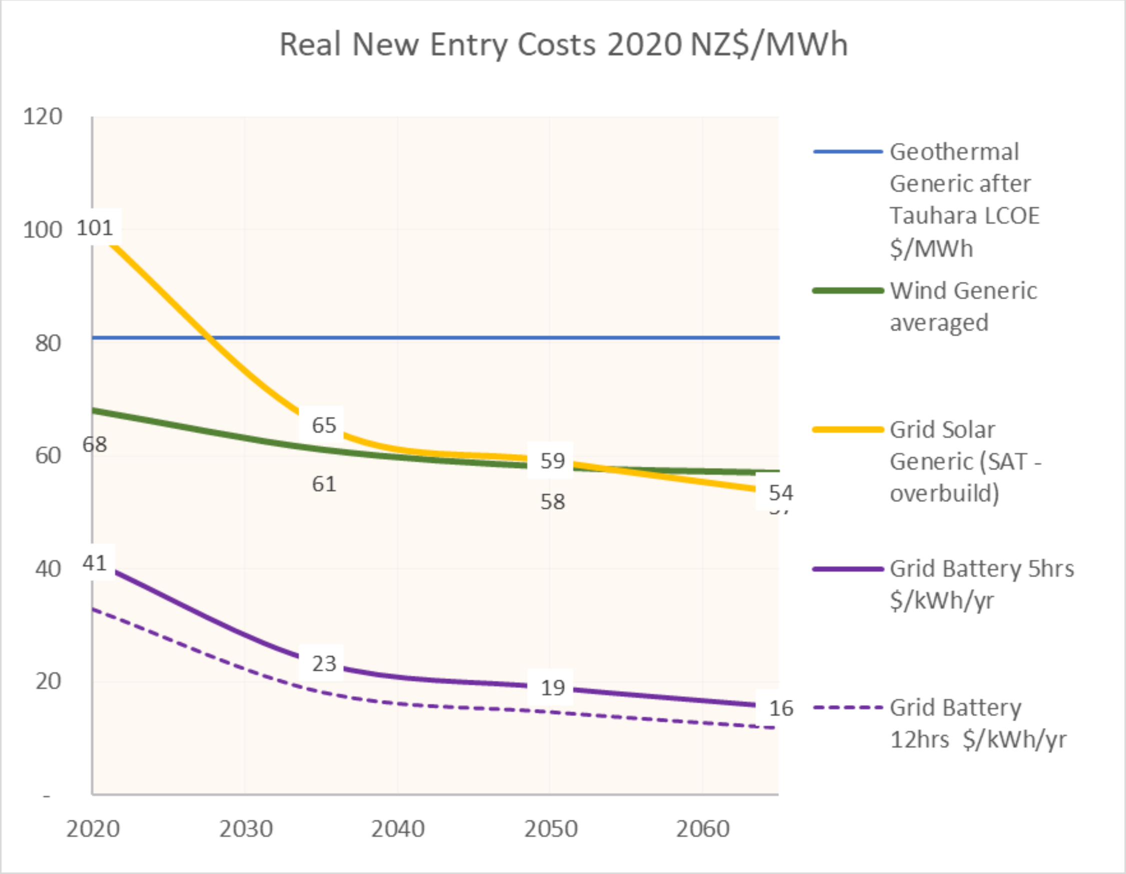
Transmission and new supply - key assumptions

- We model HVDC losses/constraints explicitly - HVDC capacity assumed to be 1400 MW (north) and 950 MW (south) and we assume no reserve-related transfer limits on basis that NI batteries should be able to support full reserves requirements
- Average HVAC losses are included in demand and AC grid is assumed to be unconstrained
- The model has a menu of new supply and demand response options available for development/use at different costs:
  1. New hydro - we assume no new hydro is available
  2. Geothermal - up to 1.3GW of new capacity is available
  3. Wind - unrestricted MW are available with downward sloping levelised cost of energy curve (-1.0% to 2035, then -0.5% pa)
  4. Grid connected solar - unrestricted MW available with downward sloping cost curve (-3.5% pa to 2035, then -0.9% pa)
  5. Rooftop solar - the volume of uptake is exogenous to model and rises to 4.0 TWh by 2065
  6. Batteries with rooftop solar provide the equivalent of 30% of average rooftop solar MW with 3hrs storage
  7. Unrestricted 5 and 12 hour grid battery systems are available to shift supply within days (provided they cover capex and opex)
  8. Smart EV charging for 70% of average EV MW load is available - this allows load to be shifted up to 5hrs
  9. Demand response is available in various tranches priced from $700/MWh
- As discussed later, we also consider a new zero-carbon thermal generation option in 2065 with fuel cost of $45/GJ (real $2021) - to reflect possible biofuel or hydrogen options.
  - Carbon prices in 2021 $ terms follow the CCC assumptions of $160/t, $250/t and $390/t in 2035, 2050 and 2065.

Variability in supply - key assumptions

- We have modelled variability in supply and demand as follows:
  1. Hydro
     - The model uses 86 years of synthetic weekly hydro inflow data derived from the historical period 1932 to 2017. These account for the major catchments in each island and a separation between tributary and controllable inflows. The data is based on the EA Opus data sets calibrated to historical actual generation levels. Run of river hydro are based on actual generation back to 2000 and Opus series prior to that. To deal with multi-year storage limitations the model runs through a full set of inflows year by year with the starting storage being set from the simulated end storage the year before. This ensures that there is a range of starting storage positions, but the starting and ending storages averaged over all runs are virtually the same so there is no need to adjust averaged results for changes in average storage (see slide 60).
  2. Wind
     - The model uses 18 years of synthetic hourly wind data (2000 to 2017). This is based on actual data where possible for existing wind farms and profiles derived from the renewable ninja web site (satellite data based) for representative regional sites. These 18 years (for wind, solar and demand) are repeated for hydro years prior to 2000.
  3. Solar
     - The model uses 18 years of synthetic hourly solar data (2000 to 2017). This is based on profiles derived from the renewable ninja web site (satellite data based) for representative regional sites. These 18 years are repeated for hydro years prior to 2000. Separate profiles are provided for rooftop and grid connected solar (the latter is assumed to have single axis tracking).
  4. Demand
     - The model uses 18 years of hourly demand profile data (2000 to 2017) and seasonal profiles which reflect the average over the last 10 years. Historical demand variations are included in the modelling along with wind and solar supply variation.

We assume wind and solar costs decline over time in real terms - but our projections are much less aggressive than some other forecasts



- Costs for solar and wind have been declining and further falls are expected
- Our estimates reflect recent projects and market information from NZ and Australia (including AEMO planning assumptions for Australia translated to NZ conditions).
- Some other forecasts have much more aggressive reductions - for example a 2021 Transpower report included projections of $39/MWh and $37/MWh for wind and solar in 2035, and $30/MWh and $27/MWh in 2050*
- As we discuss later, estimated benefits of NZ Battery decline if new generation costs are lower than assumed (and vice versa)

* Source: Transpower, Whakamana i Te Mauri Hiko - A Roadmap for Electrification - Decarbonising transport and process heat, February 2021, Fig 28. Figures are for non-firm energy, and are assumed to be real 2021 dollars.

Note: These costs assume a 7% post tax nominal weighted average cost of capital. They account for tax depreciation and 2% pa inflation. Construction periods are 1 year for wind, solar and batteries and 3 years for geothermal. Economic lives are assumed to be 17 yrs for battery systems, 27 yrs for wind and solar and 30 yrs for geothermal. Potential generic capacity factors are assumed to be 41% for wind and 21% for grid solar (with single axis tracking and overbuilding). Solar costs assume 0.5% pa panel degradation.

Modelling of new investment in generation and small scale batteries

Approach

- In essence, for a given level of future demand and assumed existing supply the model calculates the "revenue[1]" available from incremental investments in different new supply resources (wind, geothermal, LiON batteries etc)
- These revenue sums are compared to the annualised costs of the different options (noting costs decline over time)
- When revenue for a resource type exceeds its cost, we add more of a resource
- An iterative process of adding resource is followed until the point where further investment is no longer revenue adequate
- As discussed later, we have cross checked these planting results with a 'central planner' rule of minimising total costs – and the results are functionally equivalent – giving us confidence that the approach is robust

North/South

- The model tends to build new generation/small batteries mainly in the North Island – especially in the earlier years. This reflects the effect of HVDC capacity constraints, Tiwai shutdown, thermal plant closures, preponderance of demand

Regional wind/solar

- The model places wind/solar investments in different locations to reflect effect of correlation issues GWAP/TWAP[2] factors (see later slide for more info)

1. The "revenue" measure is derived from prices which depend on assumed water value curves, the SRMC of plant, and demand response and shortage cost tranches.
2. Generation weighted average price / time weighted average price. This provides a measure of how much of the average market price that a particular project can 'capture'.

NZ Battery - options and assumptions

South Island options		
Storage (tank)	Max output (tap)	Label used in tables
7 TWh	1 GW	Bat S_7.0_1.0_Shr
5 TWh	1 GW	Bat S_5.0_1.0_Shr
3 TWh	1 GW	Bat S_3.0_1.0_Shr
3 TWh	0.8 GW	Bat S_3.0_0.8_Shr
3 TWh	0.5 GW	Bat S_3.0_0.5_Shr

+

North Island options		
Storage (tank)	Max output (tap)	Label used in tables
1 TWh	0.8 GW	Bat N_1.0_0.8_Shr
0.3 TWh	0.8 GW	Bat N_0.3_0.8_Shr

Combined options
Bat NZ_4.0_1.6_Shr

- Storage capacity (tank) options were selected to reflect plausible possible schemes based on current (albeit limited) information - in each case max output (tap) was sized to match storage capacity and/or market need
- In all cases we assume 75% round trip efficiency (i.e. 25% of energy input is used for pumping)
- NZ Battery pumped storage is assumed to operate in similar fashion to other major reservoirs - this is achieved by a “shared” water value approach similar to that used by Energy Link
- We also tested an alternative approach based on a set of winter and summer guidelines to drive pumped storage to fill during the periods of higher ‘spill’ risk and then run down as required during the winter
- As we discuss later (see slide 62), both approaches yield similar estimates for gross economic benefits (even though sharing of ‘duty’ between NZ Battery and reservoirs is different)

Scenario 'worlds'

- We estimate the benefits of NZ Battery options in three alternative 'worlds':

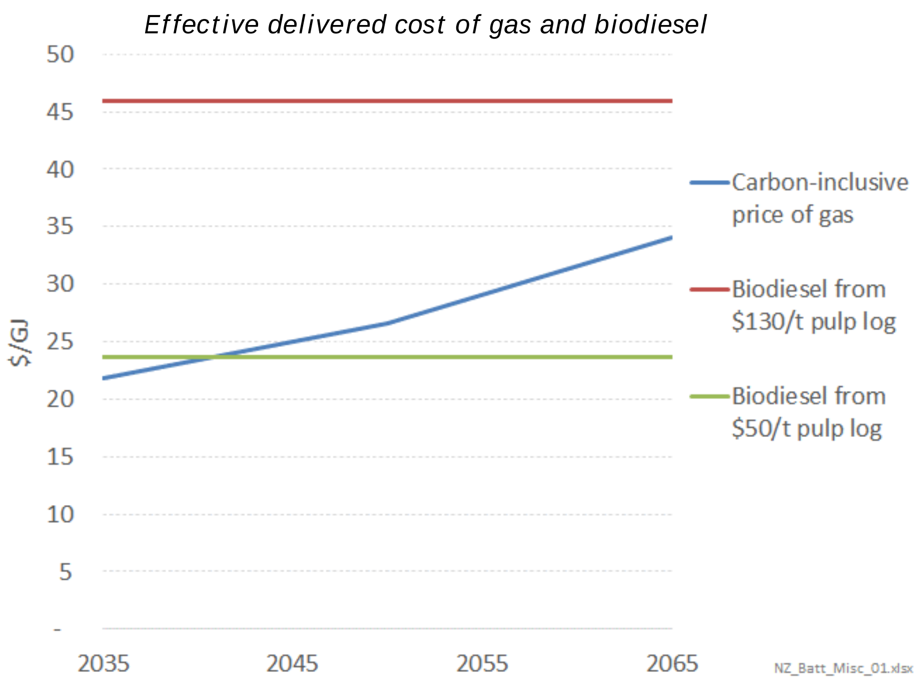
1. 100% renewables and no peakers - this world assumes all thermal stations (including cogen and peakers) are retired by 2035. This world is consistent with the Government target of achieving 100% renewable electricity by 2030, and it is used as the primary point of reference.

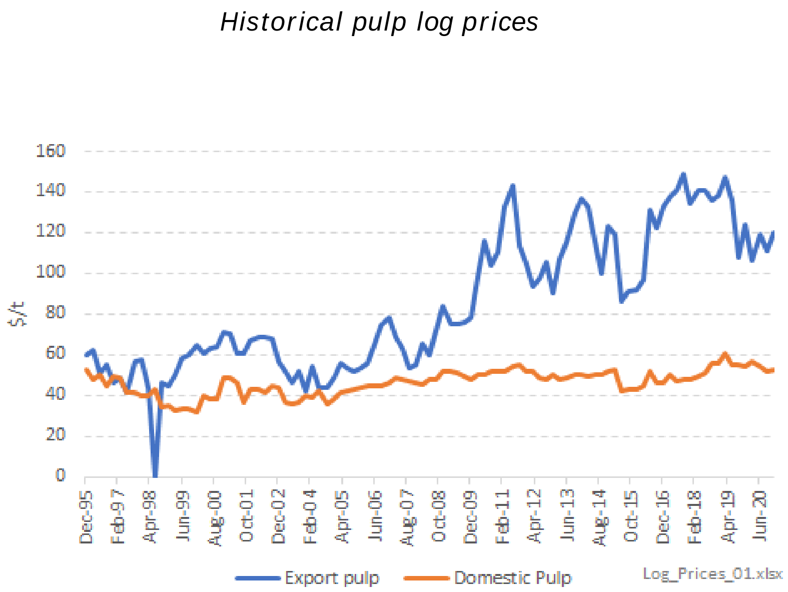
2. Limited thermal world - this case assumes all baseload thermal and cogen stations are retired by 2035, but gas-fired peakers remain and pay the rising carbon charges ($160/t, $250/t and $390/t in 2035, 2050 and 2065) and gas prices if they operate. This results in around 2% of electricity being generated by peakers on average. This world is not consistent with the Government target of 100% renewable electricity by 2030. However, it provides an additional reference point to check results which is useful given the very long forecast horizon being used in the analysis.

3. 100% renewables and green peakers - this world is the same as (1) above except that it assumes zero carbon fuel is available at $45/GJ (real $2021) by 2065. As we discuss in the next slide, this appears quite plausible. This world is also consistent with the Government target of achieving 100% renewable electricity by 2030.

What are 'green' peakers?

- Green peakers are combustion turbines which use a zero carbon fuel - such as biodiesel or green hydrogen
- The capital cost for such turbines is well understood but there is some uncertainty over the fuel cost. Having said that, research by Scion[1] indicates biodiesel from pulp logs using an *existing technology* would cost roughly $25t-$45/GJ to produce depending on log costs
- Furthermore, the government's recent in principle decision to mandate biofuels[2] for transport makes it likely biofuels will be available at scale by 2050 (or before)
- Given these factors, we consider it reasonable to assume that a green peaker fuel will be available at $45/GJ ($2021) in 2065





1. Scion, February 2018 report: *"New Zealand Biofuels Roadmap Technical Report"*, and MfE's "*Marginal abatement cost curves analysis for New Zealand*"
2. See https://www.transport.govt.nz/area-of-interest/environment-and-climate-change/biofuels/

Gross benefit estimates for different NZ Battery options

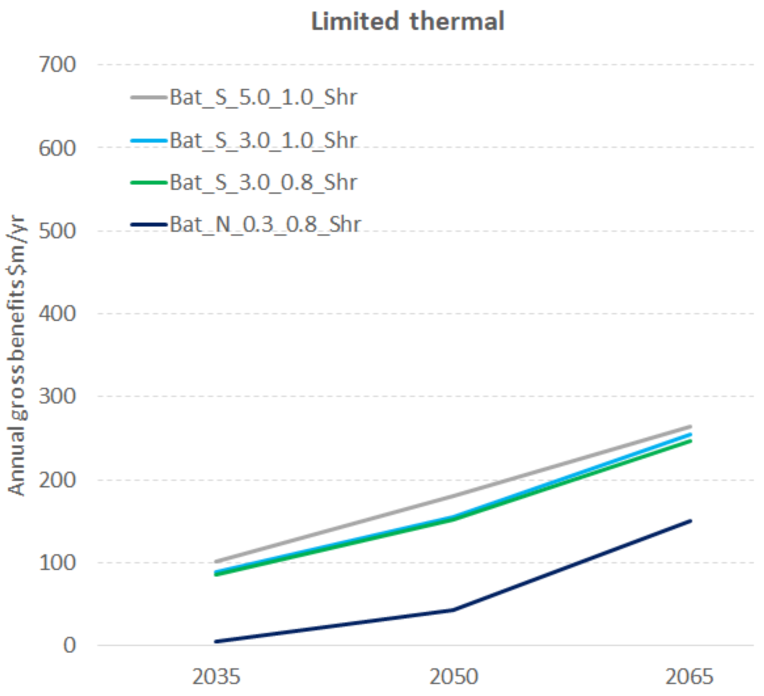
This section sets out the estimated gross benefits for various NZ Battery options

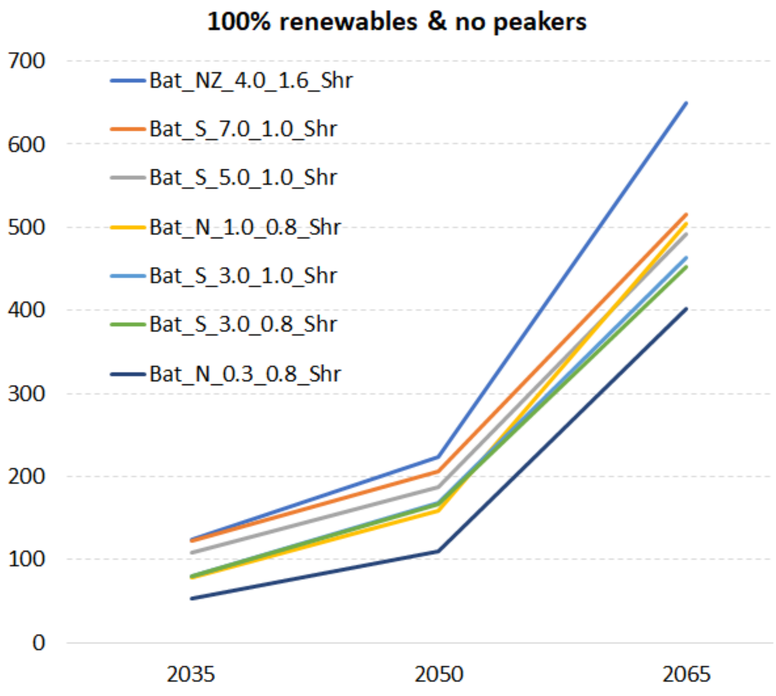
- This section sets out gross benefit estimates for various NZ Battery options

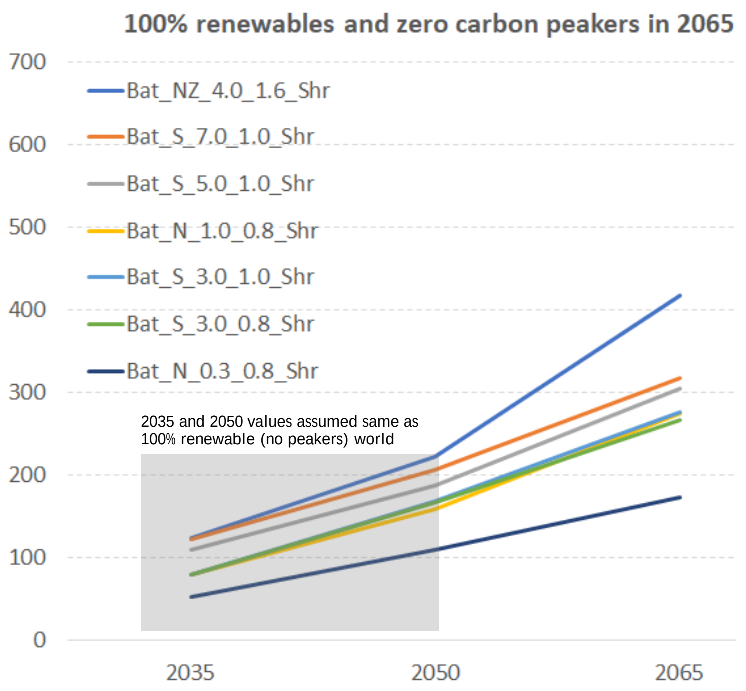
- In particular it presents analysis on:
  - How gross benefits vary with different storage capacities (‘tank sizes’)
  - How gross benefits vary with different maximum output levels (‘tap sizes’)
  - How gross benefits vary with location of a NZ Battery in the North Island or South Island, or both islands

Gross benefits from NZ Battery increase over time as system growth increases the need for firming of seasonal/intermittent generation sources

Limited thermal world assumes all baseload thermal retires by 2035 and only peakers remain - with fuel/carbon rising from $14/GJ to $35/GJ	100% renewables world assumes all thermal is retired by 2035 including peakers	100% renewables + green peakers world is same as 100% renewables world, except it assumes by 2065 there are zero carbon fuels at $45/GJ and it includes peaker capex





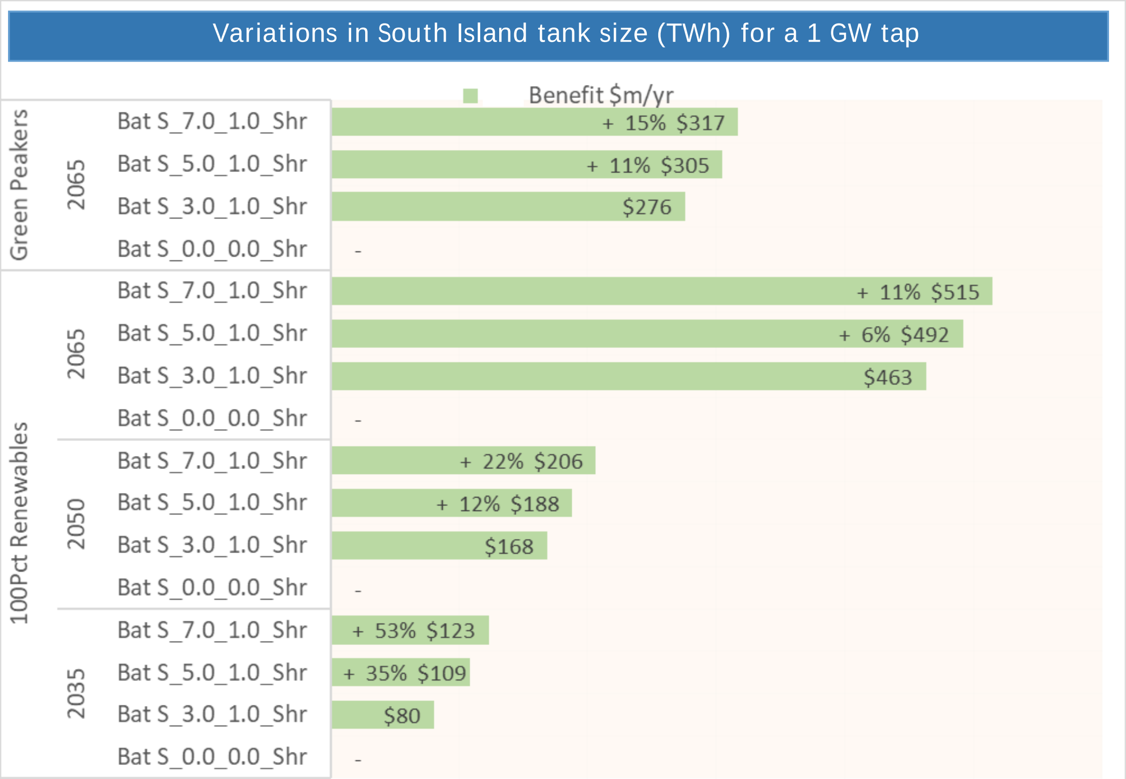


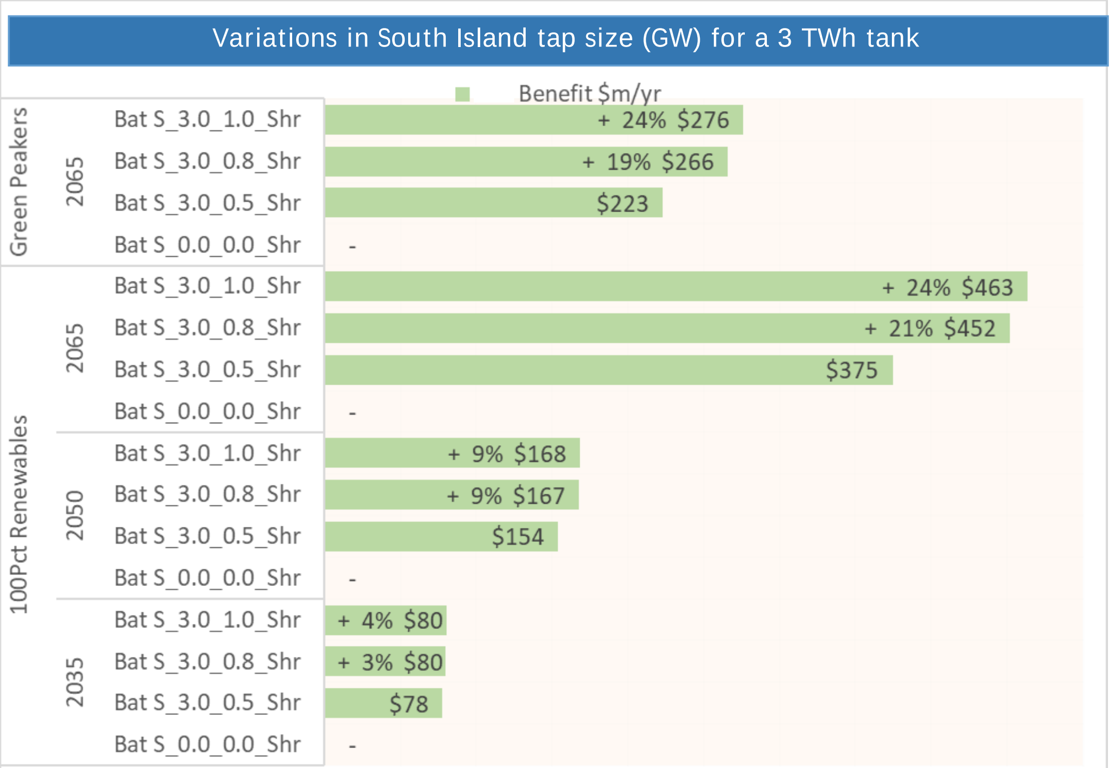
Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

Gross benefits from NZ Battery increase over time - but are constrained by availability of peakers in 'Limited Thermal' world as they also provide flexibility services. Effect is particularly noticeable for NZ Battery option in North Island	NZ Battery provides more benefits in '100% renewables world' - although difference is modest in 2035 and 2050. By 2065 NZ Battery provides significantly more benefit - reflecting projected growth in intermittent renewables and consequent greater need for other flexible supply	Much of the benefit of NZ Battery in 2065 rests on assumption that no other large-scale zero carbon flexibility options will exist. As discussed earlier, this is highly questionable. If zero carbon peakers were available (at $45/GJ) that would significantly reduce benefits of NZ Battery

In the next slides we explore the effect of different tank and tap sizes on gross benefits. Estimates are reported for each reference year in 100% renewables (no peaker) world. We also include estimates for the 100% + green peaker world for 2065.

Gross benefit for alternative South Island “tank and tap sizes”





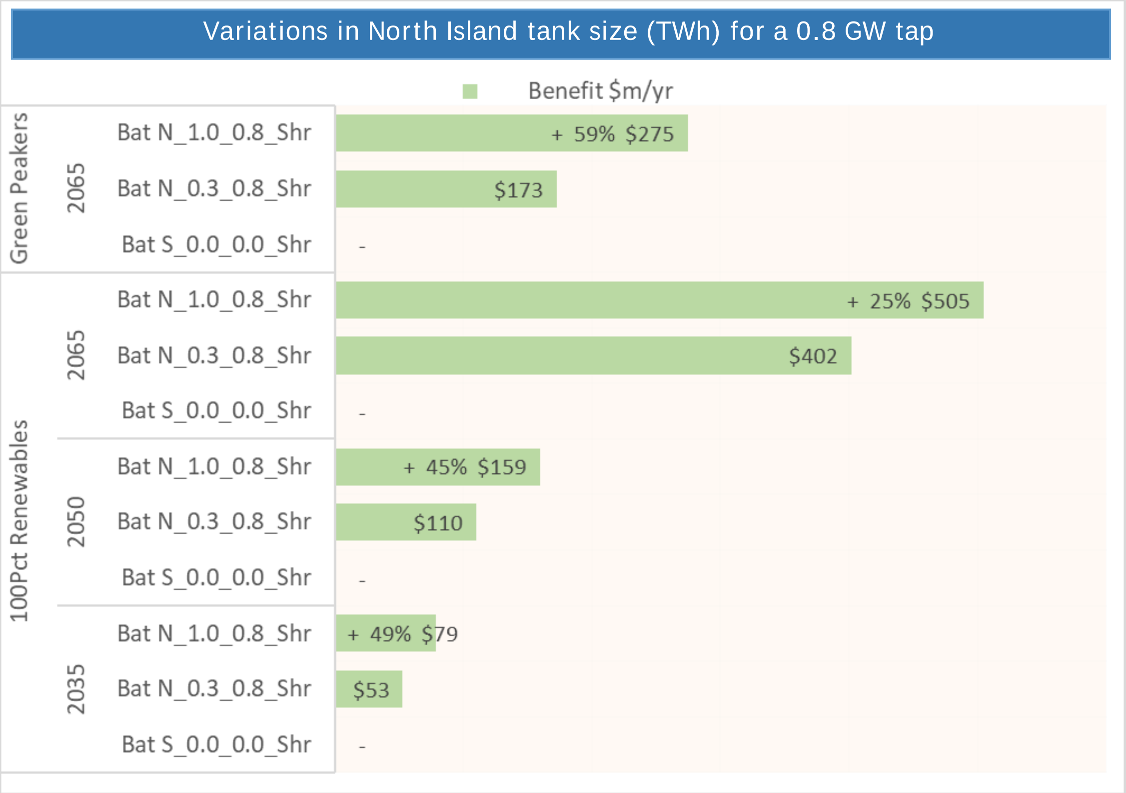
Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

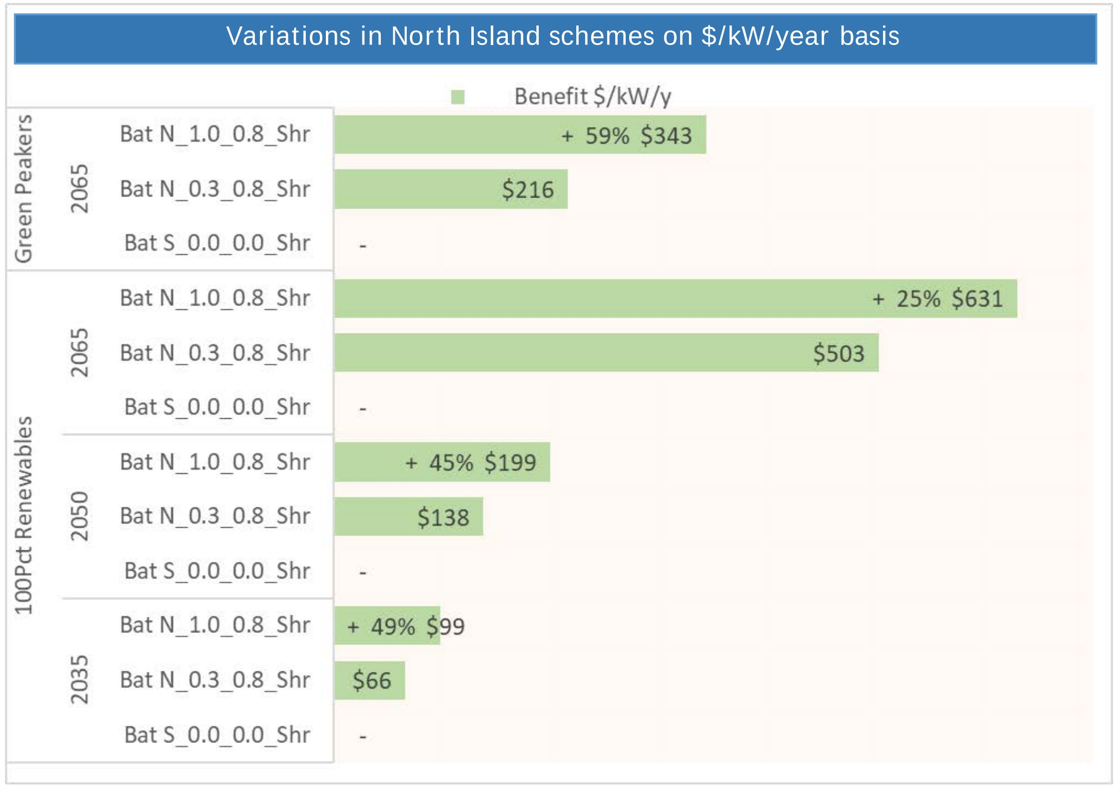
Gross benefits in ‘steady state’ (2065) are not particularly sensitive to size of tank. Lifting tank size by 60% from 3TWh to 5TWh raises benefit by only 6-11%. Lifting to 7TWh (+130% cf. 3TWh) raises benefit by only 11-15%.

Analysis suggests that unless storage increments are very cheap, a 3TWh storage capacity may be preferable for a SI option. In the absence of further information about storage costs, we focus on a 3TWh storage capacity as the central case for a SI Battery option…

Turning to the question of tap size, we have modelled a range of alternatives assuming a 3TWh tank. Analysis shows modest incremental benefits (+24%) if 0.5GW tap is increased by 100% to 1.0GW. This reflects S->N transfer limits on HVDC (and HVAC) which bind when there is scarcity in the NI and also N->S constraints when there is NI “spill” in the summer during low demand/high wind/solar. Incremental benefits of moving from 0.8GW to 1.0GW (25% tap increase) are particularly low (5%).

Gross benefit for alternative North Island "tank sizes"





Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

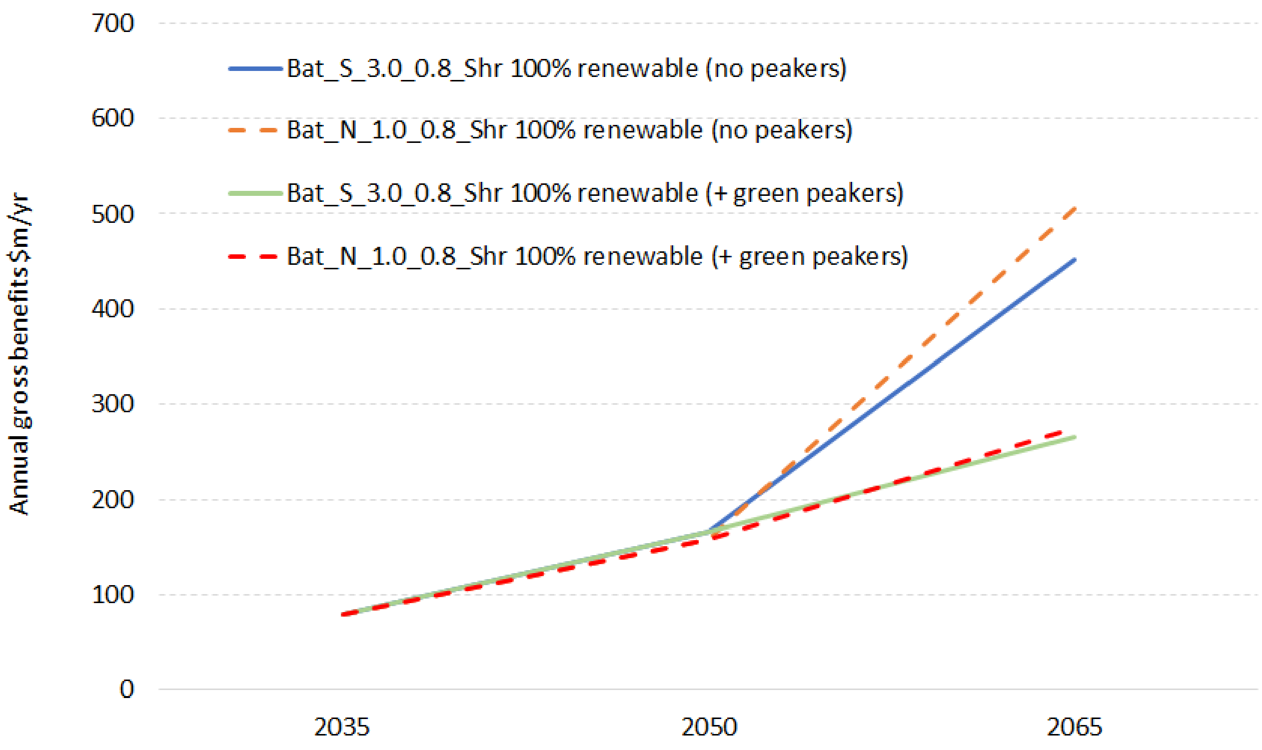
We model tanks of 0.3 TWh and 1 TWh in the NI, assuming storage options are more constrained by physics in this island (we have no reliable info at this stage). As a point of comparison, the Lake Taupo has around 0.6 TWh of storage from a 1.4m range). Scale appears to have more effect on benefits in the NI, which increase by 25-59% in moving from 0.3 TWh to 1 TWh. As with SI options, it is not possible to determine if this is sufficient to justify the incremental cost of increasing storage, until some specific options are found and investigated.

This chart expresses benefits in $/kW/yr. Excluding the potentially overstated 2065 values in the 100% renewable world, the value of even the smaller storage option is reasonable at $216/kW/yr. There may be NI options of this size available that would be economic at these levels assuming the NI has options at costs similar to those seen overseas.

A 0.8GW Battery in the North Island would provide similar gross benefits to a 0.8GW Battery in the South Island which had three times the storage capacity

- Analysis indicates a 0.8GW 1TWh Battery in the North Island provides similar benefits to a 0.8GW 3TWh Battery in the South Island - despite the latter having 3x the storage capacity
- Furthermore, the benefits for the two options are very similar across years and for the two 'worlds' in 2065
- This reflects a range of factors including:
  - Supply growth is driven by rising demand in the North Island where most people live - and especially the need to meet peak (MW) demand during calm/cold/dry periods rather than dry years (see later info on changing need for flexibility)
  - Growth in peak demand places emphasis on the size of the 'tap' rather than the 'tank'
  - Benefits from South Island taps are constrained in the inter-island grid limits (especially HVDC) which reduce ability to send energy north when needed, and capture and store surplus energy at other times. Round-trip grid losses also cut into benefits when constraints don't apply. Likewise, enlarging a South Island tank provides limited benefits
  - NI Battery options are less affected by grid constraints and losses. Furthermore, the presence of abundant supply sources with short-term intermittency (solar/wind) means that even small increments of storage capacity are quite beneficial

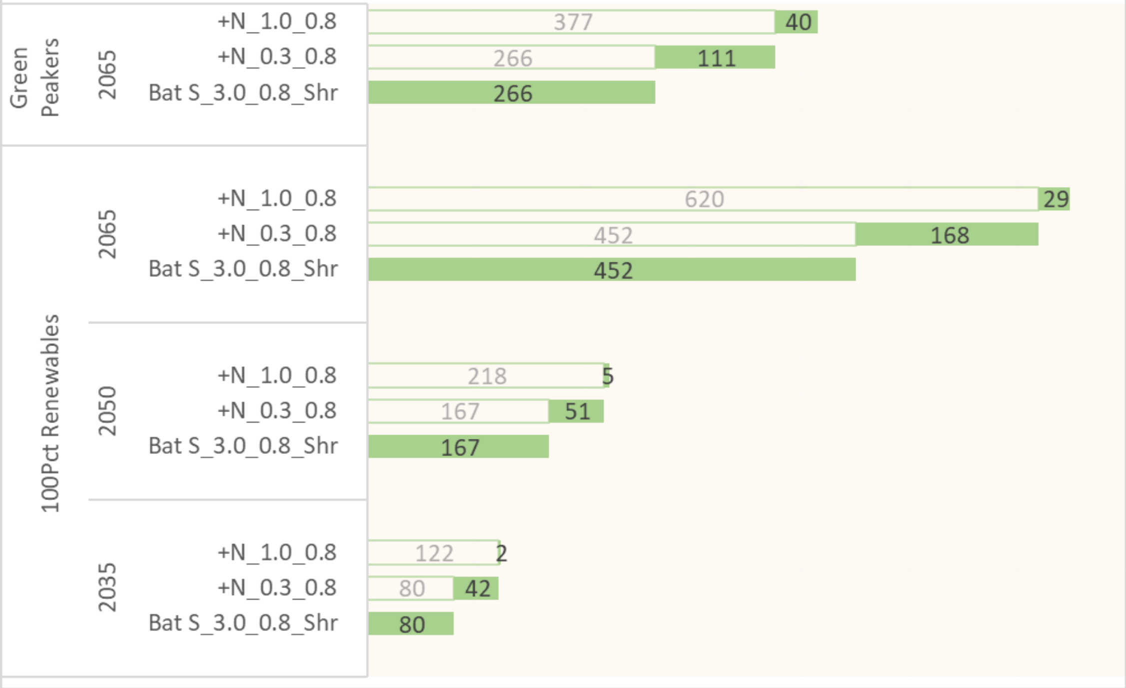
Gross benefits of SI and NI options



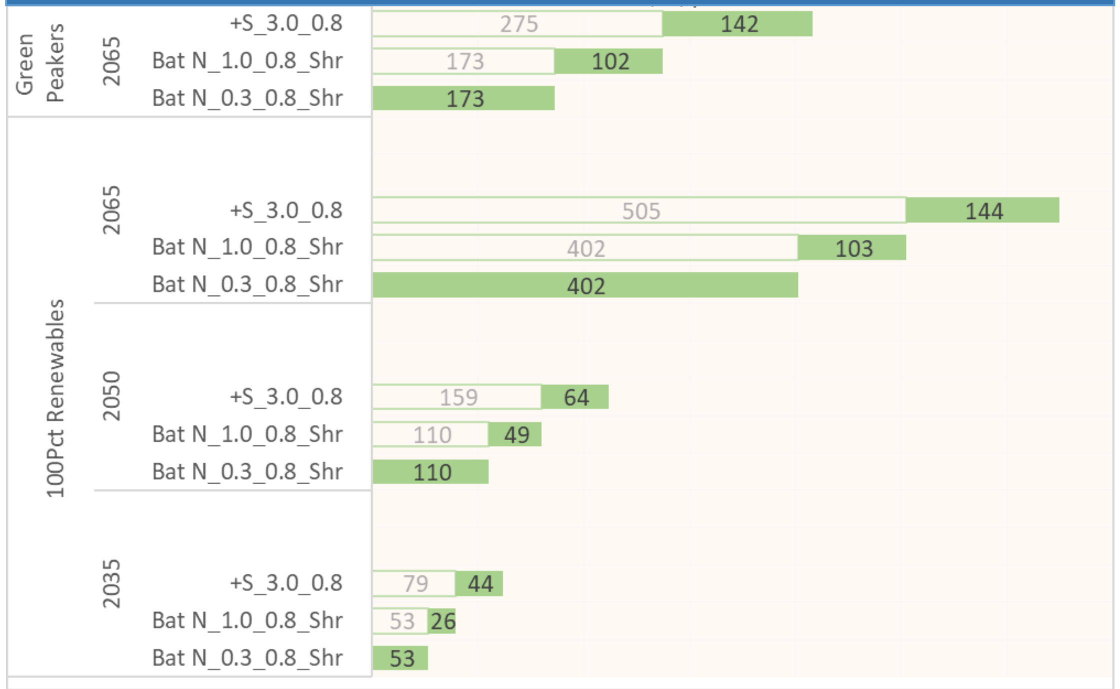
Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

We have also considered an option where NZ Battery storage is developed in both islands

Assume SI has 3TWh/0.8GW scheme and consider incremental benefits of NI option with 1TWh/0.8GW



Assume NI has 1TWh/0.8GW scheme and consider incremental benefits of SI option with 3TWh/0.8GW

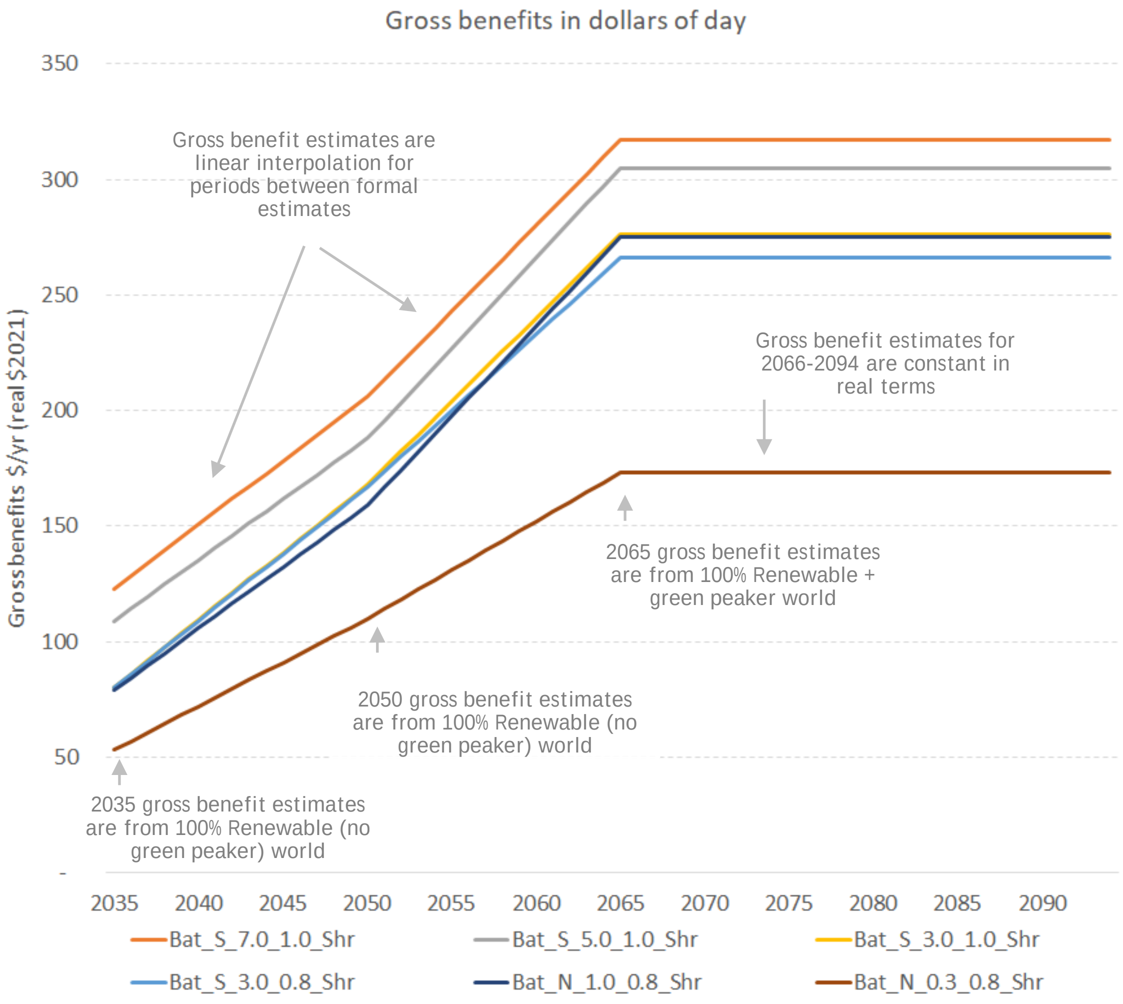


Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

- Total benefit from combined schemes in 2065 is $649m/yr (in 100% renewables world) and $417m/yr (in 100% renewables + green peakers world)
- If schemes were to be developed sequentially, timing decisions should be based on *net benefits* of each increment

To compare different options, we compute levelised gross benefit for each project assuming a 60 year life in a composite world of 100% renewable + green peakers

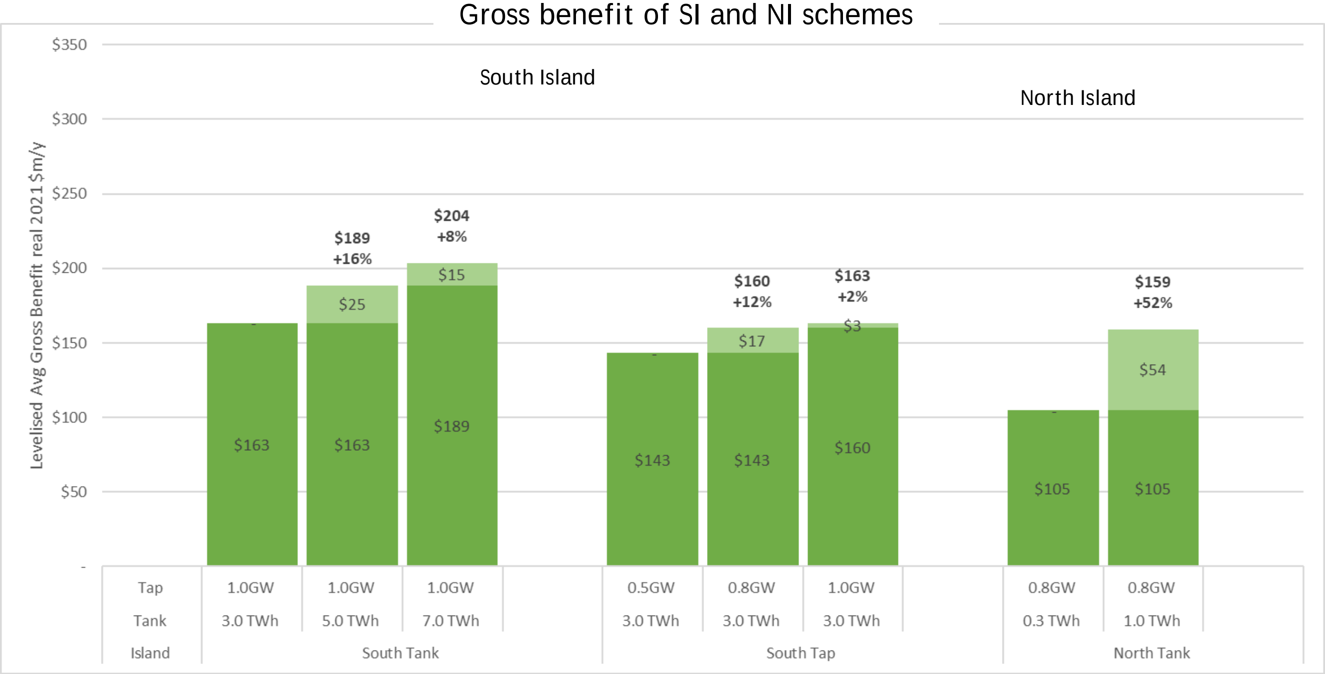
- We have computed the levelised gross benefit for each project
- For 2030 and 2050 'years' we use gross benefit estimates for the 100% Renewable (no peaker) world
- For 2065 we use gross benefit estimates for the 100% Renewable + green peakers world
- We consider these assumptions to be robust given information on likely cost of biofuels (see earlier slide) and ability to add other renewables and green peakers as needed for 2065 and beyond (if not before)
- Gross benefits for intermediate years are estimated based on linear interpolation
- We assume constant real benefits post-2065 and a 60 year economic life span - while some physical components may last longer (e.g. dams) it is likely that electrical and mechanical equipment will need to be replaced within that timeframe. Demand growth beyond the 2065 level (with full electrification of transport) should be relatively low given likely improvements in efficiency of electricity use, and this can be met through a combination new renewables and green peakers, within day batteries and demand response. Thus 2065 should represent a reasonable approximation of the long term equilibrium.
- For each project we compute the levelised value of gross benefits (i.e. the constant value per year that yields the same present value as the 'shaped' trajectories, based on a 6% real pre-tax discount rate)

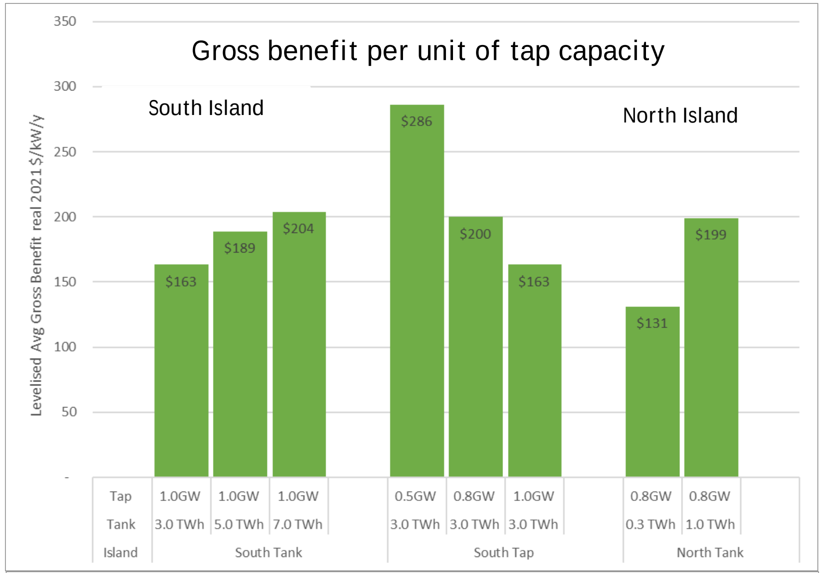


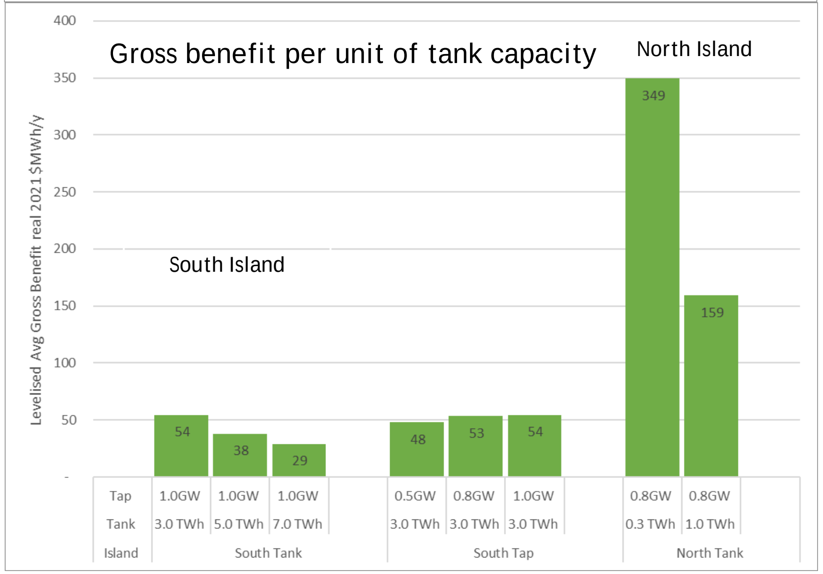
Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

Gross benefits for South Island options do not vary greatly with tap or tank size above a combination 3 TWh/0.8GW. NI storage capacity appears beneficial if feasible

- Gross benefits for SI options are not strongly correlated with tank or tap sizes (increasing tank +133% → +24% benefit, increasing tap +25% → +2% benefit)
- Gross benefits for NI options are more strongly correlated with tank size (increasing tank +233% → +52% benefit)
- A 1 TWh 0.8GW NI scheme provides similar gross benefits to SI schemes with more storage
- A small NI scheme (0.3 GW storage) provides significant gross benefits when measured in $/tank size or $/tap size



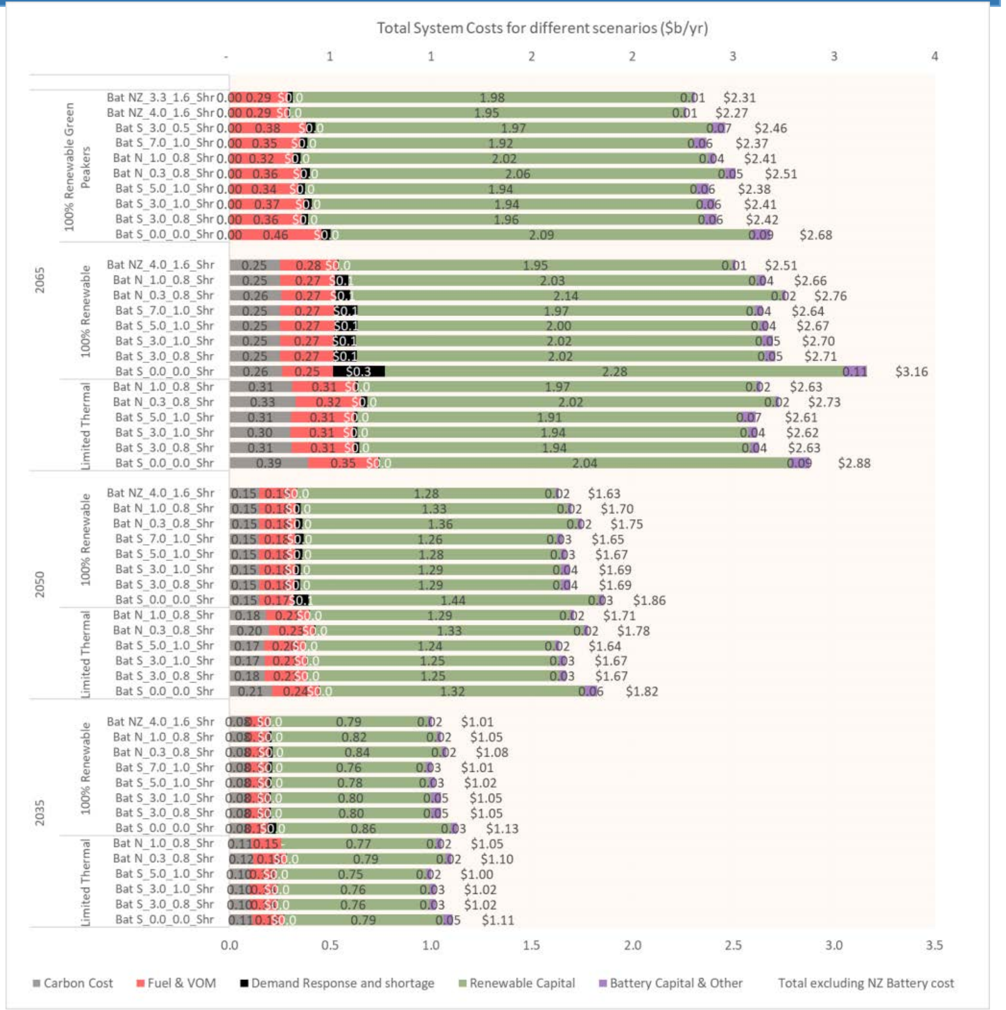




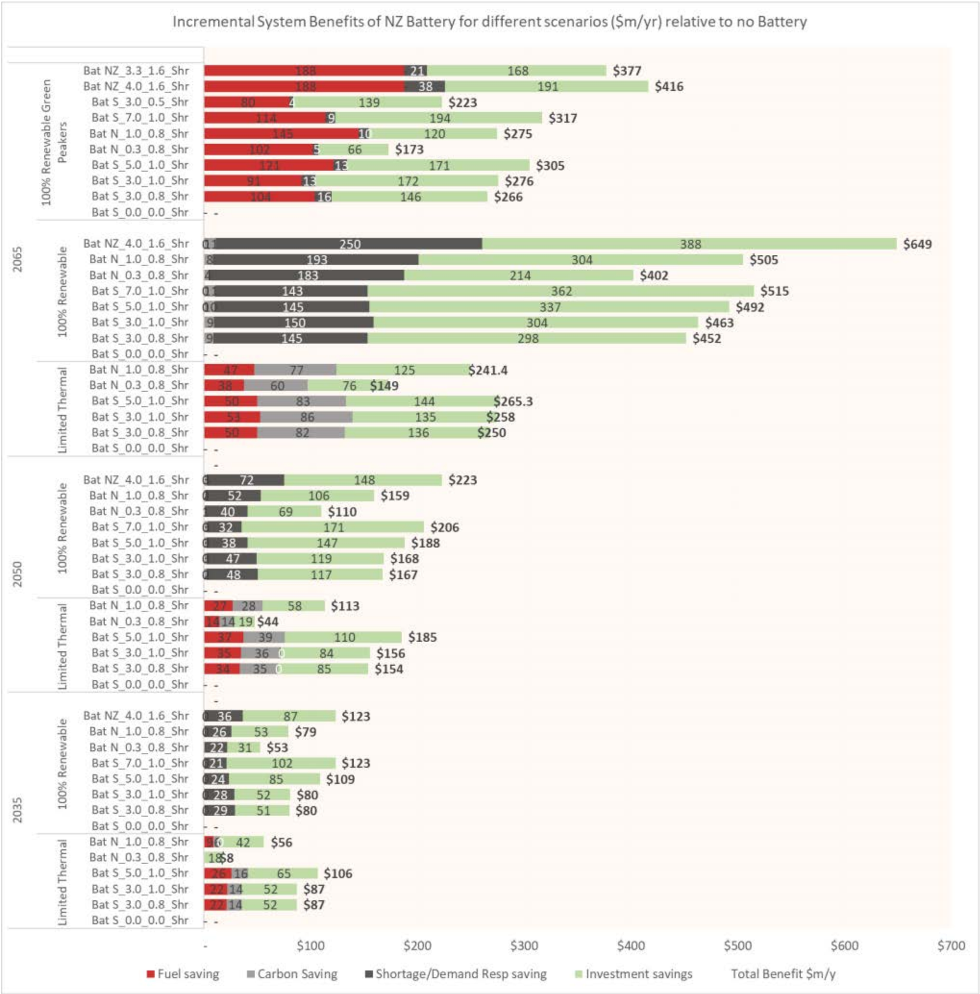
Notes: Gross benefit figures are in real terms and dollars of day received from 2035 (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

Total system costs and incremental system benefits for various Battery options

Total Benefits including estimated annualised cost of NZ Pumped Hydro Storage Options



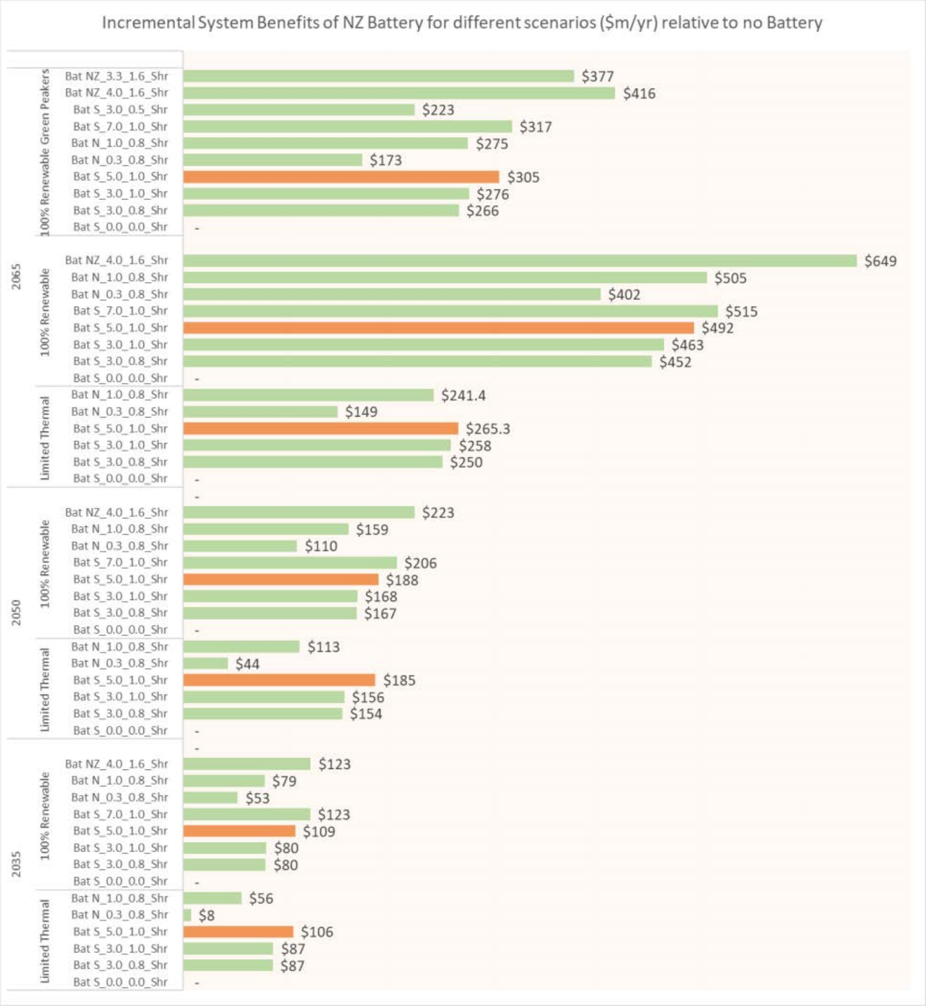
Relative to benchmark without NZ battery in "Limited thermal" and "100% renewable no peaker" worlds



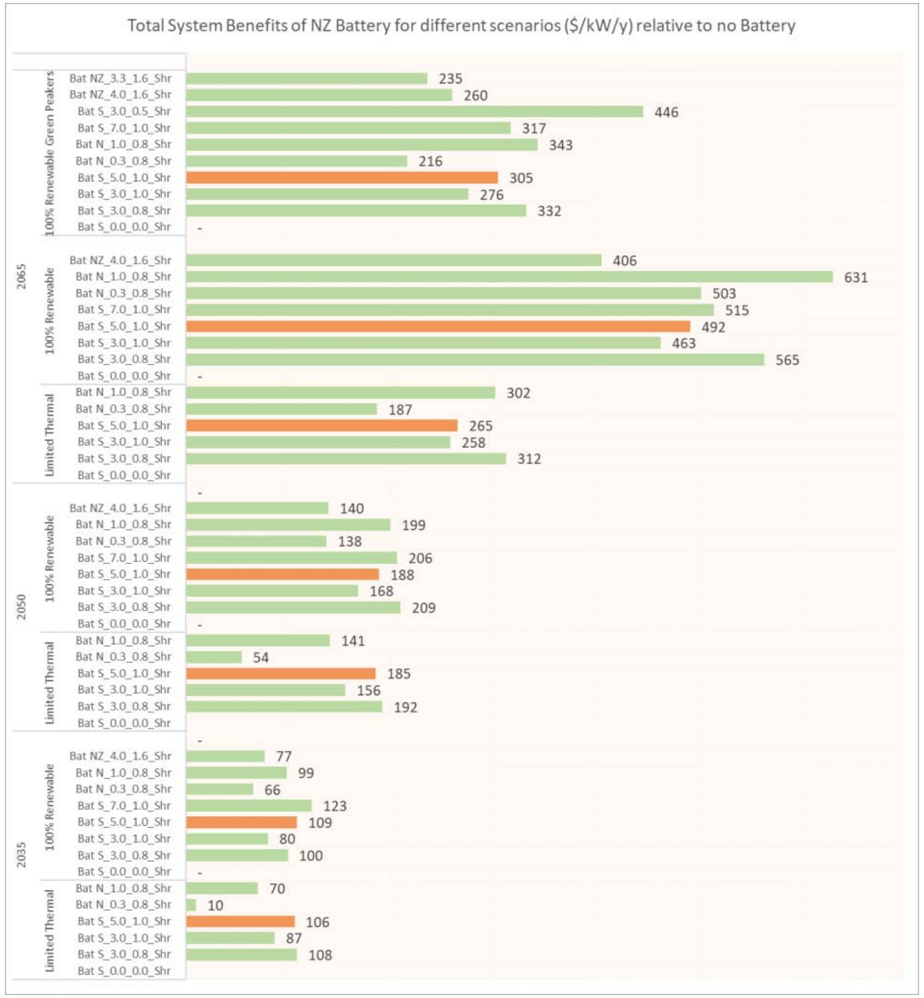
Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

Total system benefits - summary of results

Total System Benefits $m/y



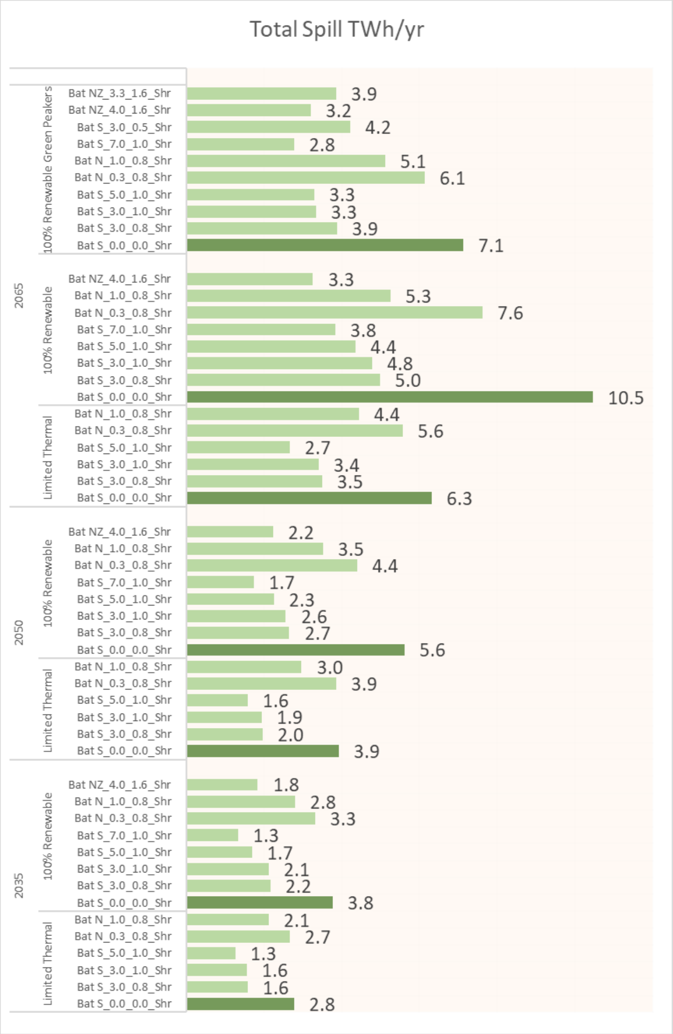
Total system Benefits $/kW/yr (relative to tap size)



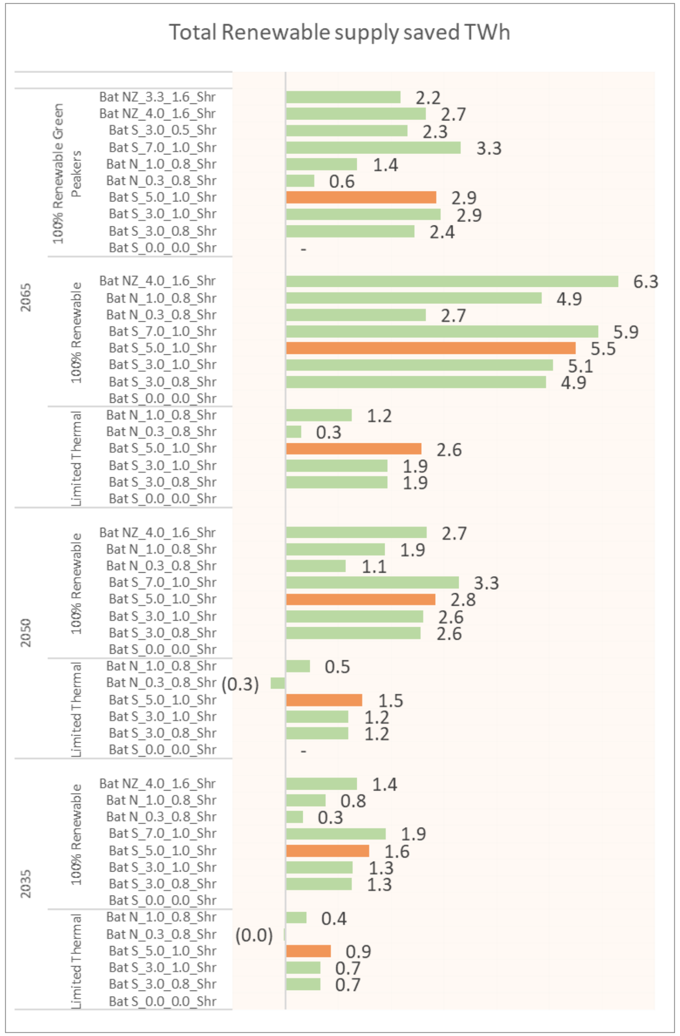
Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). The NZ Battery options are labelled [Island]_[Tank TWh]_[Tap GW]_Pumped storage Operational Mode]

Related results

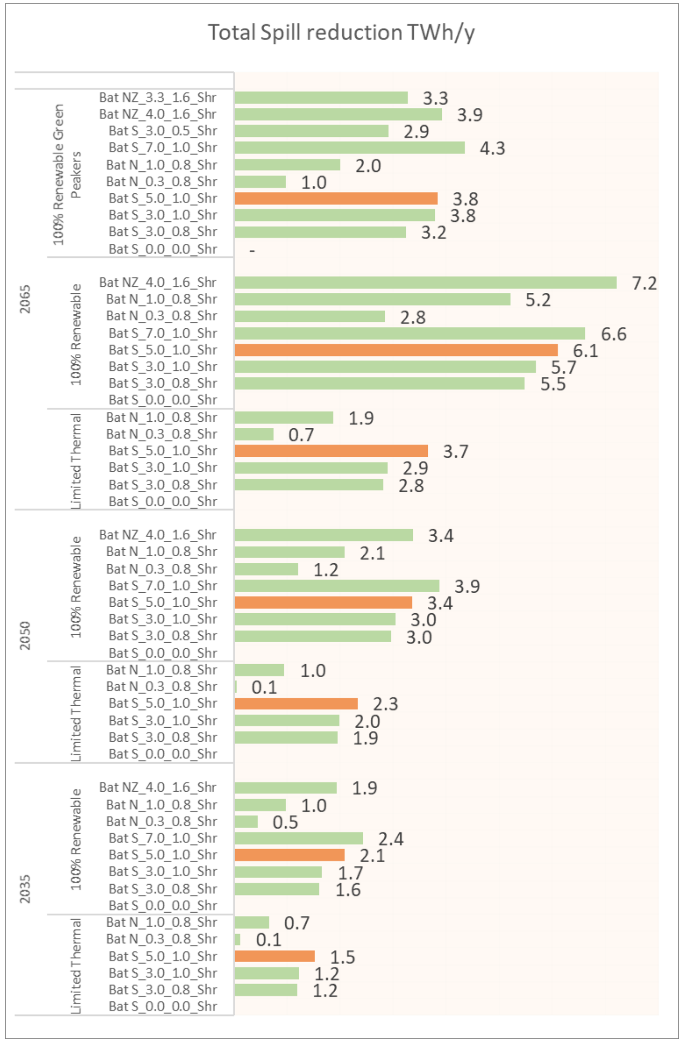
Total “Spill” TWh/y



Total Renewable supply saved (TWh/yr)

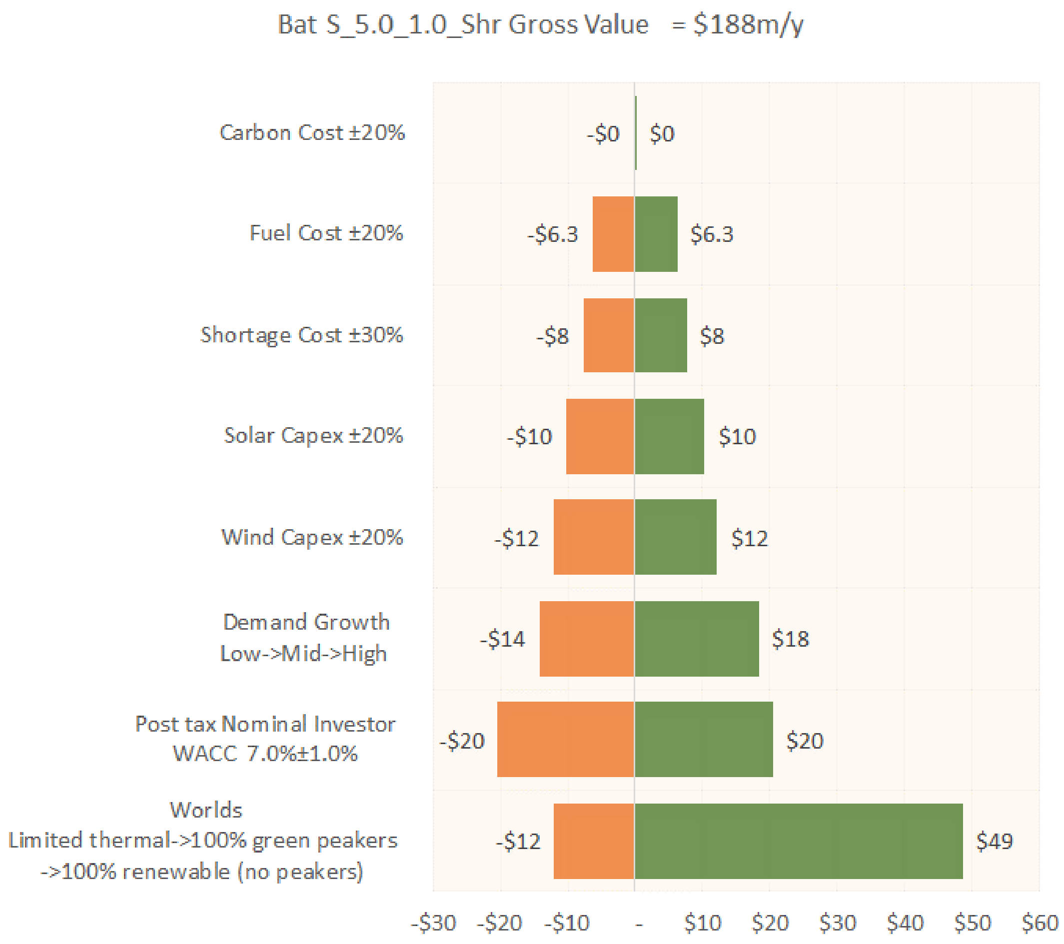


Spill reduction TWh/y



Fuel costs for peakers, rate of demand growth, and cost of capital are the variables with greatest effect on gross benefits

- We have varied key inputs to test their effect on estimated gross benefits
- The inputs with greatest effects:
  - Peaker fuel costs - levelised gross benefits decline by $12 m/yr if peakers can use fossil fuel and pay carbon charges ('Limited thermal' world). Gross benefits increase by $49 m/yr if peakers cannot operate on zero-carbon fuel ('100% Renewable no peaker world')
  - Rate of demand growth - levelised benefits decline by $20 m/yr if it takes five years longer to reach the demand projected for 2050, 2065 etc. Gross benefits increase by $20 m/yr if demand levels projected for 2050, 2065 etc are reach five years earlier
  - Investor post tax nominal WACC - levelised benefits increase by $14 m/yr if WACC is higher by 1%. Gross benefits decline by $18 m/yr if WACC is lower by 1%
- The gross benefit estimates are also sensitive to changes in assumptions regarding generation capital and fuel costs, and demand response costs, and carbon charges - but these have less effect on overall gross benefits than the variables noted above



Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). Central estimate is levelised gross benefit for SI scheme with 3 TWh of storage and 1 GW of capacity in 100% Renewable + Green Peakers world.

Qualitative discussion on effect of modelling assumptions

- In addition to the effects quantified above, we briefly discuss how some modelling assumptions and approaches might have affected results
  - Our modelling only considers HVDC constraints and losses, but properly modelling the full AC network will probably reduce the benefit of South (and possibly North) Island options. Or an alternative way of looking at it: our modelling does not include the costs of AC network upgrades to enable constraint free operation of South (and possibly North) Island options
  - Our main model assumes perfect foresight within each modelled week. This will lead to more efficient dispatch than could occur in reality. Such an assumption will lead to underestimating the benefits of highly responsive plant. Whether this over or underestimates the benefits of NZ Battery will be determined by how quickly it can respond to changes in residual demand, relative to other sources of flexibility such as existing hydro and new small-scale batteries.
  - Our main model assumes that investment will occur when commercially economic to do so. We believe this to be a reasonable assumption, but may be somewhat bullish (i.e. it assumes investment happens more quickly than might occur in reality), given various impediments to investment. If investment is more sluggish than assumed then the benefits of NZ Battery will be higher than modelled.
  - Our main model assumes an SRMC based dispatch order (where relevant) and heuristic water values - including for NZ Battery. Actual competitive behaviour will likely diverge from this ideal and we do not have a clear view on whether this will result in lower or higher benefits of NZ Battery.

Results from the shadow model

We have also run a shadow model alongside the main model

- Why a shadow model?
  - Allows us to cross-check key results from the main model
  - Developed independently from main model
  - It has strengths and weaknesses relative to the main model
- Similarities with main model
  - A “stack” model that dispatches plant according to offers derived from SRMC or water values
  - Two island transmission system with HVDC losses and constraints
  - Uses historical hydrological inflows as indicator of future inflows
  - Uses demand response (and shortage) as ultimate/most expensive dispatch resource
- Differences from main model
  - Models each hour in year in chronological order (main model is chronological by week)
  - Models HVDC reserve requirement and co-optimizes energy and reserve dispatch (main model uses a simplified approach)
  - Optimizes generation planting based on economic cost (main model uses revenue adequacy, based on water values and SRMC, test to determine planting)
  - Implements “fuzzy” battery scheduling using inaccurate wind, solar and demand forecasting (main model has perfect foresight within week)
  - Independently derived inputs, such as new generation build costs and new wind build profiles
  - Takes longer to run!!!

Key results from shadow model

- Derives lower estimates of gross benefits from NZ Battery options compared to main model
  - Calculated benefits are approximately 2/3 of main model
  - This is primarily due to differences in new renewable generation costs (i.e. lower overbuild costs)
  - The shadow model also assumes less seasonality for demand in future years, which leads to less benefit to shifting energy between seasons
- The shadow model derives very similar conclusions for the *relative* merits of different pumped storage options:
  - A smaller North Island option produces similar benefits to a larger South Island option
  - Compared to the default 5 TWh / 1 GW South Island option:
    - A 3 TWh option in the South Island has about 15% less benefit
    - A 7 TWh option in the South Island has about 10 % more benefit
    - A 500 MW option in the South Island has about 15% less benefit

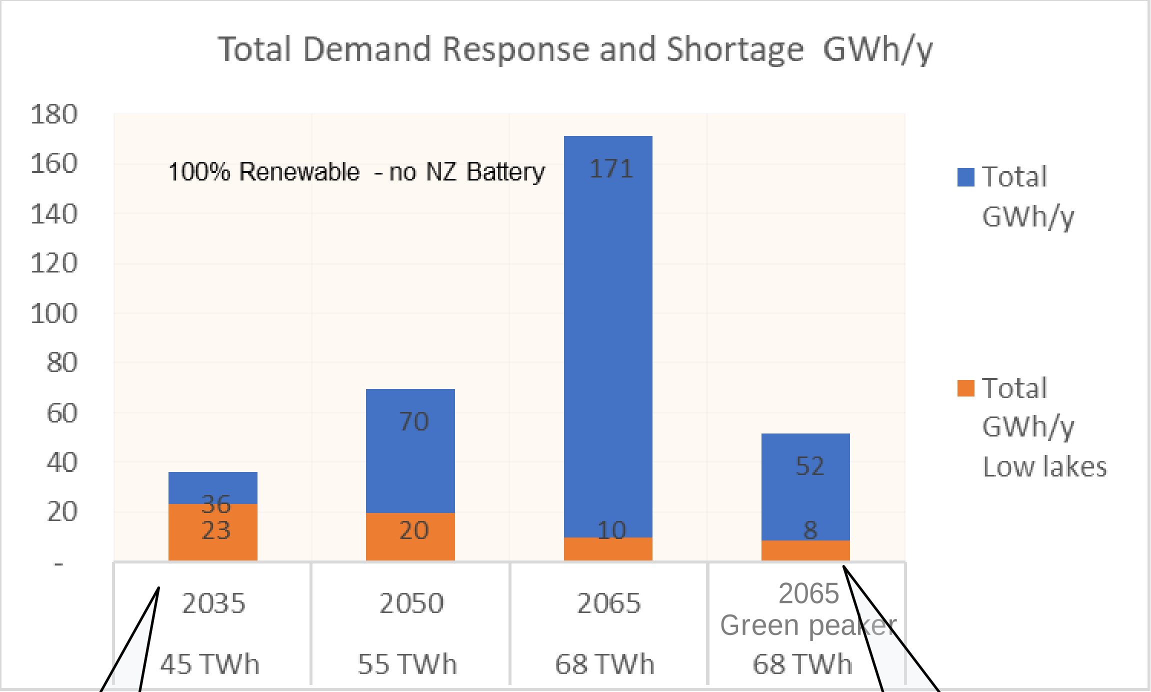
- We also used the shadow model to test two additional scenarios:
  - Increasing the capacity of the HVDC by 200 MW - which increased benefits by 15% relative to the 5 TWh / 1 GW option
  - Relocating the 5 TWh / 1 GW option to the North Island - which increased benefits by 45%

THE CHANGING NATURE OF DRY YEAR AND CAPACITY BACKUP ISSUES

NZ's storage needs are expected to change over time

NZ's storage requirements will progressively change as the nation decarbonises - shorter term flex will become increasingly important and the need for longer cycle 'dry year' flex will decline in relative (and absolute) terms

- By 2065, the majority of total electricity production is projected to come from wind and solar generation
- This means NZ's system will become more like that of Germany - in which the challenge is *dunkelflaute* events – calm/dark periods with low wind/solar generation
- To achieve capacity adequacy in this type of system, it will be economic (i.e. necessary) to have significant levels of renewable 'overbuild'
- Indeed, the overbuild is expected to become sufficiently large to start to shrink the dry year challenge - basically dry years will cause wind/solar spill to decline rather than manifesting as energy shortages
- This phenomenon is evident by the comparing the causes of demand response in the modelled results (see chart)
- This dynamic also explains why benefits are driven more by tap size than tank size - since big taps are more useful than big tanks for getting through 'dunkelflaute' events



Over 65% demand response / shortage is due to 'dry years' in 2035…

By 2065 'dry years' account for around 15% of demand response / shortage - indeed the absolute volume also declines

Examination of chronological results shows the same phenomenon - we move from dry year (low lakes) to dunkelflaute events as the main challenge

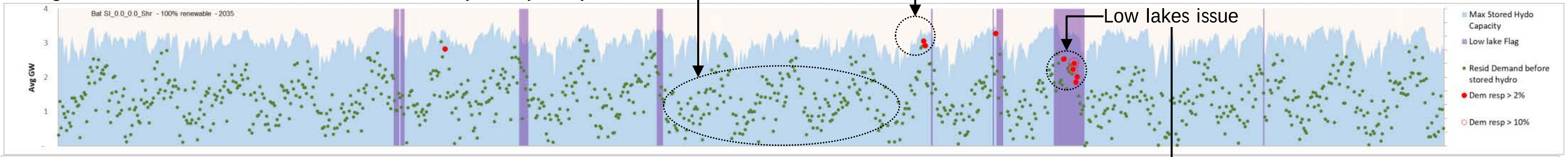
The average weekly GW of capacity that needs to be met from hydro releases from storage after geothermal, wind, solar and hydro tributaries is show by the green dots. The shaded blue area is an indicator of the maximum weekly capacity of the hydro system after tributaries. Weeks with demand response or shortage are indicated by red dots. A capacity issue is indicated when the red dots are close to the maximum hydro capacity indicator, whereas a low lake level driven demand response is indicated when the red dots are in the purple bands.

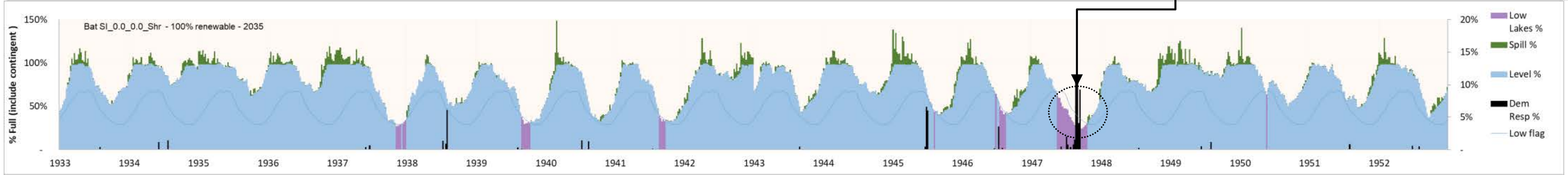
2035

The green dots “within the blue” can be handled by the hydro system

Capacity risk issue

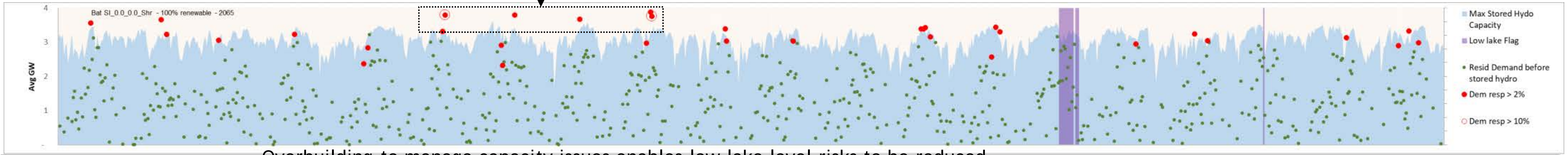
Low lakes issue



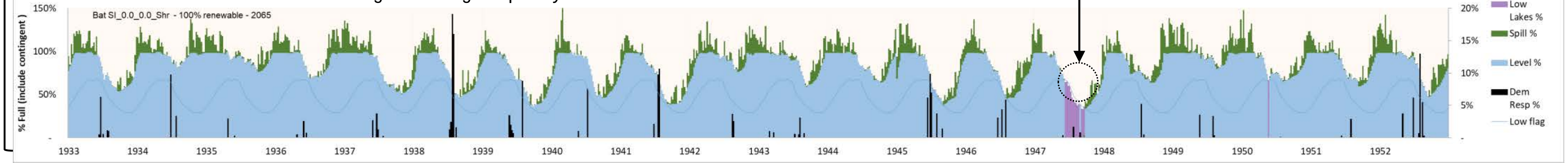


2065

Significant weekly capacity issues



Overbuilding to manage capacity issues enables low lake level risks to be reduced.



A subset of weather years by week

In 2035 the majority of the weekly demand response events are driven by low lake risk, as the residual demand for hydro releases is within the hydro capacity envelope. Spill is moderate.

In 2065 the majority of the weekly demand response events are driven by capacity issues as the residual demand for hydro releases is often outside or near the top of the hydro capacity envelope.

Overall levels of economic demand response increases as the level of overbuilding and spill required to meet capacity issues increases.

The economic level of demand response increases with electrification demand, but this would be avoided if green peakers were available to meet residual capacity risks.

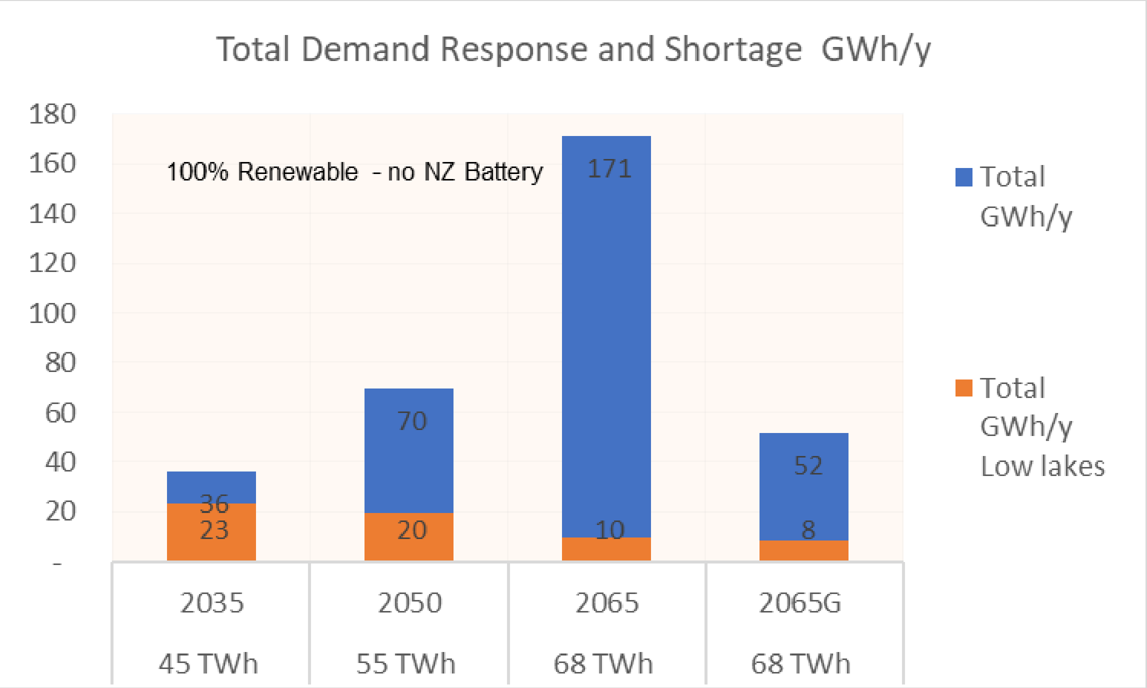
There is a significant increase in demand response as electricity demand rises.

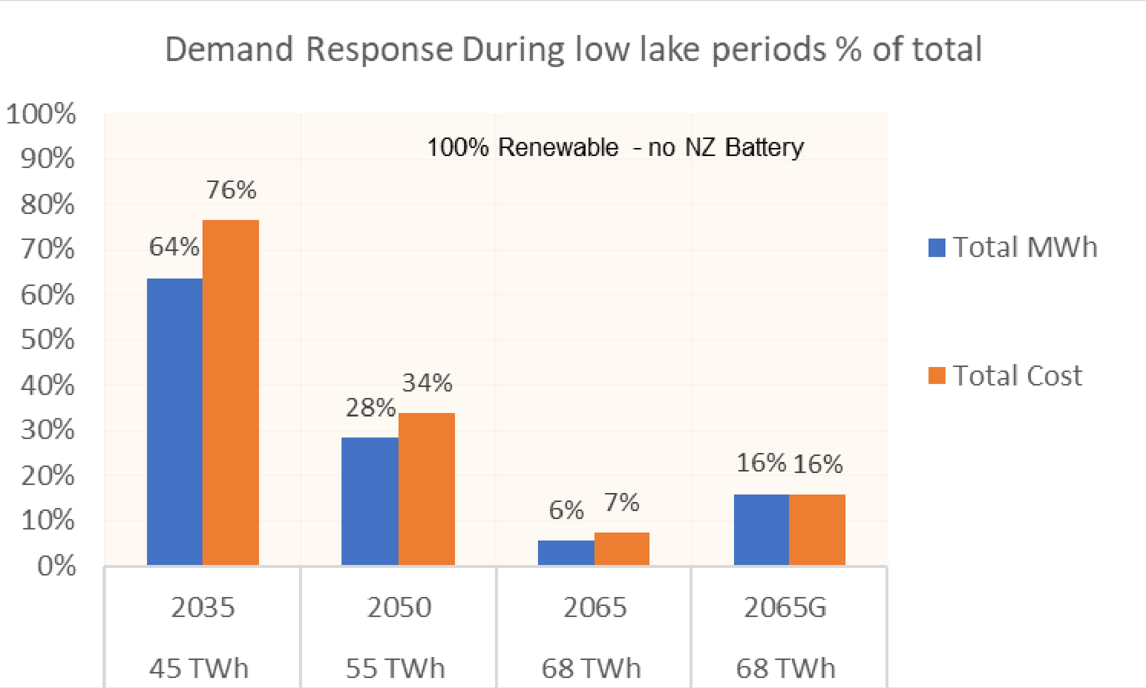
In 2035 the need for demand response is mostly in relation to dry year events and short run capacity issues can be met through the existing hydro system and managed EV charging, batteries associated with rooftop solar, new grid 4 to 12hr batteries as **required and modest increases in spill. The level of "dry year" demand response** required falls over time.

By 2065 a greater proportion of intermittent supply causes a significant rise in capacity issues in weeks with a combination of low wind and high demand. This is partly managed by overbuilding new renewables, but the cost of this rises with the % intermittency.

The share of demand response due to dry year issues falls from above 60% in 2035 to less than 10% the scenario corresponding to full electrification (2065) where the increasing capacity issues are managed through overbuilding only.

Where the capacity issues can be addressed through new green peakers the % of demand response required for managing dry year risks rises, but only because the economic level of capacity related demand response is much lower. Note that the equilibrium level of demand response in dry years also falls as green peakers can meet both short run and long run back up requirements.



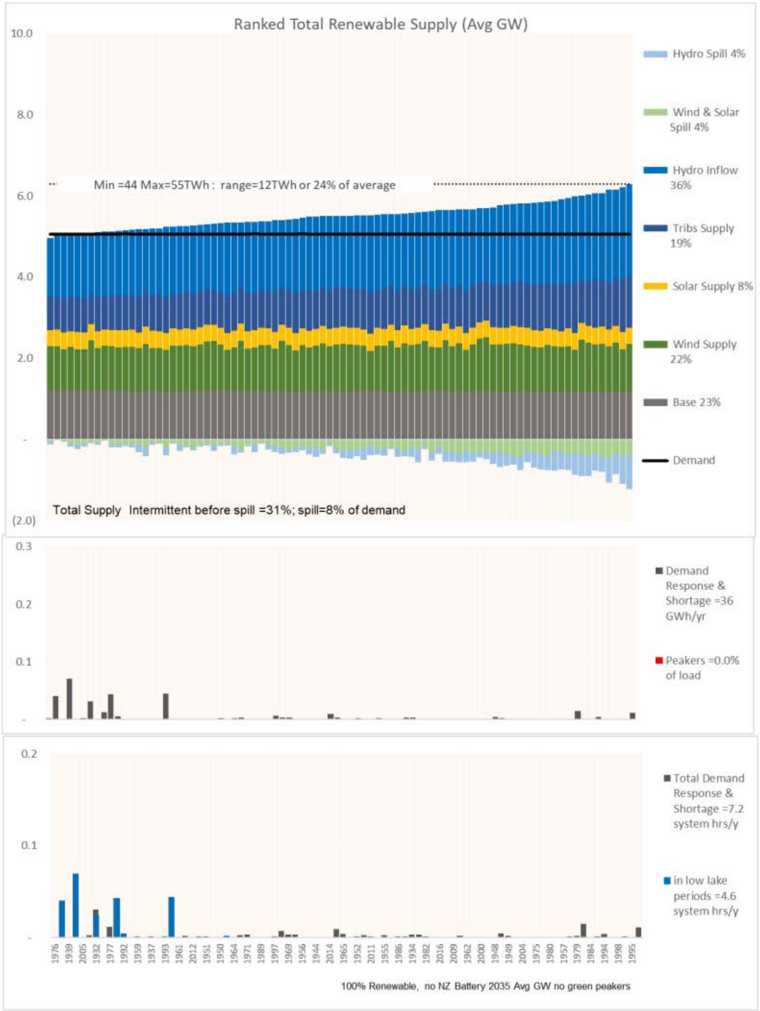


Ranked annual renewable supply and green peaker, demand response and shortage

concept consulting

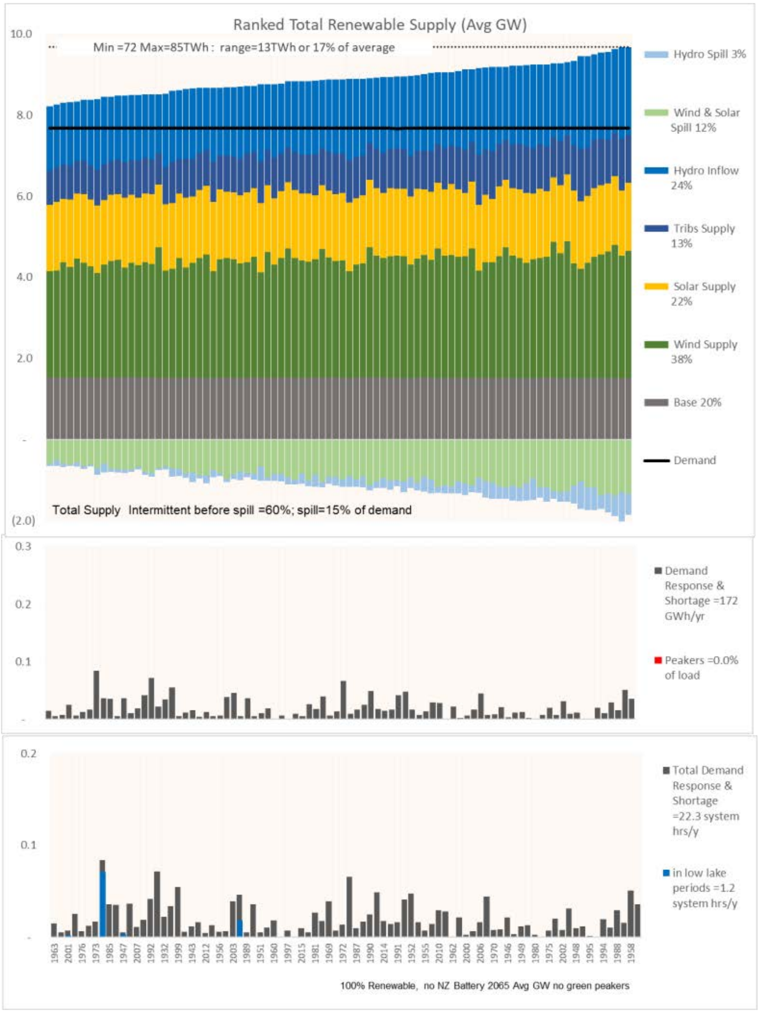
JC2

2035 - 100% Renewable - no peakers



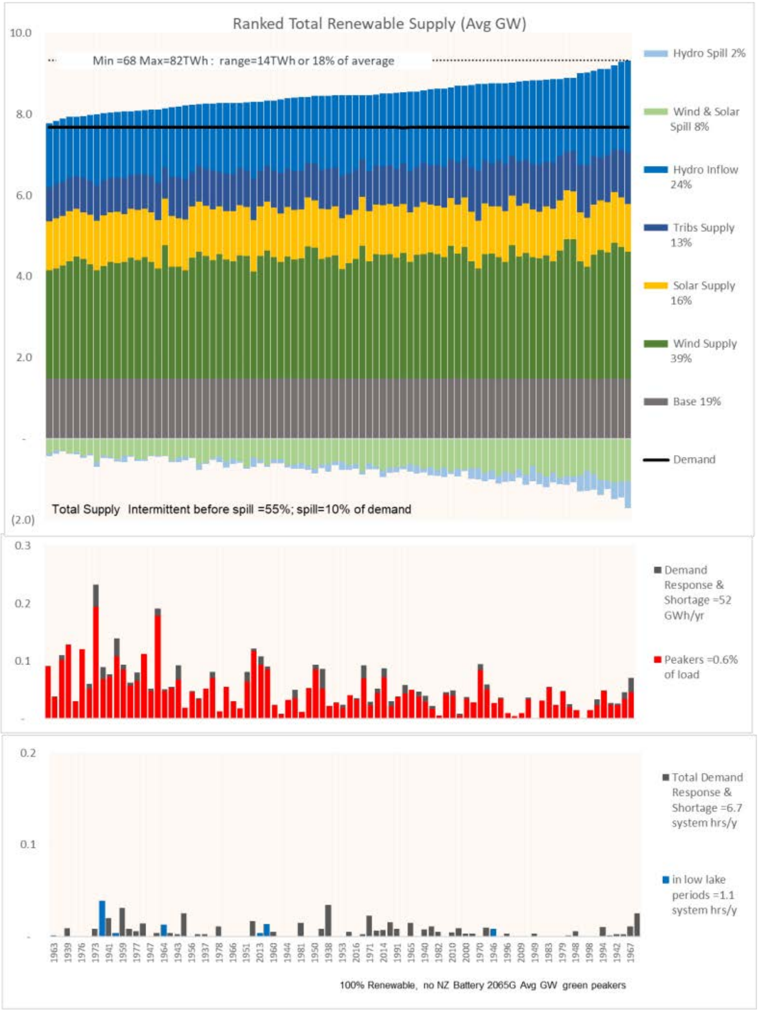
In 2035 intermittent supply is 31% of demand, up from 7% in 2020 as a result of closure of thermals and closure of Tiwai. Spill is 8% of demand.

2065 - 100% Renewable - no peakers



In 2065 intermittent supply is 60% of demand, up from 31% in 2035. Spill is increased to 15% of demand.

2065 - 100% renewable - green peakers



Green peakers allow the renewable overbuild to be reduced so intermittent supply only increases to 55% of demand. Spill is reduced 10% of demand. Peakers are less than 1% of load.

Detailed results for a 5 TWh,1 GW option in the South Island

This section takes a deeper dive into a South Island option with 5 TWh of storage and 1 GW max output

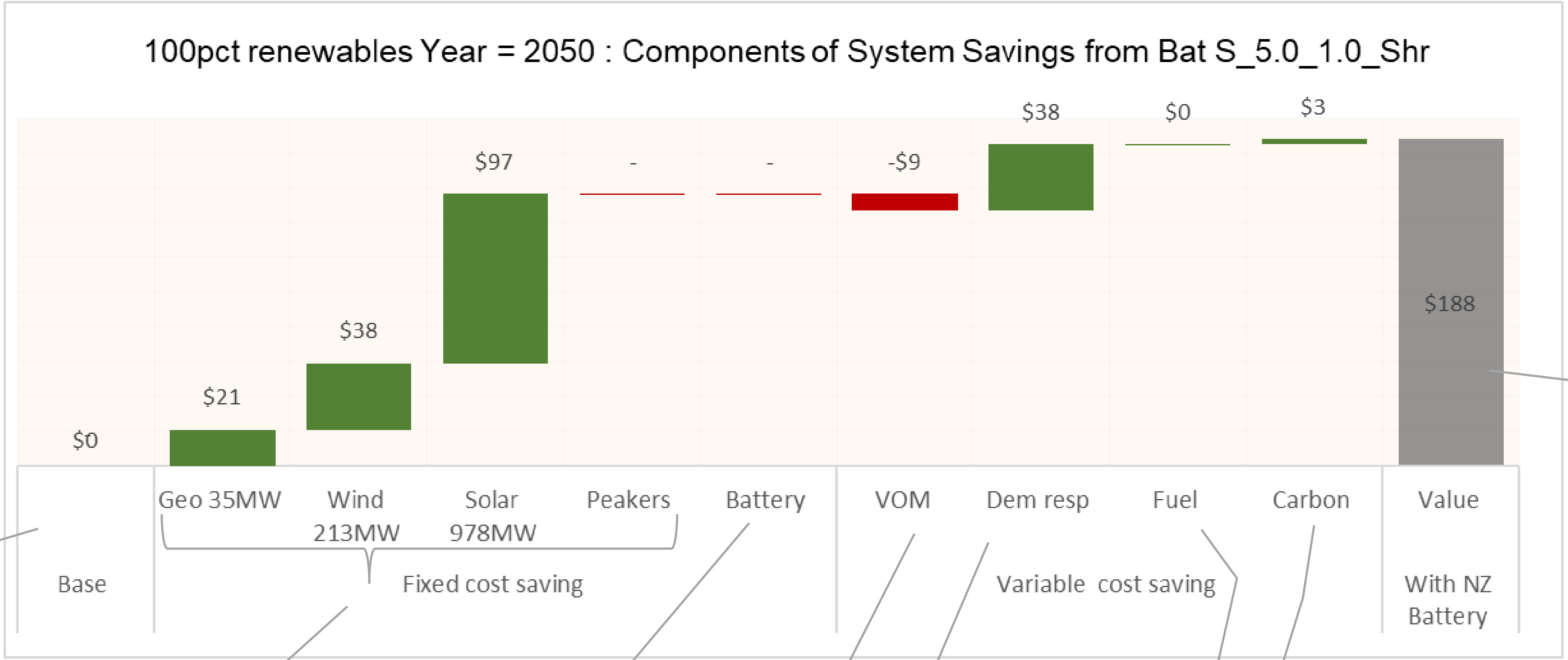
- This section takes a more in-depth look at a single South Island option (to avoid being overwhelmed by the detail of many alternative options

- The choice of option is somewhat arbitrary because we have no information on NZ Battery costs, and therefore cannot focus on the option which appears to have greatest net benefits

- Given the absence of any preferred option at this stage and no information about the technical opportunities in the North Island, we have chosen to examine a South Island option with 5 TWh of storage and 1 GW of capacity (noting this may be somewhat oversized unless there are marked economies of scale)

- Looking at the detailed results allows us to examine the underlying drivers - which is useful in its own right but also tests the robustness of the modelling approach

We start by decomposing the benefits for a 5TWh/1GW Battery in South Island in 2050 - **the chart shows the way we decompose benefits…**



Sum of parts = gross benefit of NZ Battery

Treat cost of a 100% renewables system without NZ Battery as the base line - and measure deviations from this base line if NZ Battery is available

Capex savings from geothermal, wind, solar & peaker plant which is not needed

Capex savings from smaller scale storage batteries which are not built

Extra variable operating costs

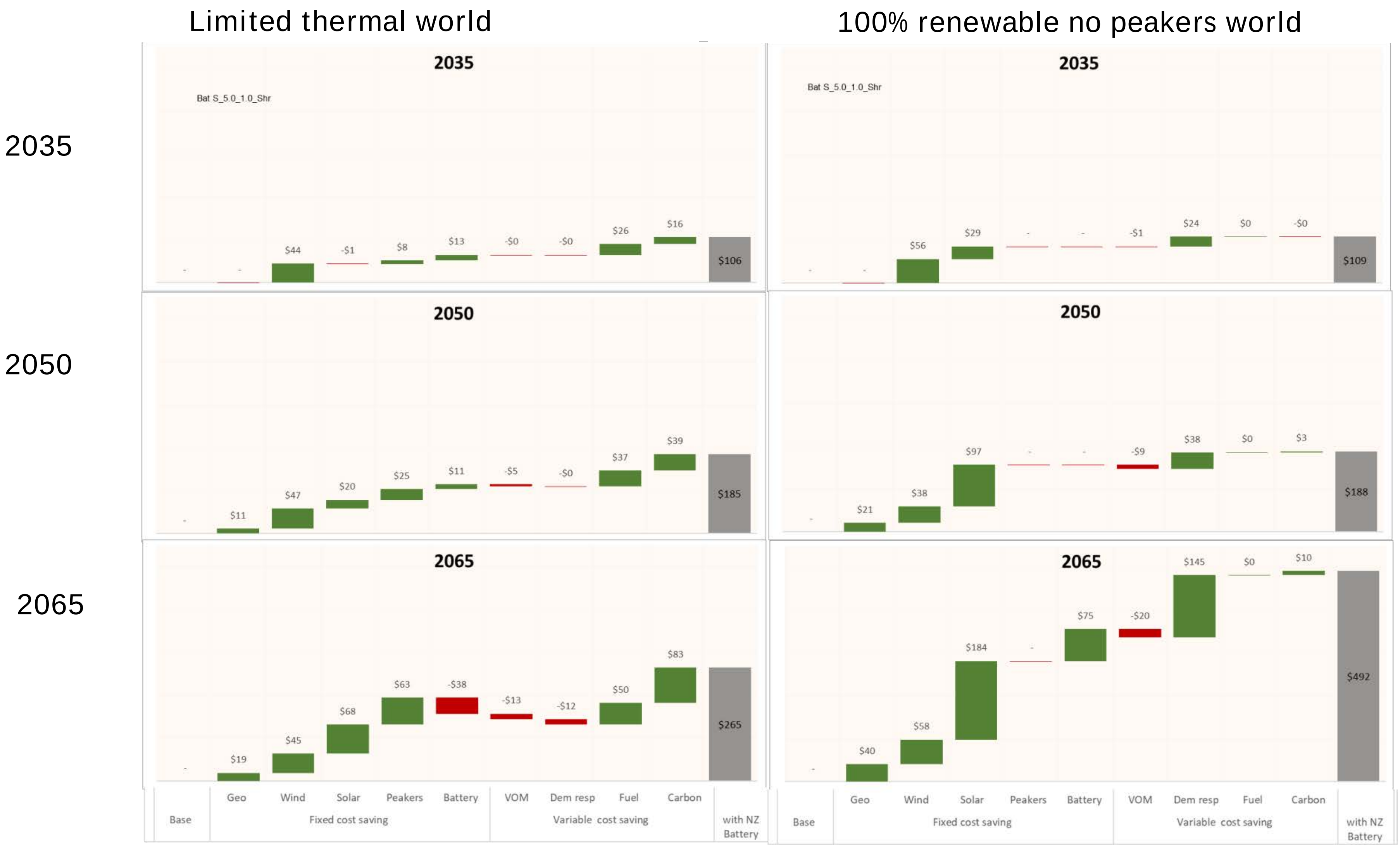
Avoided demand response costs

No change in fuel costs

Savings in geothermal CO_2 emissions

Charts show how the sources of benefit for 5TWh/1GW Battery in South Island change over time and between the two different worlds

- Analysis shows how sources of benefit change over time - and alter between the two different ‘worlds’
- In ‘Limited Thermal’ world, NZ Battery mainly saves capex and fuel costs
- In ‘100% renewable - no peakers’ world NZ Battery mainly saves capex and demand response costs



Note: The vertical scales on the charts are the same

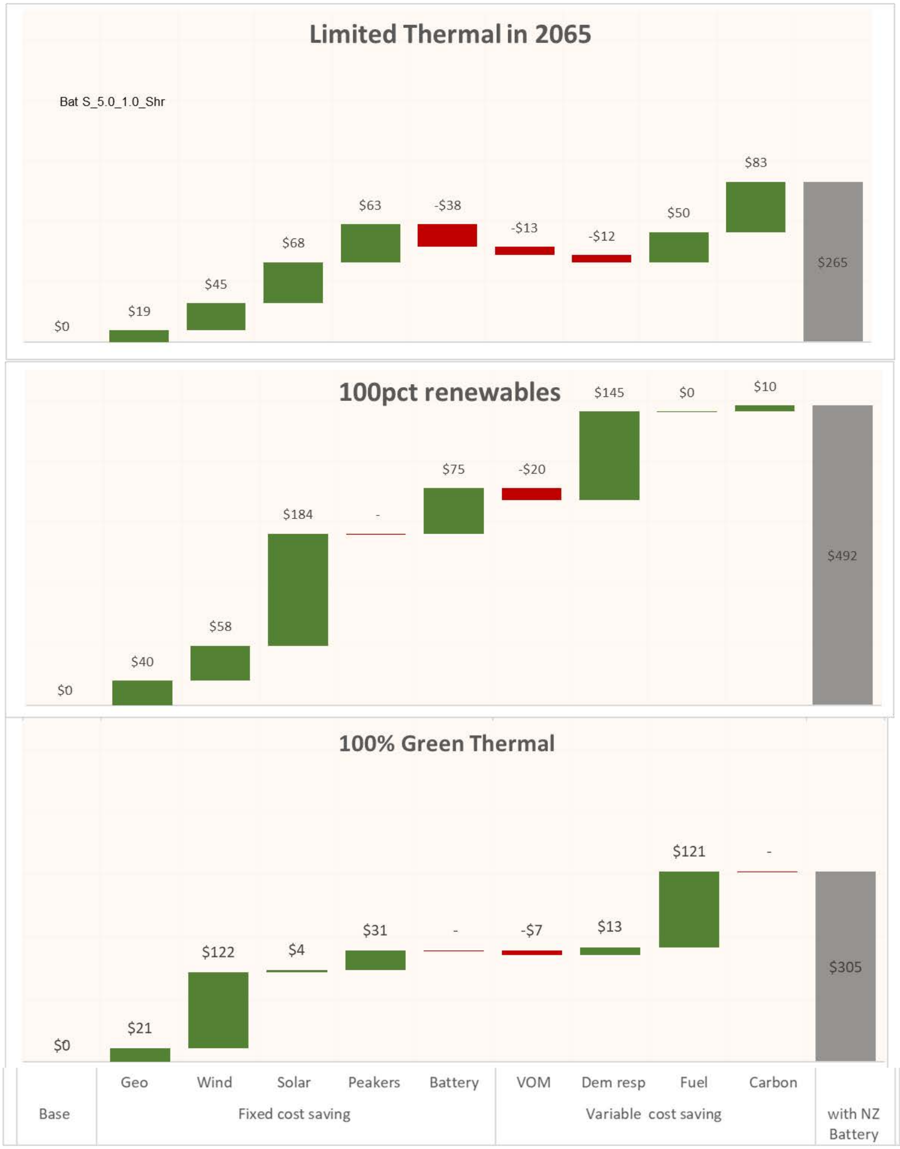
2065 benefits are sensitive to whether an alternative zero carbon option is available by then such as green peakers

- As discussed earlier, the gross benefits are sensitive to assumption about the availability of any alternatives to pumped storage which are also zero carbon
- This sensitivity is modelled by considering a ‘100% renewable + green peakers’ world where peakers can run on hydrogen or biofuel at $45/GJ
- Gross benefits for NZ Battery (in 2065) in a ‘100% renewable green peaker’ world are:
    - $40 million higher than in a ‘Limited thermal’ world
    - $187 million lower than in a ‘100% renewable – no peaker’ world.
- Comparing the two 100% renewable worlds, the availability of green peakers would reduce the capex savings on generation/smaller batteries that NZ Battery would otherwise create

Limited Thermal world

100% renewable - no peakers world

100% renewable - green peakers world



Note: The vertical scales on the charts are the same

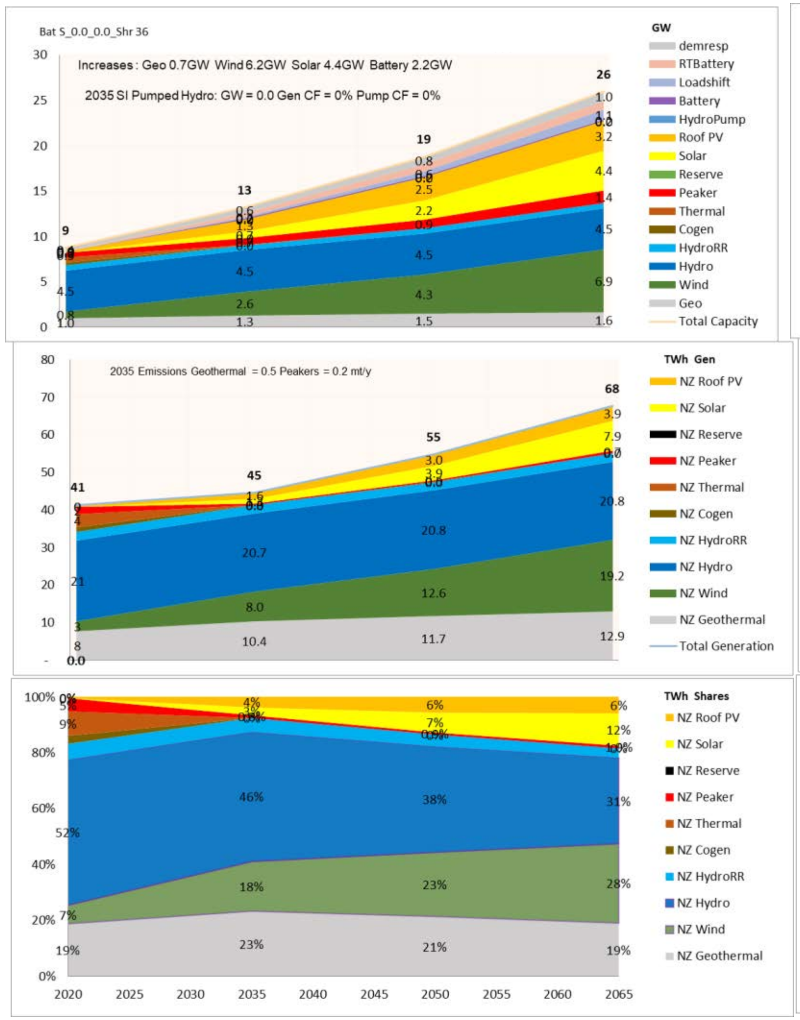
Charts show the projected system build to meet demand growth without NZ Battery…

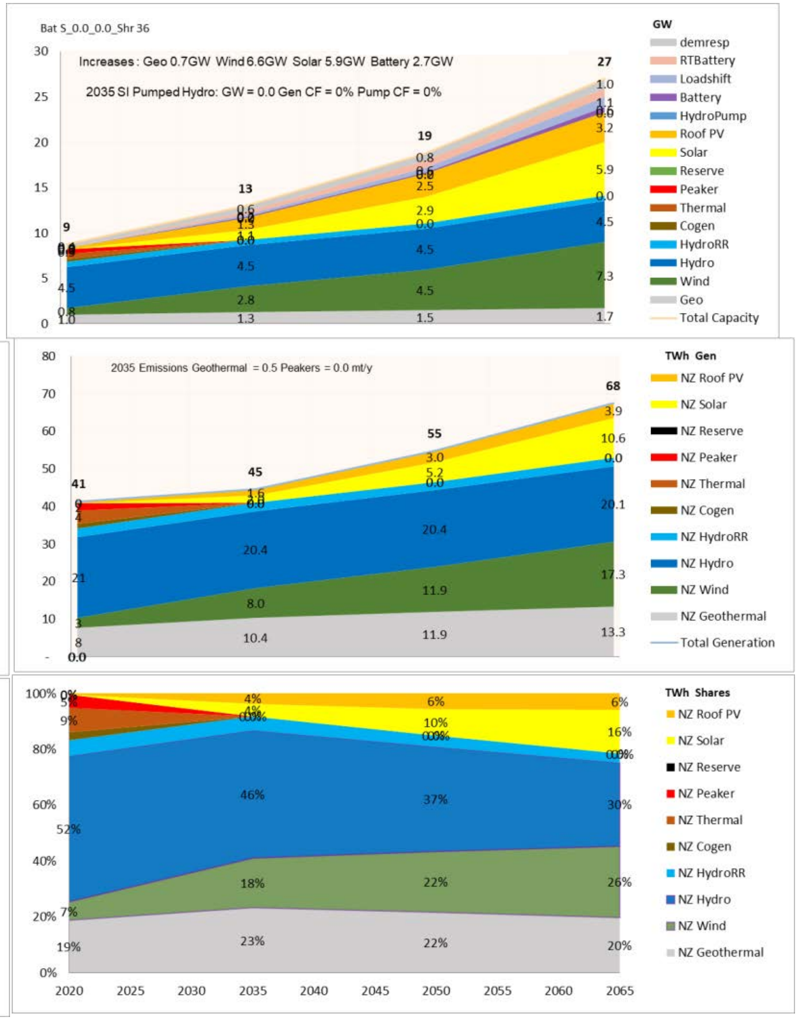
Limited Thermal World	100% Renewable - no peaker World	Comments:

Capacity GW

Energy TWh

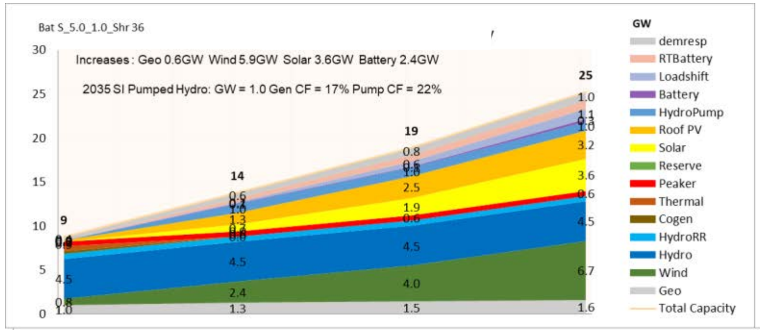
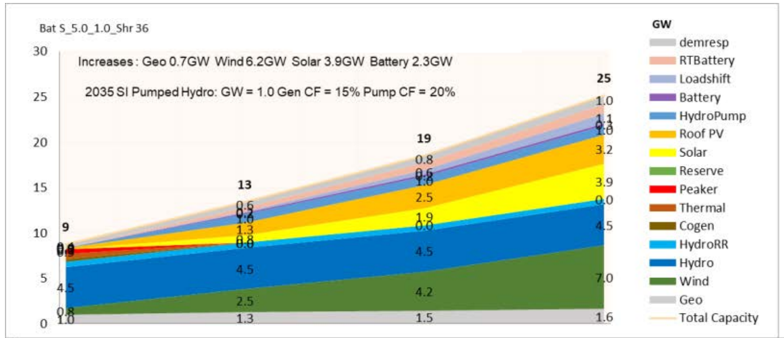
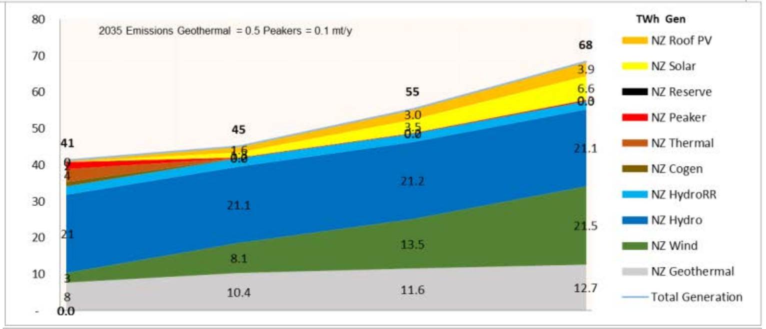
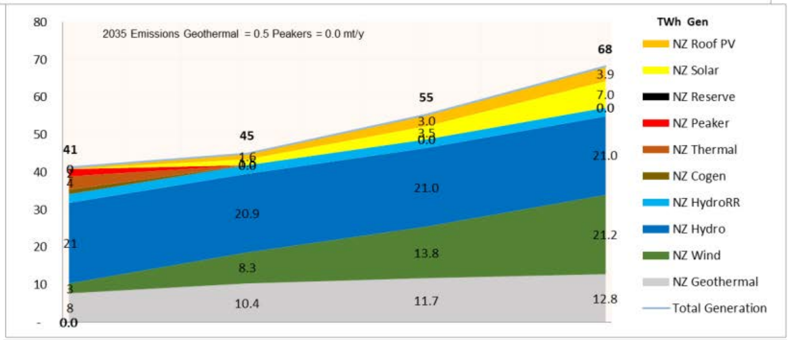
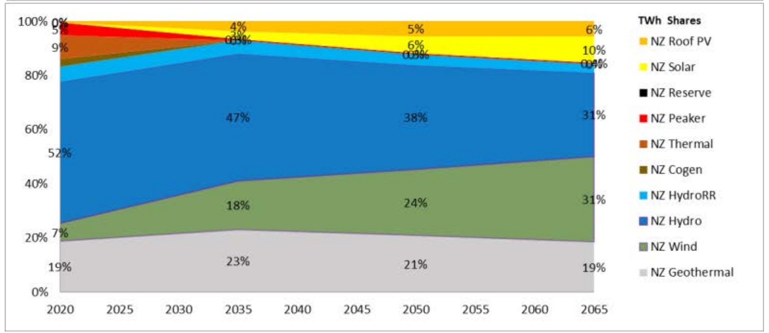
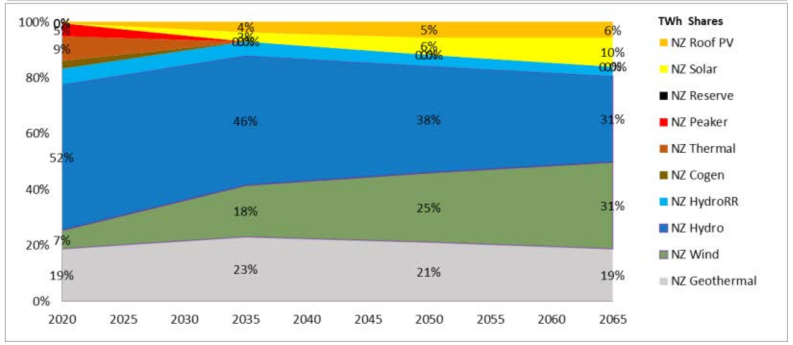
Energy shares %





- Limited Thermal has additional 0.9GW peaker capacity added to meet the firming requirements for the additional wind and solar required to meet demand growth up towards 70TWh by 2065.
  - Despite this the % energy share thermal remains below 2% - implying greater than 98% renewable.
  - Peaker emissions are below 0.3mt/y, lower than geothermal emissions at 0.6mt/y.
  - Wind increases 5.4GW, grid solar increases 4.2GW and geothermal increases 1.2GW
  - There is a 2.7GW increase in 5hr load shifting, 5 and 12hr batteries and demand response.
  - Intermittent supply increases from 7% to 46%.
- In the 100% Renewable World peakers are not allowed so there is 2.9GW extra battery capacity (including swap from 5hr to 12hr storage) and extra renewable "overbuilding"
  - Wind increases 5.9GW, solar increases 5.8GW and geothermal increases 1.3GW.
  - This overbuilding enables security to be met, at the expense of additional "spill".
  - Peaker emissions are zero, but 0.6mt/y emissions from geothermal continue.
  - Intermittent supply increases from 7% to 47%.

System build will change if "NZ Battery" is available…

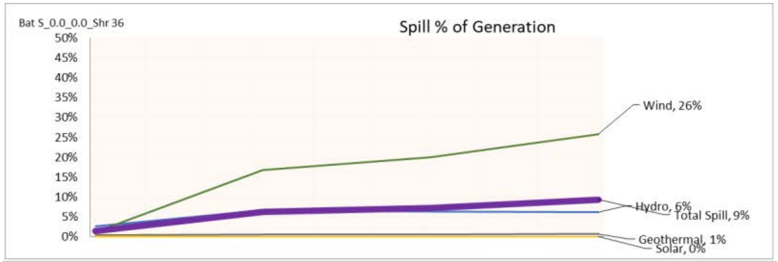
	Limited Thermal + 5TWh/1.0GW SI battery	100% renewable no peaker + 5TWh/1.0GW SI battery
Capacity GW		
Energy TWh		
Energy shares %		

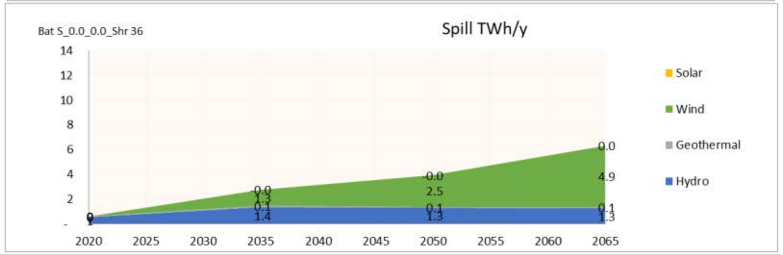
Comments:

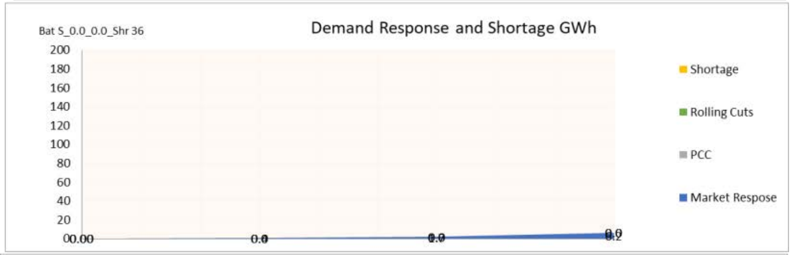
- A 5TWh/1.0 GW SI battery would enable some investment in renewable generation capacity to be deferred by 2065:
  - Around 2.1TWh/yr renewable energy investment can be delayed in the limited thermal world, and
  - 5.8TWh/y renewable energy investment can be delayed in the 100% renewable world.
  - The NZ Battery storage increases load by around 0.7TW/yr and reduces "spill" by around 3.4 to 6.4TWh/y by 2065.

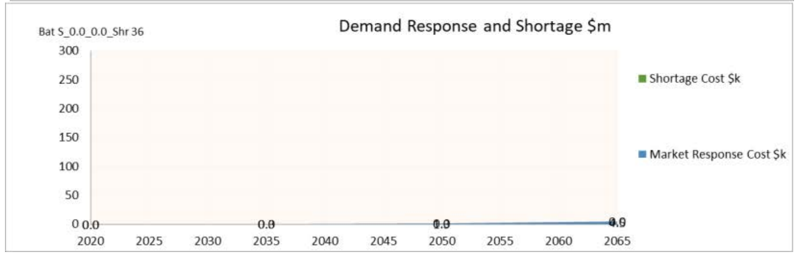
Charts show 'spill' and shortage in the Limited thermal and 100% renewable (no peaker) worlds
assuming NZ Battery is not available

'Spill' increases modestly over time in the Limited thermal world without NZ Battery

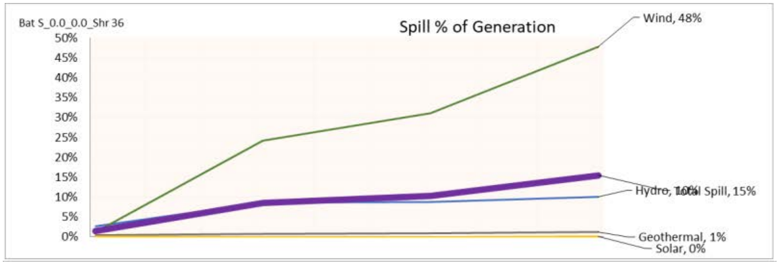


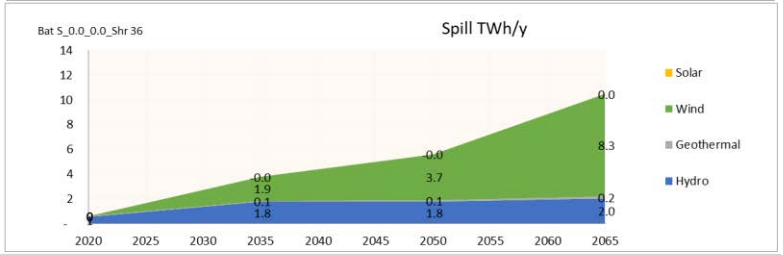


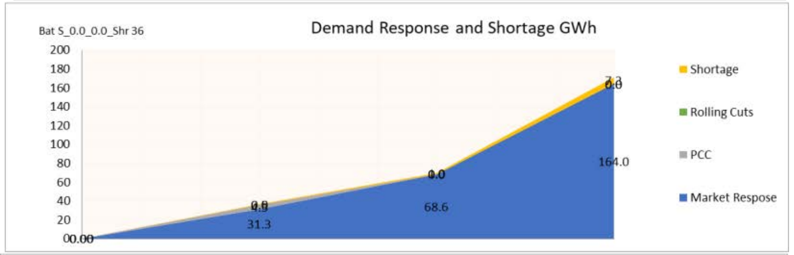


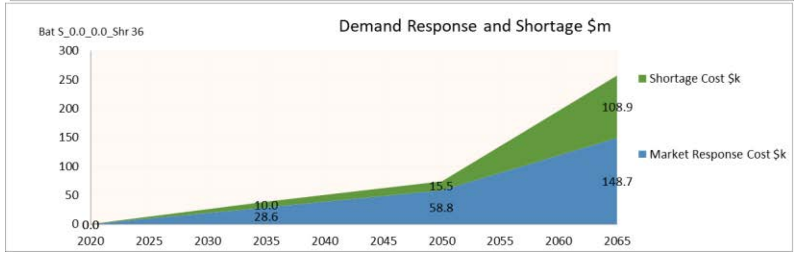


'Spill' increases much faster in the 100% renewables world without NZ Battery









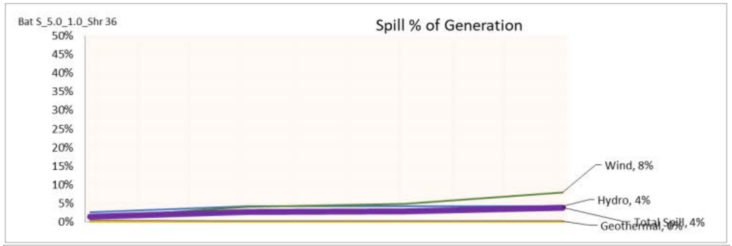
Comments

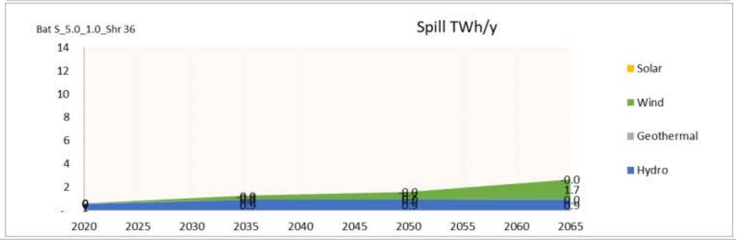
- Note 'spill' is actually wind/solar/geothermal or hydro being dispatched off. We assume these renewable resources bid into the market at the avoided variable costs, which are assumed to be of the order of $5-10/MWh (eg variable O&M, carbon charges, royalty payments etc).
  - The assumed bidding affects the allocation of 'spill' between the different plant but does not significantly impact the total "spill".
- Even in the Limited Thermal world there some 'spill' that is economic. However in the 100% renewable world the 'spill' increases substantially as renewable 'overbuild' is required meet short and long term security of supply.
- There is a trade off between higher 'spill' and increased demand response and shortage (conservation campaigns etc).
  - In the Limited thermal world the demand response and shortage can be virtually eliminated by building addition peakers and incurring high cost peaker fuel cost occasionally
  - In the 100% renewable world, there is more 'overbuild' until a point is reached when it is economic to incur additional demand control costs occasionally rather than continue to overbuild renewables.

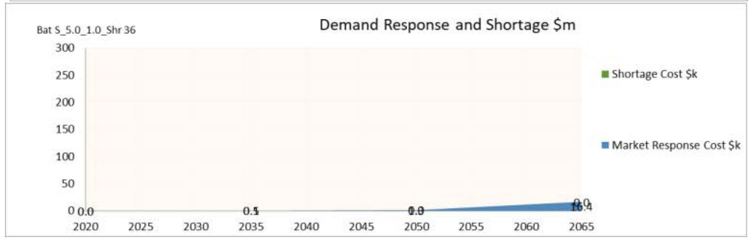
Notes: Shortage cost in the lowest chart includes conservation campaigns, rolling cuts and shortage.

‘Spill’ and shortage are reduced by NZ Battery in both worlds, but especially 100% renewable world

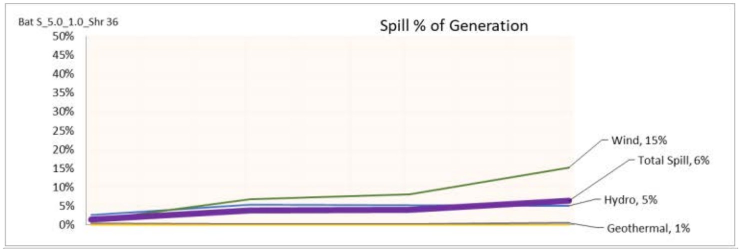
NZ battery enables spill to be moderately reduced and thermal costs can be saved in limited thermal world

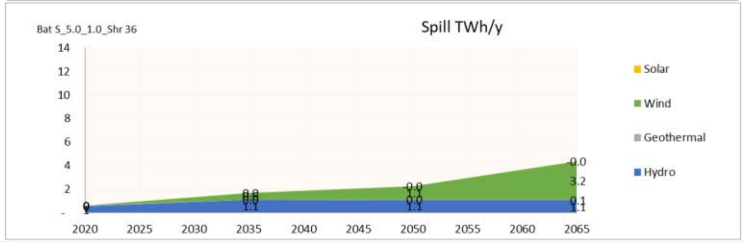


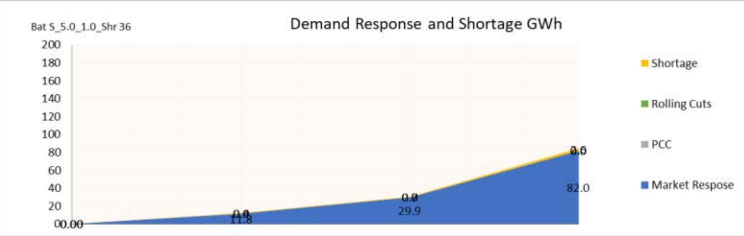


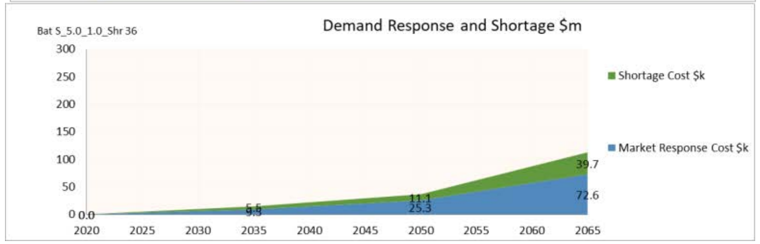


NZ battery can significantly reduce spill (from overbuilding) and shortage in the 100% renewable world









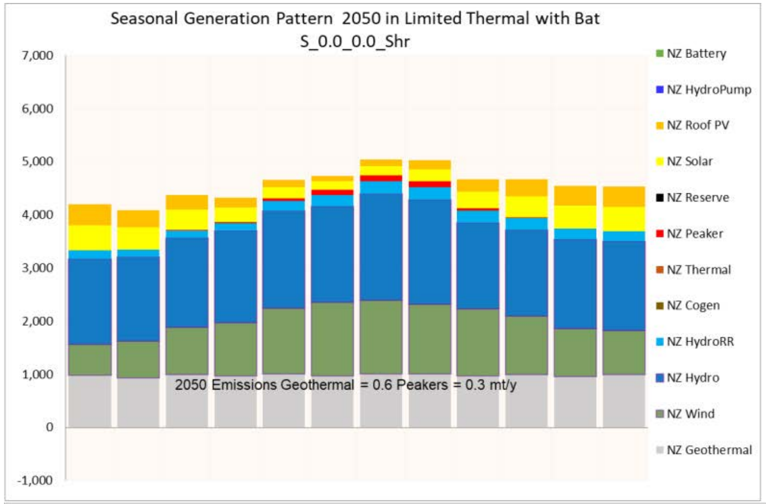
Comments

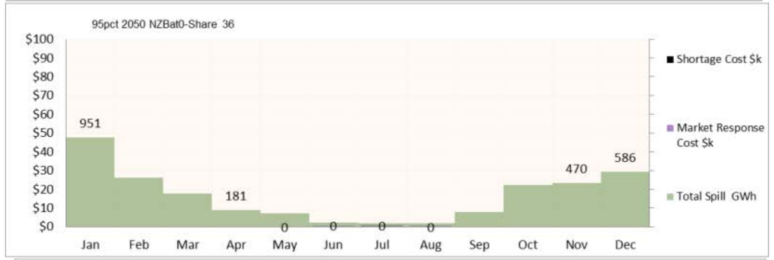
- Chart show how the levels of spill and demand response/shortage are substantially reduced by an SI 5TWh/1.0GW Battery scheme.
- The system benefits provided by this scheme are reflected in the reduction in new renewable investment required and the reduction in demand response/shortage costs.
- In the Limited thermal world there are also fuel and carbon cost savings, and shortage costs can be reduced as additional gas peakers provide a low capex option to maintain reliability (albeit at a higher running cost).
- Even with NZ Battery, it is still economic to have a modest degree of overbuilding renewables at the cost of modest increases in spill, offset by savings in fuel and/or shortage - in both worlds.

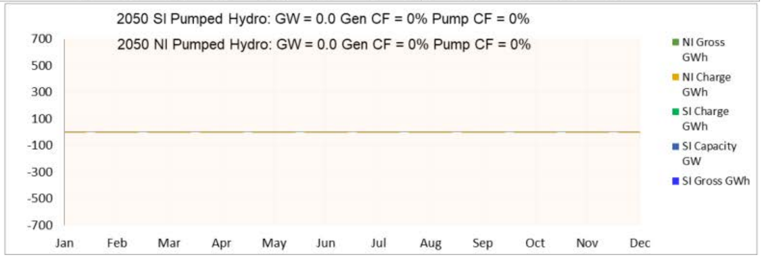
Notes: Shortage cost in the lowest chart includes conservation campaigns, rolling cuts and shortage.

Seasonal patterns of operation in 2050 without NZ Battery

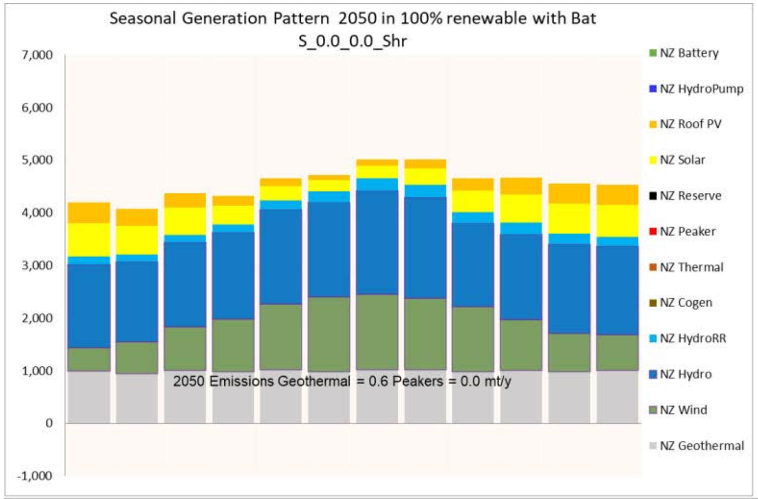
Limited Thermal World

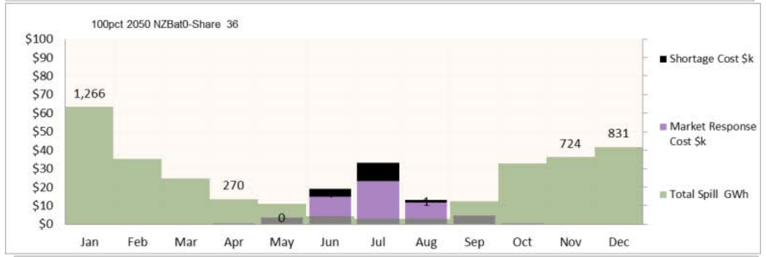


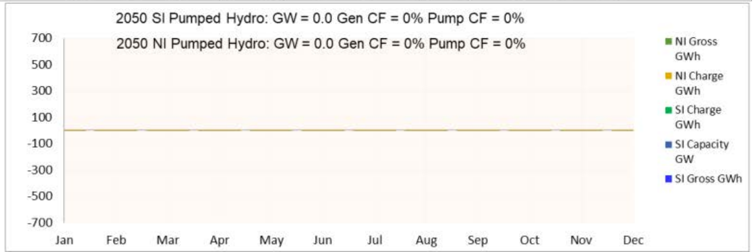




100% Renewable (no peaker) World

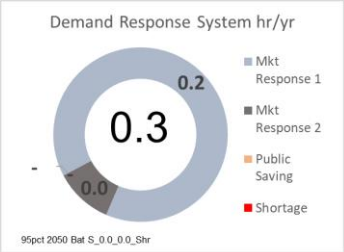


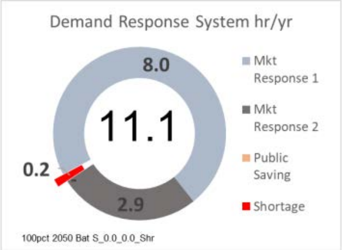




Comments

- The chart shows the seasonal operation in each world in 2050 without a pumped hydro.
  - Note that the spill is greatest in the spring summer when demand is low, solar is greatest, and lakes are getting filled ready the coming winter.
  - In the winter "spill" is lowest as demand is higher, solar is lower, and lakes are being drawn down.
  - In the 100% renewable world there is some shortage, mostly relating to periods of low wind, low hydro and high winter demand.
  - In the limited thermal world gas peakers operate mainly in the winter months to meet peak demands in low wind periods and also to help maintain hydro storages as lakes run down.

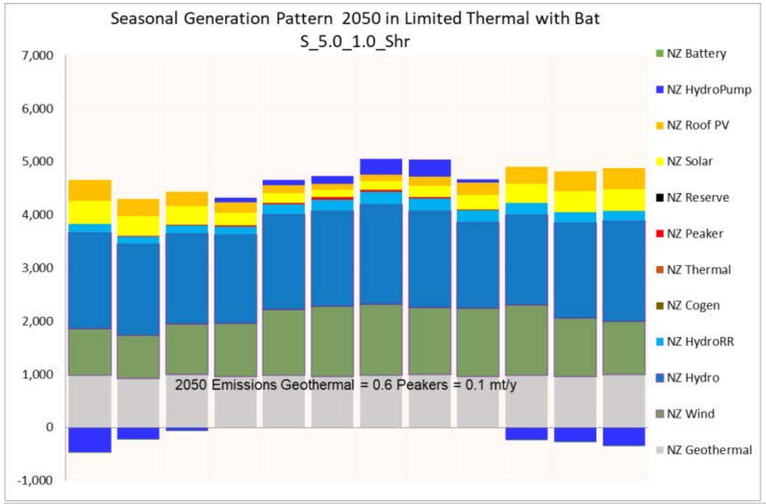


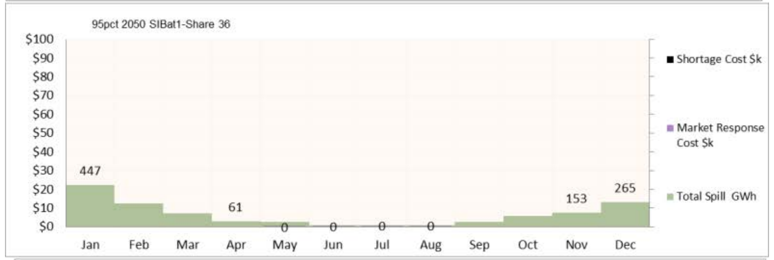


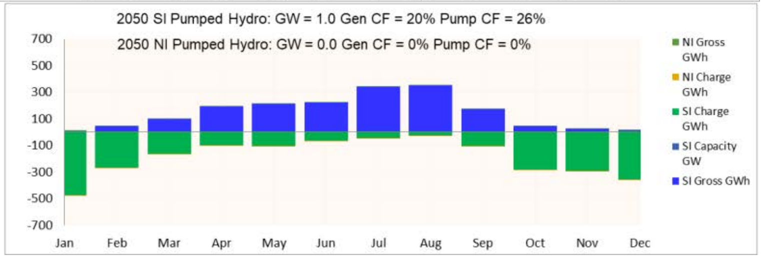
Notes: Shortage cost in the middle chart includes conservation campaigns, rolling cuts and shortage.

Seasonal patterns of operation with SI pumped hydro (5TWh/1GW)

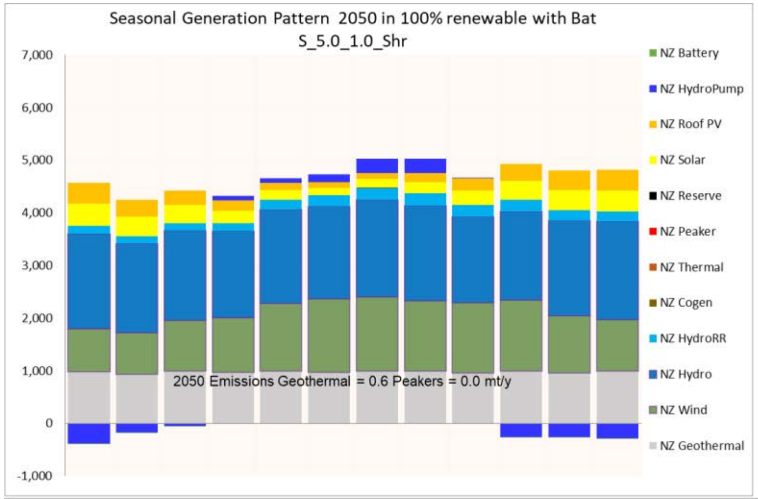
Limited thermal

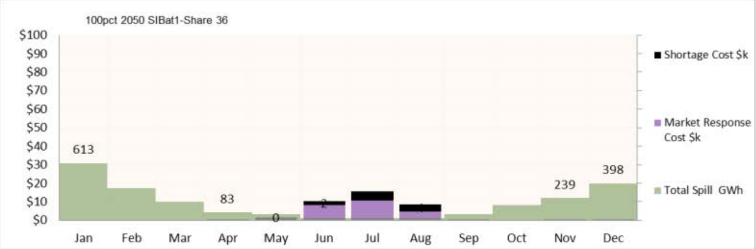


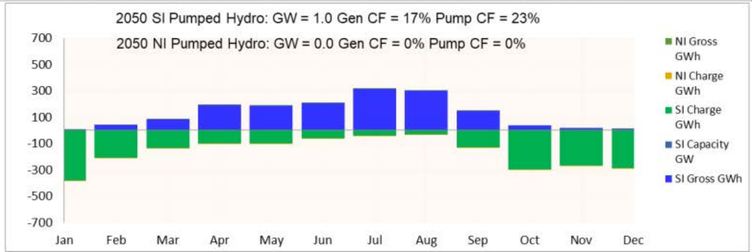




100% renewable

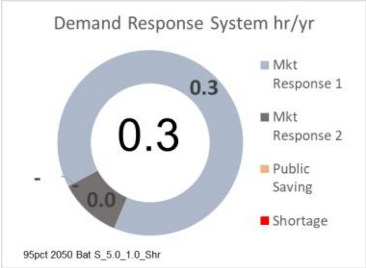


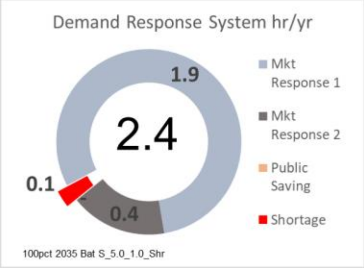




Comments

- A 5TWh/1.0GW SI pumped hydro enables part of the winter peak demand to be met from low cost ‘spill’ energy which is stored from the summer.
- In the Limited thermal world, peak fuel use can be significantly reduced, and there is minimal shortage.
- In the 100% renewable world winter shortages are substantially reduced but not eliminated.
- In both cases there are savings from a reduced level of overbuilding wind/solar/geothermal.
- The pumped storage plant operates in generation mode for most of the winter, and in pumping mode from Nov to Feb when the risk of ‘spill’ is greatest.
- There are some months (Sep-Oct and Mar-May) where there a mix of pumping (eg high wind) and generation (low wind) depending on the state of lakes and residual demand.
- However, the charts show average seasonal etc patterns over many modelled years and the pattern for an individual year can differ from the average

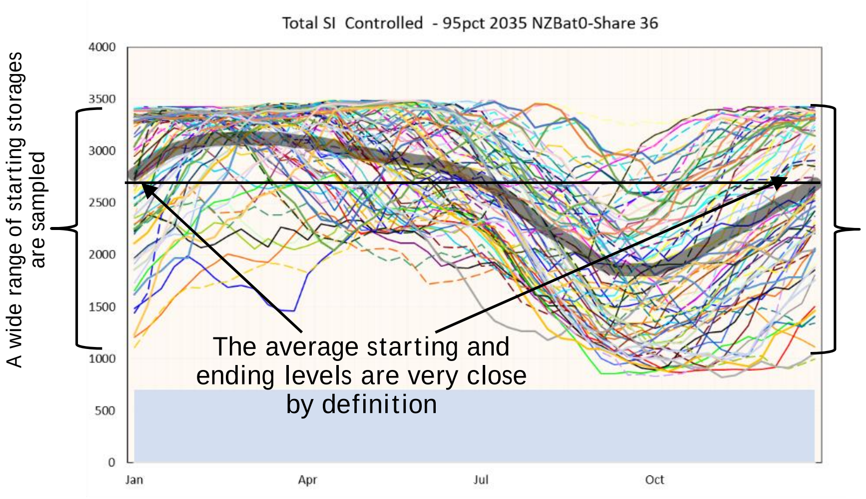


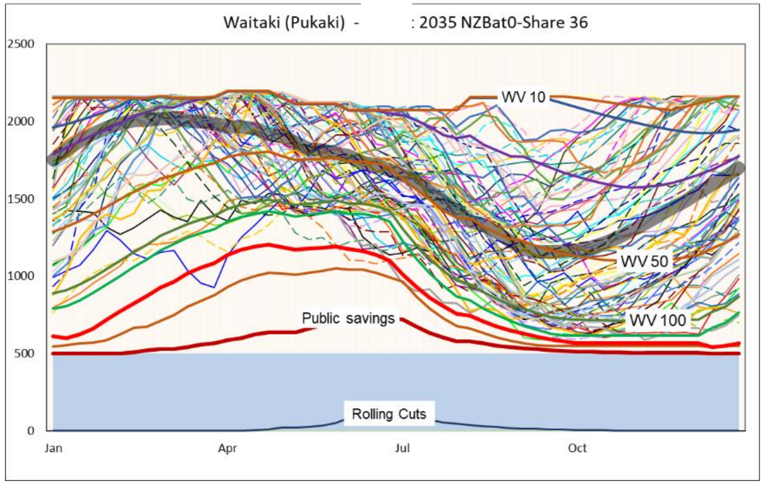


Notes: Shortage cost in the middle chart includes conservation campaigns, rolling cuts and shortage.

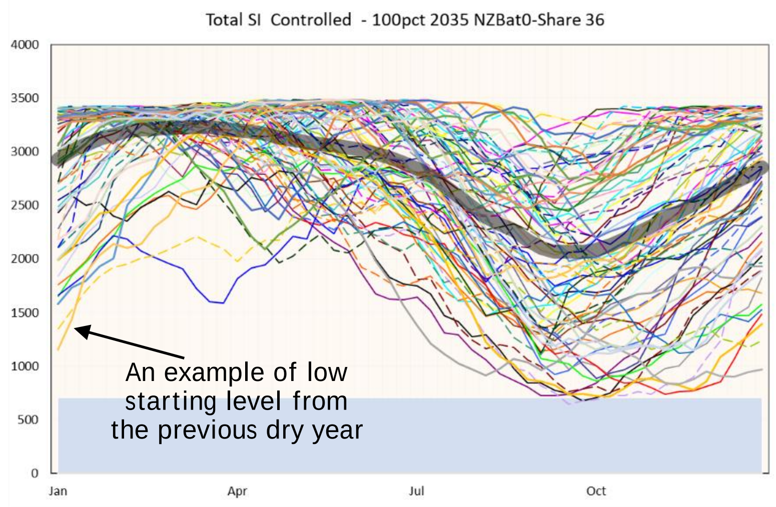
Model is producing sensible looking lake operation in the two different worlds assuming no NZ Battery is available

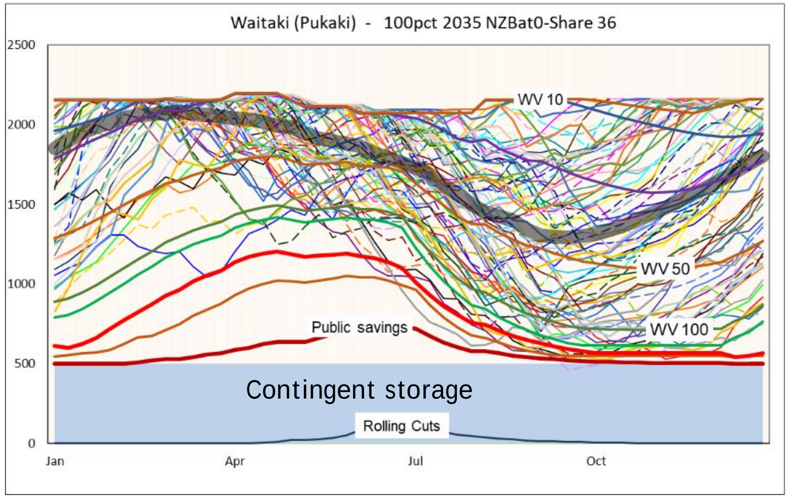
Limited thermal world





100% Renewable (no peaker) world





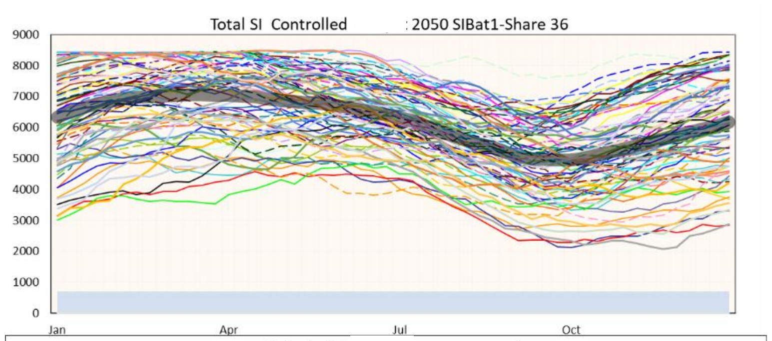
Comments:

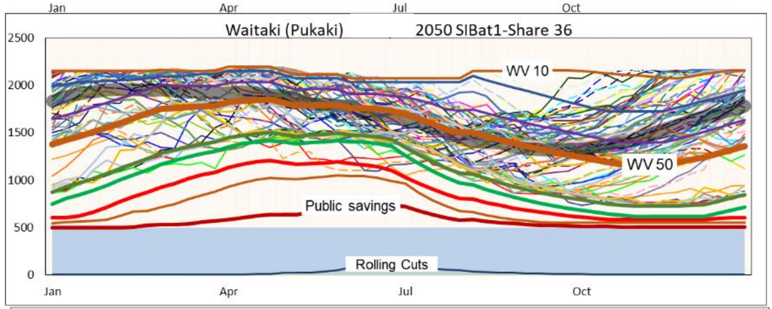
- Lake level (GWh) spaghetti charts are shown for major storage reservoir (Waitaki) and for combined storages in the SI (Waitaki, Tekapo, Clutha).
- The levels includes contingent storage - indicated by the blue zone. The charts shows the result of sequential simulation, so that the end level for each hydro inflow year is used as a starting level for the next hydro inflow year.
  - This enables a full range of inflows and starting level to be explored with a single set of runs. This approach ensures that the average starting and ending storages are very similar, and so avoids the need to adjust the averaged costs for a changes in storage level.
- Note:
  - With overbuilding and no thermal buffer in the 100% Renewable world there is a tendency for the lakes to fill rapidly in Dec to Feb, this has to be countered by reducing the guidelines somewhat otherwise the full storage range would not be used even in the worst hydro sequence.
- Note also:
  - It is assumed that public savings are triggered when the major reservoirs get very close to the contingent zone and rolling cuts are only required when the contingent zone is fully utilised.

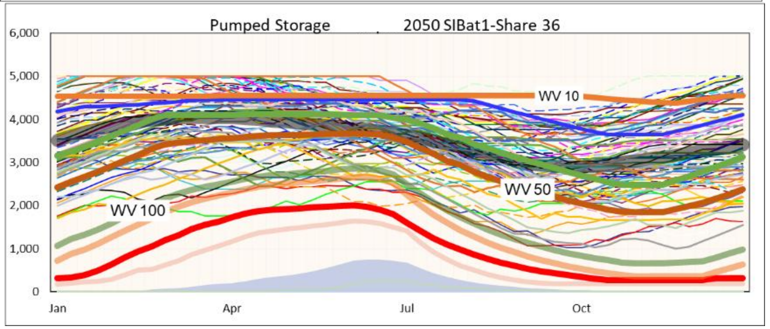
Likewise the model produces sensible looking lake management in the case where NZ Battery is available

Limited thermal world	100% Renewable (no peaker) world	Comments:

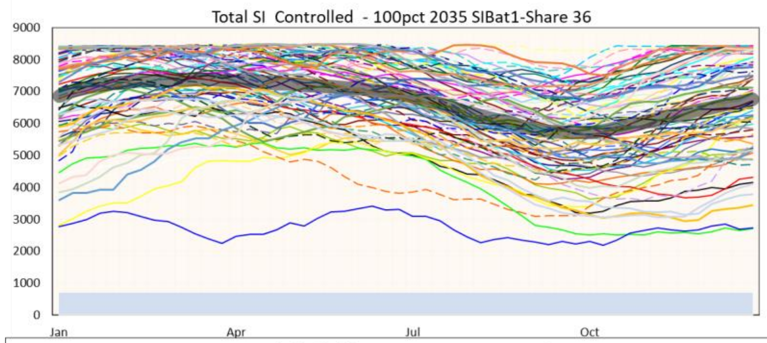
Limited thermal world

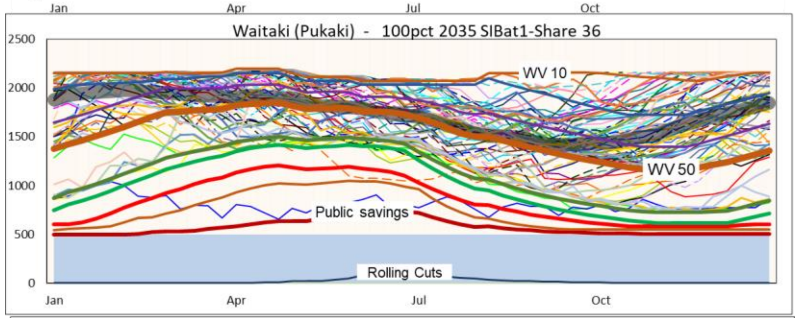


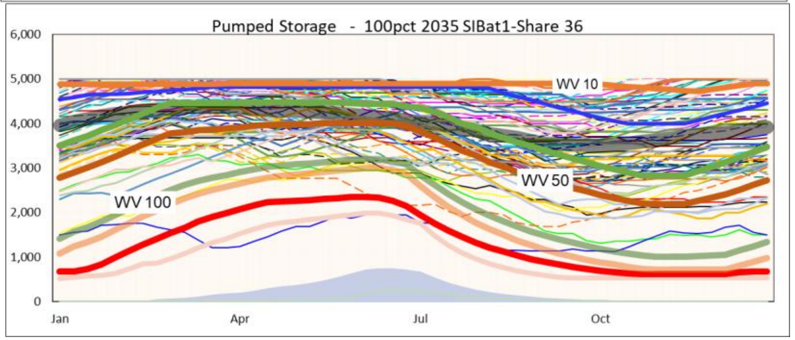




100% Renewable (no peaker) world





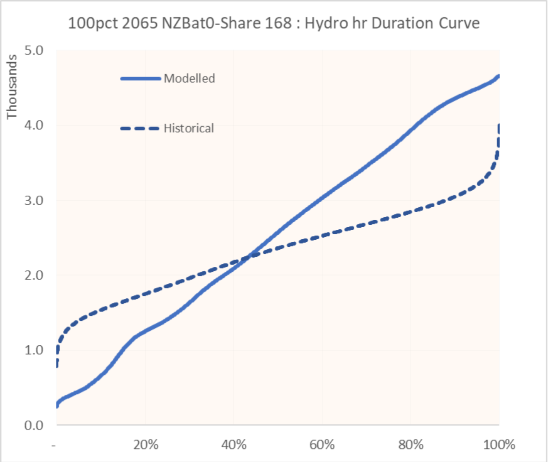


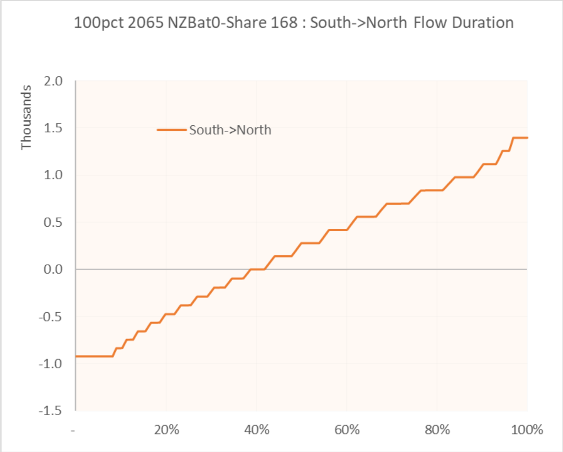
Comments:

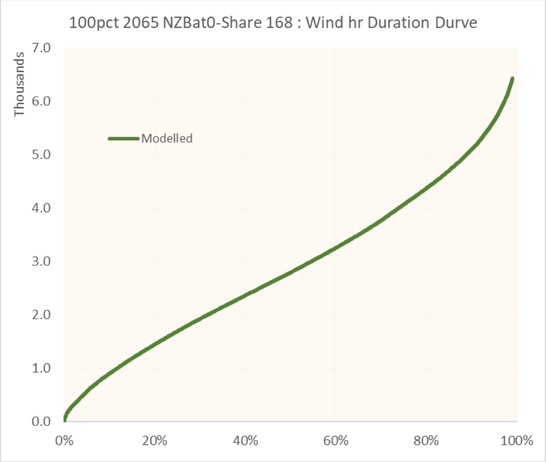
- Lake level (GWh) spaghetti charts are shown for a major storage reservoir (Waitaki) and the sum of the controlled lakes in the SI (Waitaki, Tekapo, Clutha) and for NZ Battery.
- As before, the level includes contingent storage - indicated by the blue zone. The charts shows the result of sequential simulation, so that the end level for each hydro inflow year is used as a starting level for the next hydro inflow year.
- Note:
  - With overbuilding and no thermal buffer in the 100% Renewable world there is a tendency for the lakes to fill rapidly in Dec to Feb, this has to be countered by reducing the guidelines somewhat otherwise the full storage range would not be used even in the worst hydro sequence.
- Note also:
  - It is assumed that public savings are triggered when the major reservoirs get very close to the contingent zone and rolling cuts are only required when the contingent zone is fully utilised.

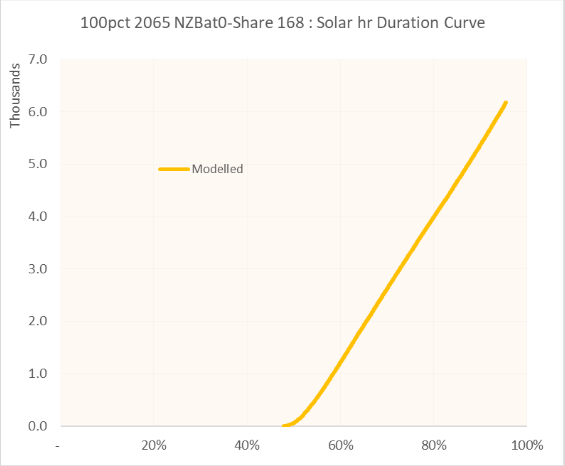
Generation duration curves in 2065

No NZ Battery 100%

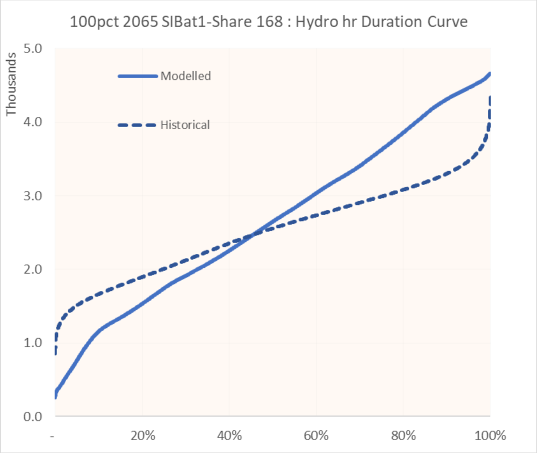


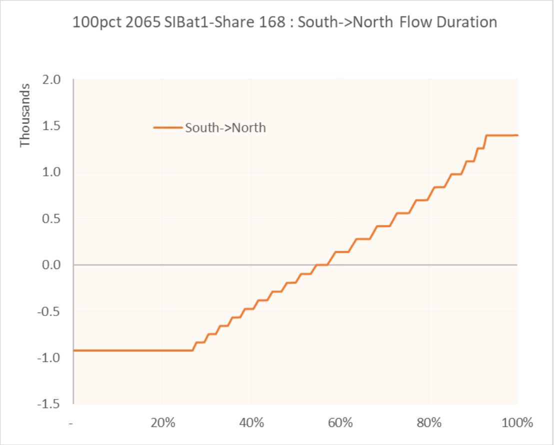


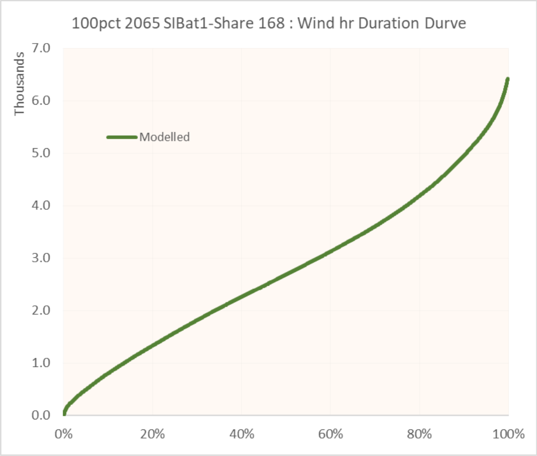


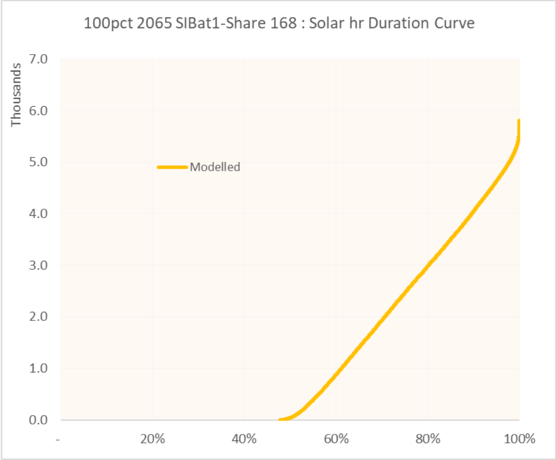


With 5TWh/1.0 GW Battery in South Island





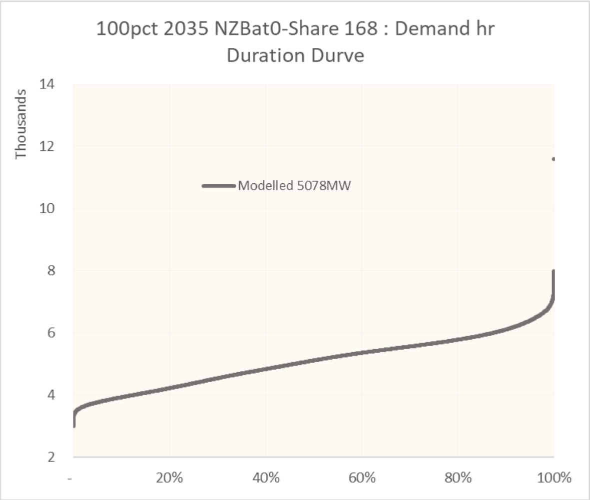




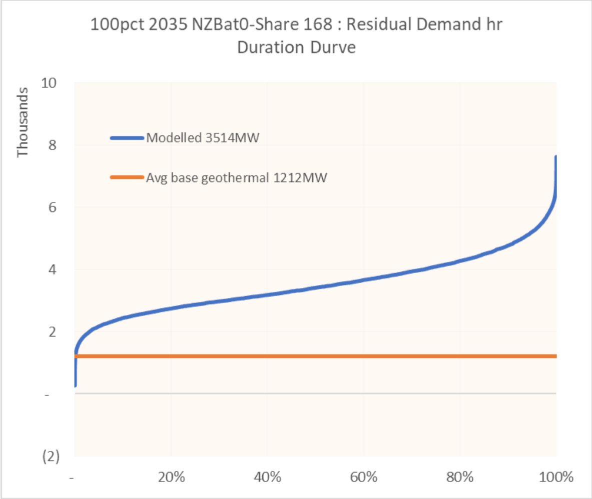
Modelled generation patterns for wind, and solar are similar for the NZ Battery ‘in’ and ‘out’ cases and this appears reasonable given underlying physics. However, modelled operation of existing hydro generation changes to be more flexible than historical patterns in both the NZ Battery ‘in’ and ‘out’ cases. This change reflects the growing need for hydro to offset short term intermittency. It is unclear whether the existing hydro system will be physically able to fully alter its operation. To the extent it encounters physical constraints, we expect that would bring forward in time the gross benefits provided by the different NZ Battery options - but we don’t expect any material change to relative benefits of different tank/tap options

Load and Residual Load Duration Curves in 2065 - 100% renewables (no peakers)

No Battery - 2035



100pct 2035 NZBat0-Share 168 : Demand hr Duration Durve

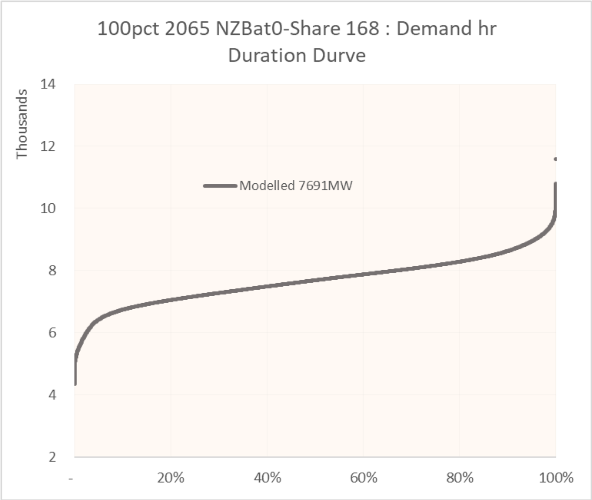


100pct 2035 NZBat0-Share 168 : Residual Demand hr Duration Durve

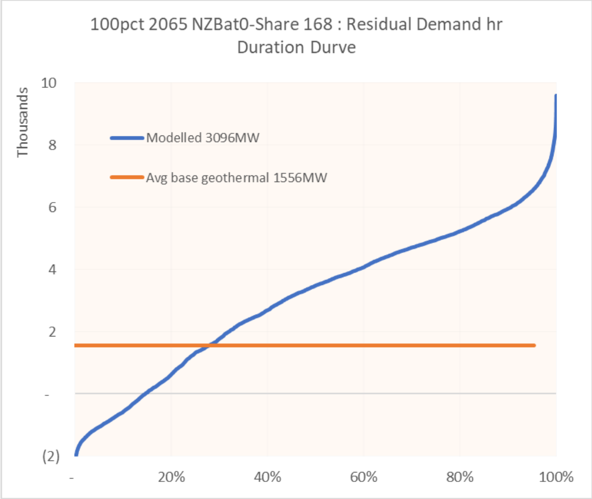
Between 2035 and 2065 the demand duration curve rises and flattens as EV & PH load is added…

and the residual demand curve steepens as more wind and solar is built. The peak residual demand remains high & risk of spill increases as RLDC falls below base geothermal generation

No Battery - 2065



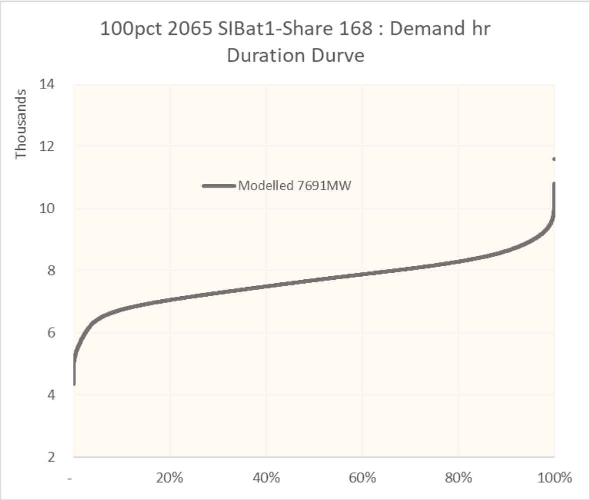
100pct 2065 NZBat0-Share 168 : Demand hr Duration Durve



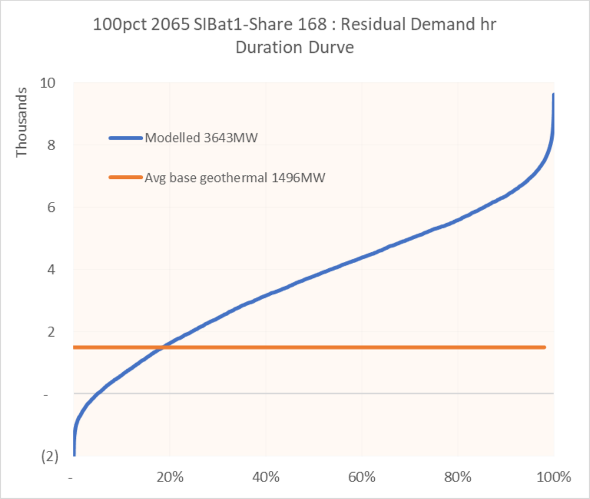
100pct 2065 NZBat0-Share 168 : Residual Demand hr Duration Durve

Adding NZ Battery lifts the residual demand curve rises as some wind and solar build can be avoided when pumped storage is added. The risk of spill reduces.

South Island Battery 5TWh/1.0 - 2065



100pct 2065 SIBat1-Share 168 : Demand hr Duration Durve



100pct 2065 SIBat1-Share 168 : Residual Demand hr Duration Durve

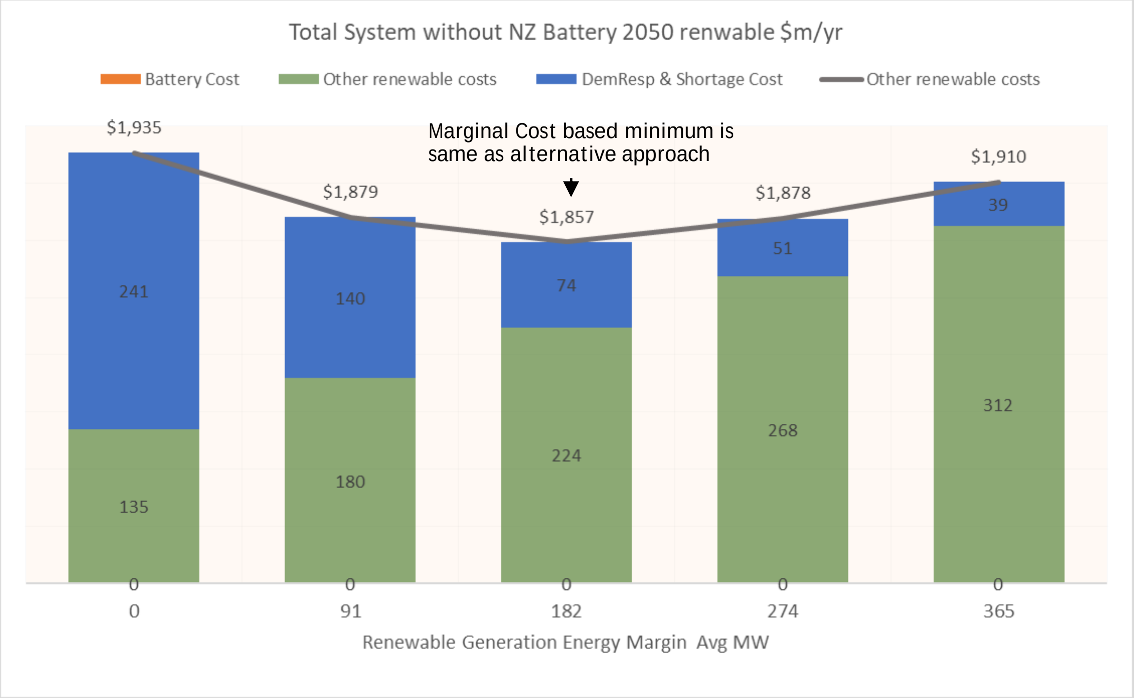
Notes: Residual Demand is demand minus potential generation from solar and wind generation. This measure highlights the risk of "spill" as the RLDC falls below minimum levels of other generation. The chart shows baseload geothermal, but there is also minimum hydro generation from resource constraints and hydro tributaries which will also contribute to the risk of "spill".

We have confirmed that the 'planting optimisation' part of the modelling process is robust

concept consulting

JC²

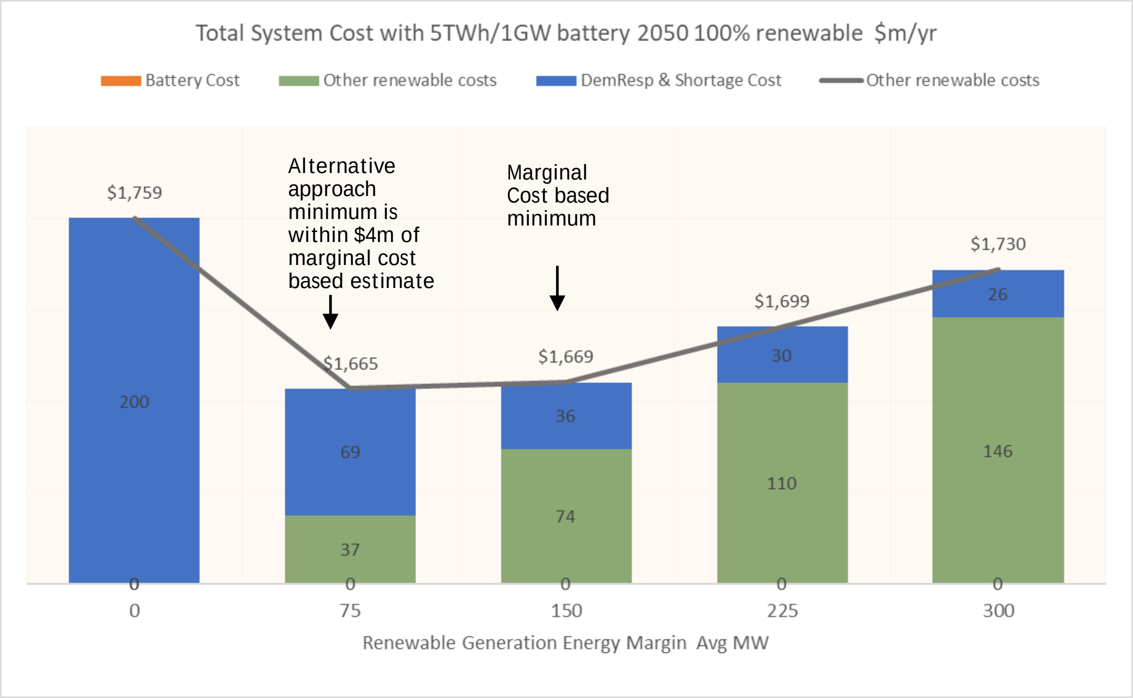
Without NZ Battery the min system cost is $1857m/y in 2050



The marginal cost based minimum is consistent with minimum from curve with increments from minus 10% to plus 10% increase in average MW from new renewables (using shares from price based revenue adequate case) but no changes to little batteries.

Marginal cost based - adds a mix of new batteries, geothermal, wind and solar until they are just revenue adequate with "water value" and shortage based marginal pricing.

With NZ Battery 5.0TWh/1.0GW - the minimum drops $188-192M to $1665-1669m

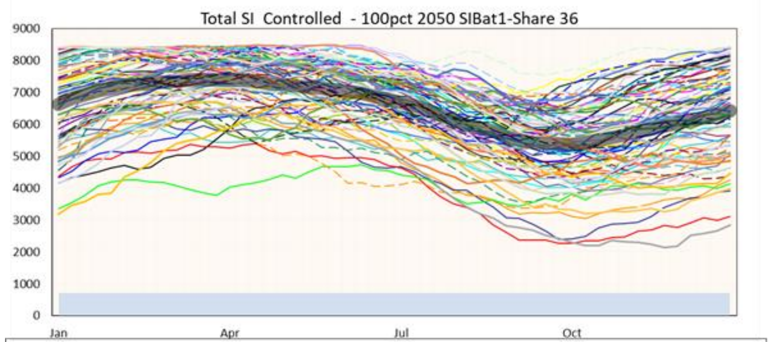


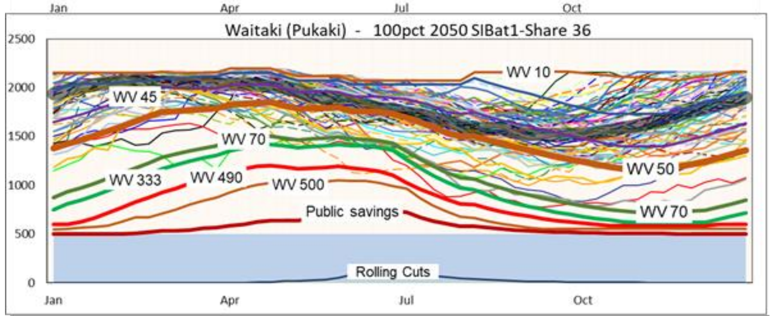
The marginal cost based minimum is slightly higher system cost from total system cost approach - but highly dependent on shortage costs (very sensitive to modelling) .

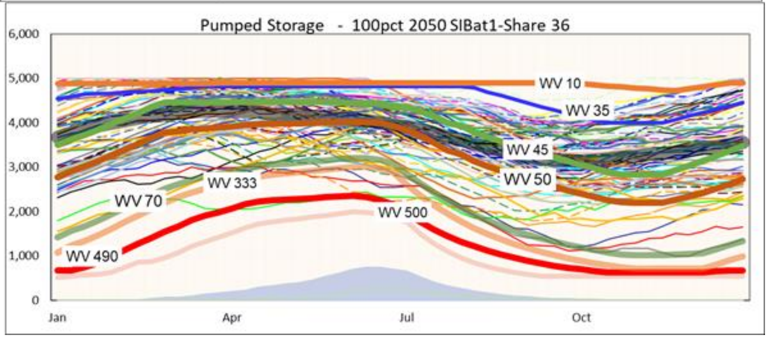
The system benefit using price based minimums is $188m/y, compared with $192m/y using the minimums of total system cost.

Outcomes are similar with different South Island pumped hydro guidelines

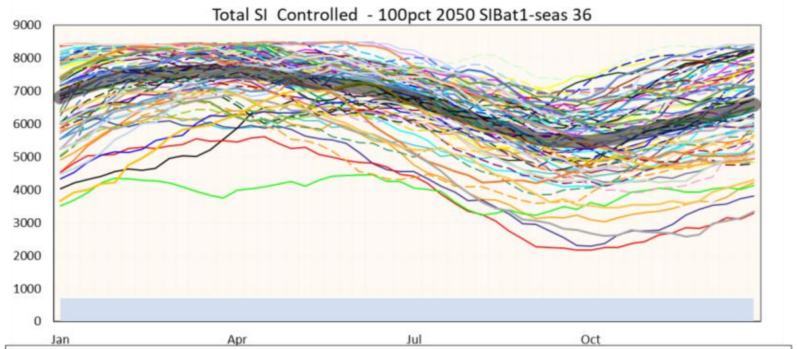
Shared water value - scheduled by time zone

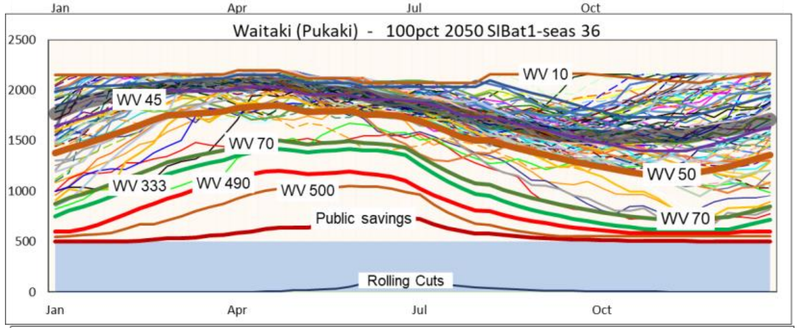


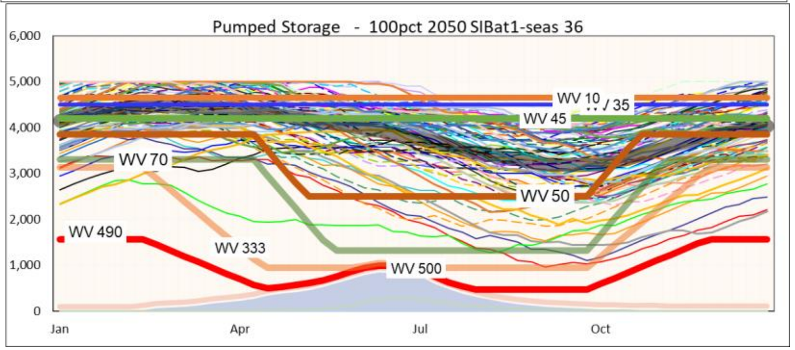




SI Pumped Hydro Flat seasonal guidelines







Comments

- We have tested out the sensitivity of the results to different assumed Pumped hydro operational rules.
- We looked at a "shared" water value approach similar to that being used by Energy Link. This assumes that the operation of the pumped hydro is operated in a similar fashion to the other major hydro reservoirs.
- The alternative approach assumes a set of winter and summer guidelines which drive the pumped storage to fill during the periods of high 'spill' risk and then run down as required during the winter.
- This approach can incorporate additional buffer levels to ensure the pumped storage has sufficient headroom to absorb 'spill', and well as minimum zones to ensure supply in the worst inflow scenarios (including pairs of dry years if necessary).
- The charts show that either approach gives a similar overall result.

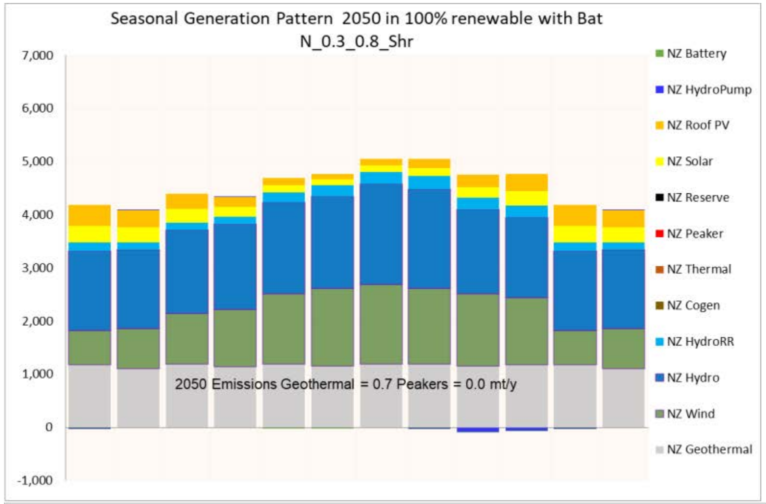
Detailed results for options in the North Island

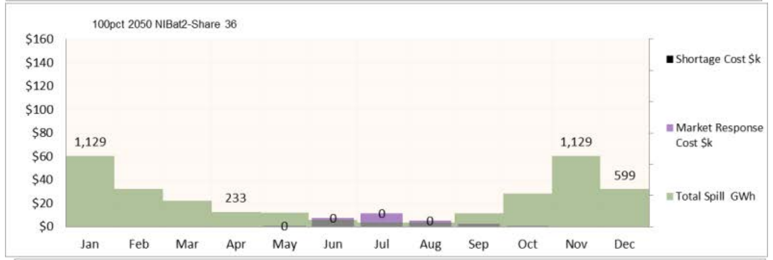
This section takes a deeper dive on North Island options

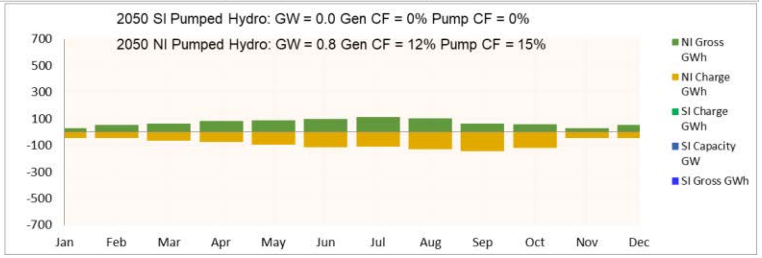
- This section takes a more in-depth look at North Island options
- The choice of options is somewhat arbitrary because we have no information on technical feasibility or costs
- Given the uncertainties, we have chosen to examine options with varying levels of storage (0.3 to 1.0 TWh) and 0.8 GW of capacity

Seasonal operation with NI pumped hydro

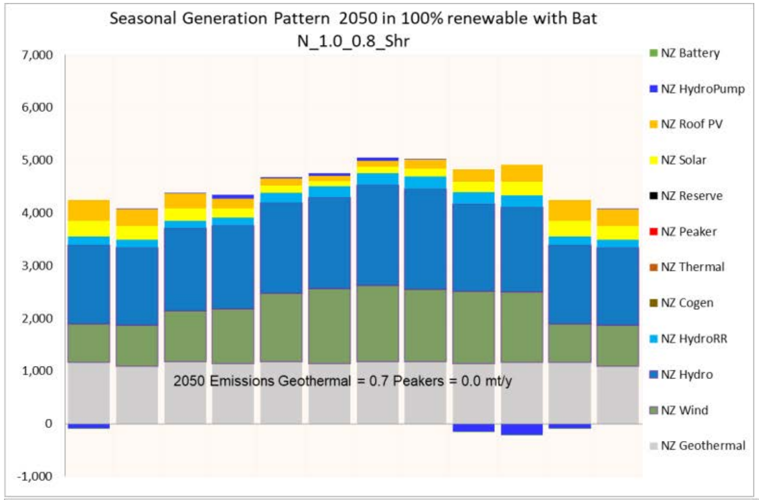
100% renewable 0.3TWh/0.8GW - 2 week storage

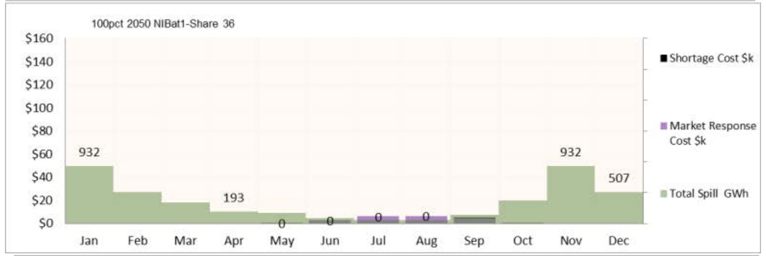


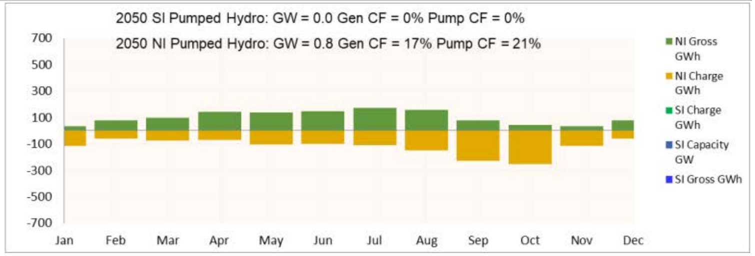




100% renewable 1.0TWh/0.8GW - 7 weeks

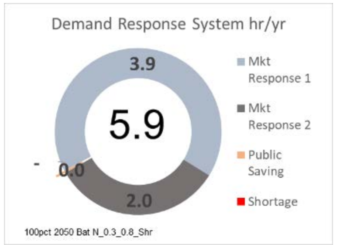


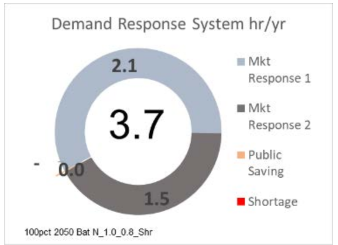




Comments

- NI pumped storage is assumed to have much less storage capacity than the SI options.
- This means that its operation would deal with fluctuations in renewable supply with each day and month.
- Both NI options enable savings in small-scale battery costs and achieve reductions in shortages arising from sustained periods of low renewable demand which are not able to be accommodated by the hydro system.
- The 1 TWh storage scheme would provide some limited seasonal shifting but mostly these NI pumped hydro options respond to periods of relatively high or low intermittent supply throughout the year.
- The greatest value is from avoiding peak shortage during sustained periods of low wind during the winter.

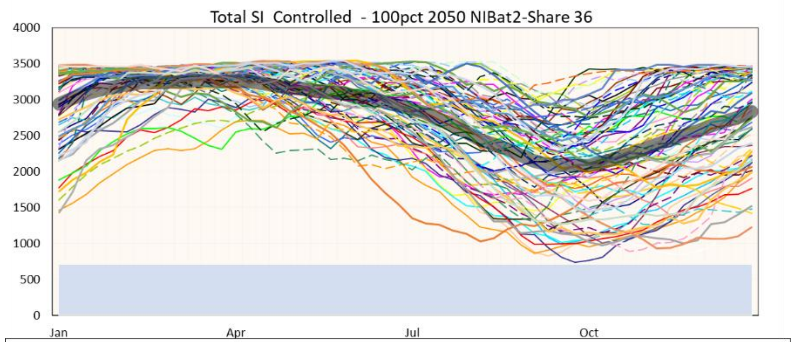


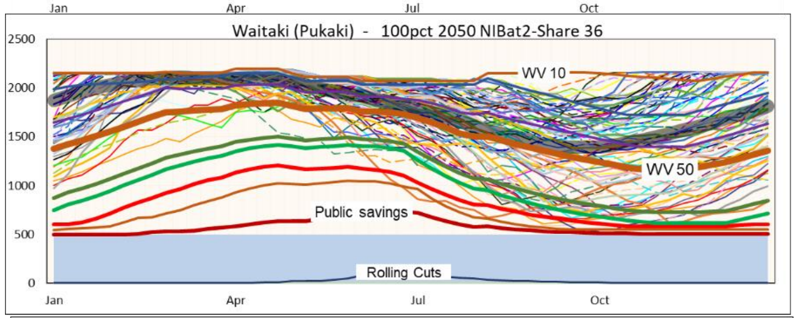


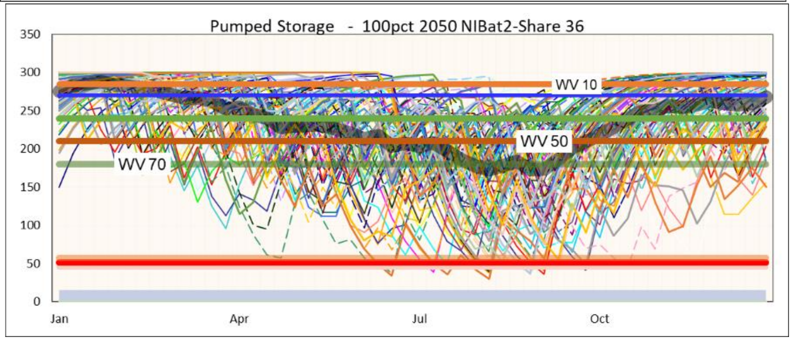
Notes: Shortage cost in the middle chart includes conservation campaigns, rolling cuts and shortage.

NI Pumped storage operation

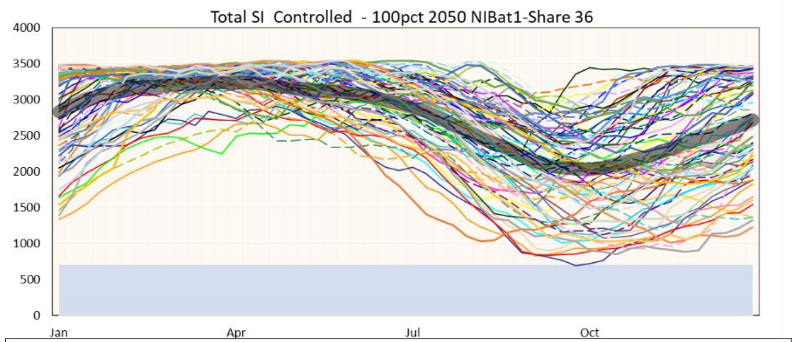
100% renewable 0.3TWh/0.8GW - 2 week storage

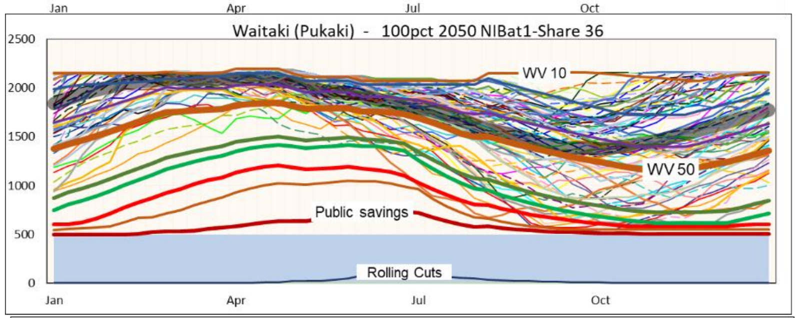


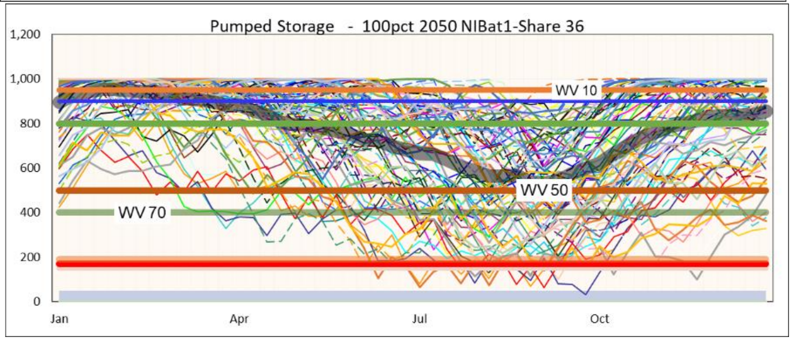




100% renewable 1.0TWh/0.8GW - 7weeks





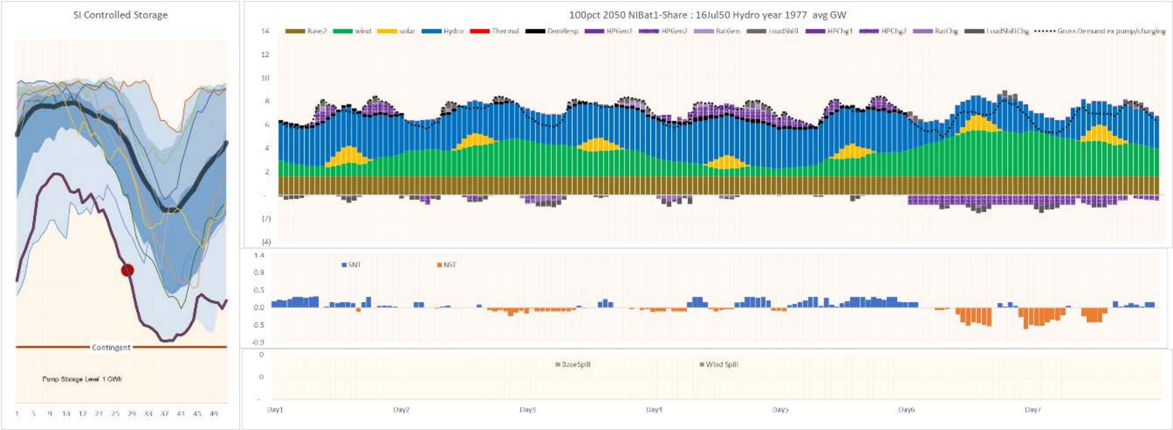


Comments

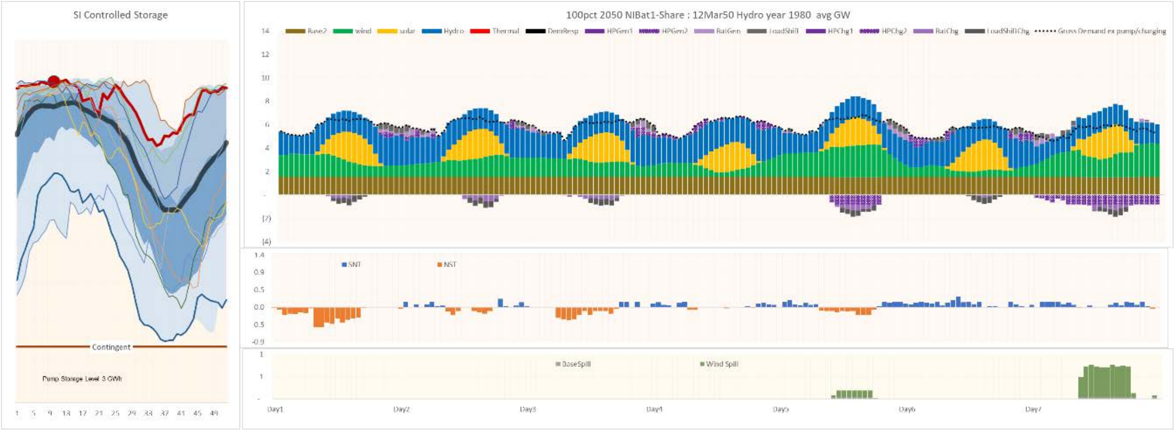
- Total SI controlled storage is not significantly affected by increasing size of the NI pumped storage
- Put another way, existing SI storage would continue to provide most of the intra-year seasonal flexibility
- Note that the modelling of NI pumped storage scheduling is based on the levels in storage at the start of each model period and tends to be rather “bang bang” particularly for the NI option with 0.3TWh.
- In reality this would be offered in tranches on a daily or shorter interval and so the storage trajectories will be somewhat smoother
- Having said that, we do not think it would materially affect the estimated benefits.

Illustrative weekly schedules for NI Pumped Storage in 2050 (100% renewable - no peakers) appear reasonable

Winter and Summer 1.0TWh NI scheme

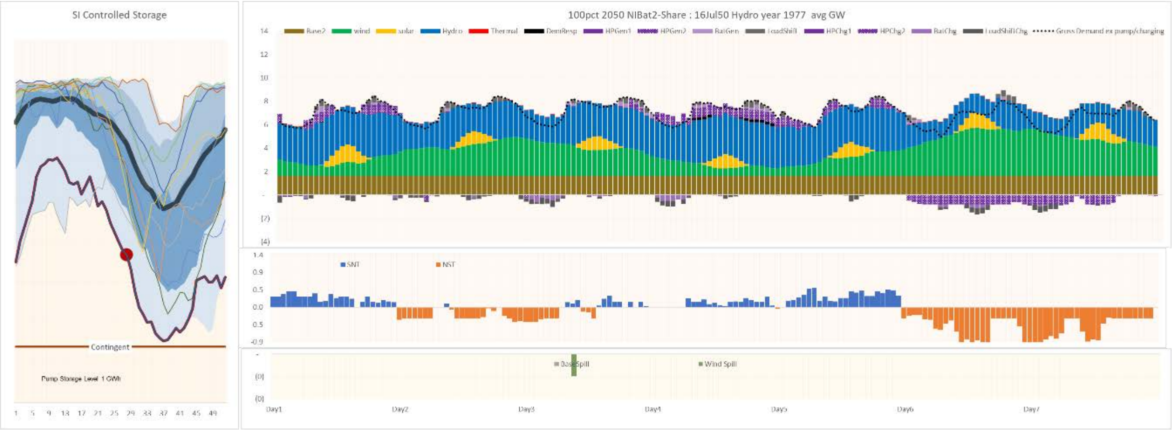


Winter - dry year

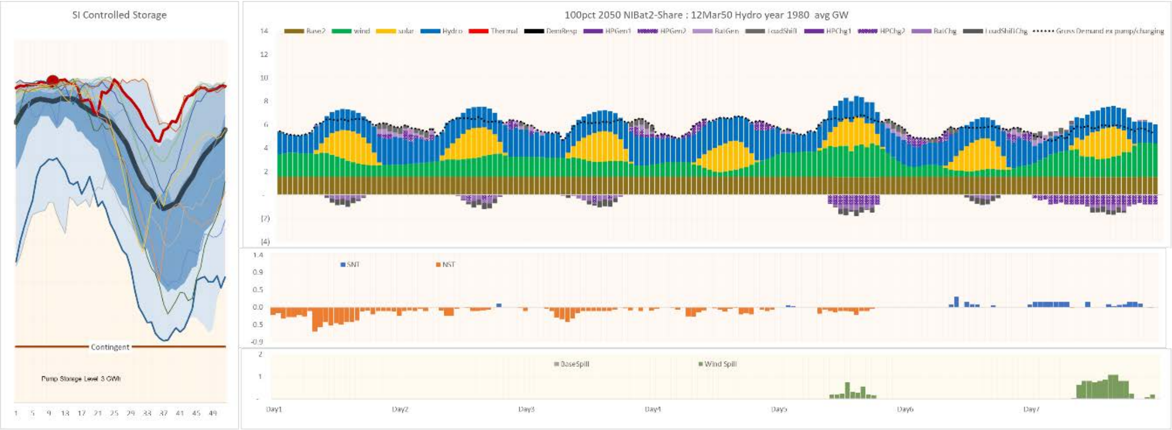


Summer - full lakes

Winter and Summer 0.3TWh NI scheme



Winter - dry year



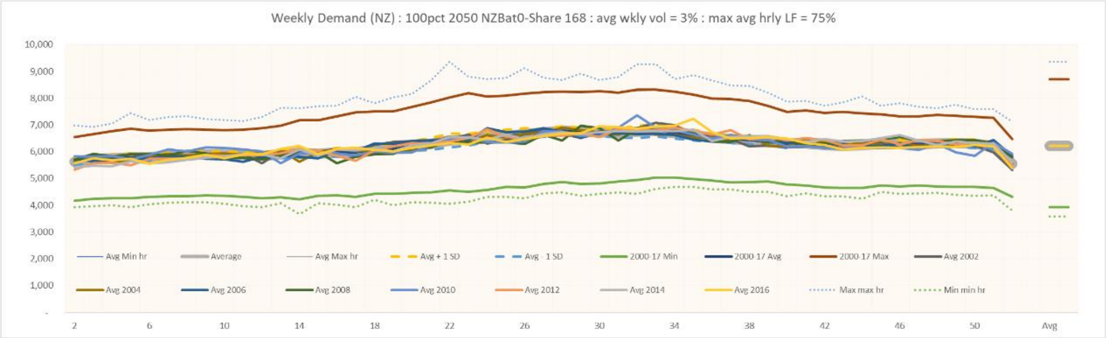
Summer - full lakes

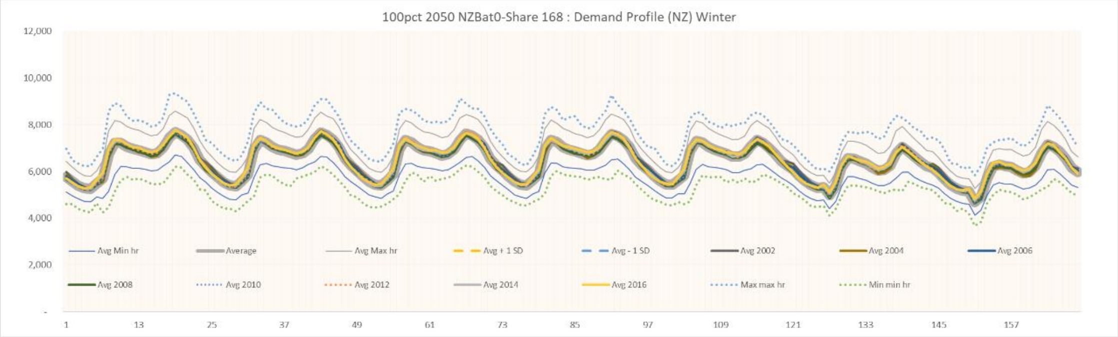
Notes: Note that these charts are for an illustrative modelled week in the summer and winter. The final results average the results over 86 separate weather based supply (hydro/wind/solar/demand) cases and 52 weeks over the year.

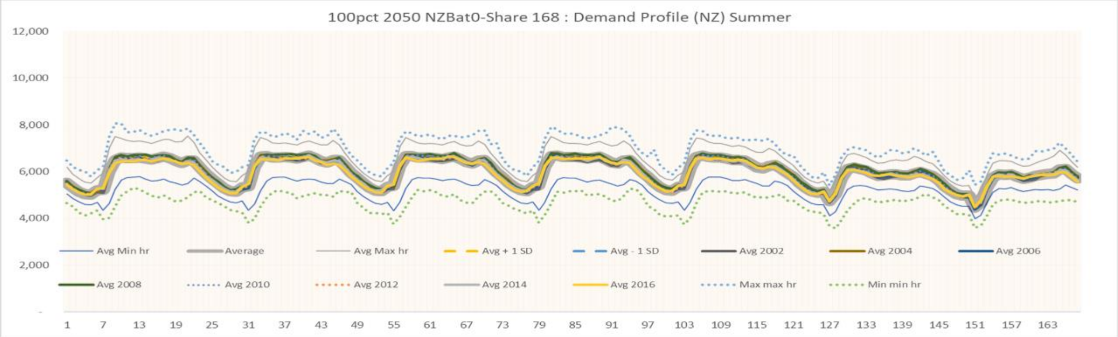
APPENDIX 1: DETAILED INPUTS :
DEMAND, HYDRO, WIND, AND SOLAR SUPPLY PROFILES AND STATISTICS

Demand Inputs

The demand has significant seasonal and within day shape



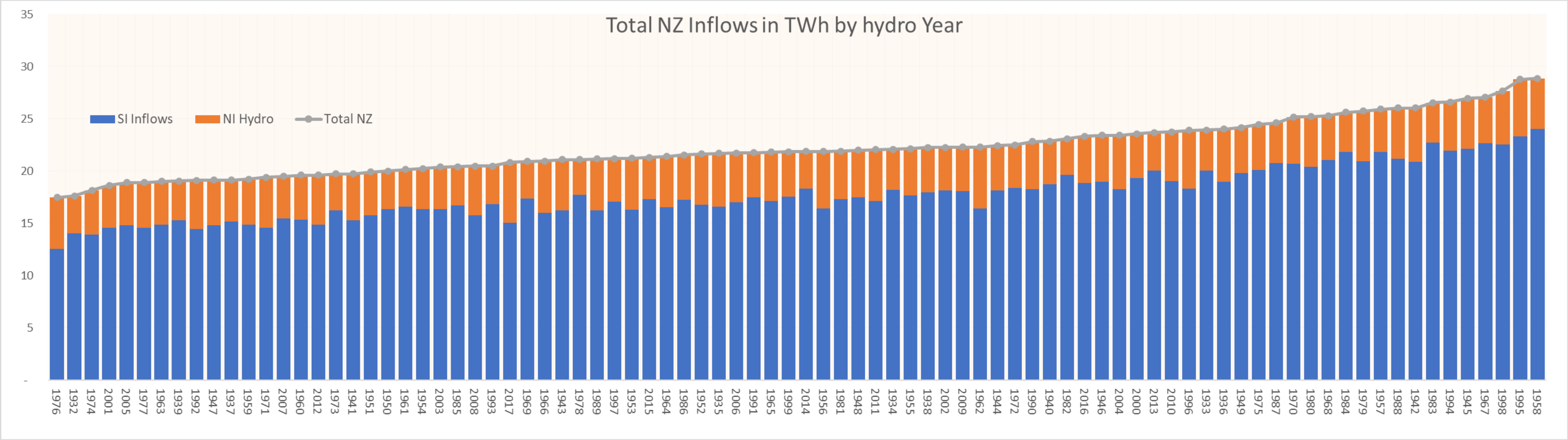


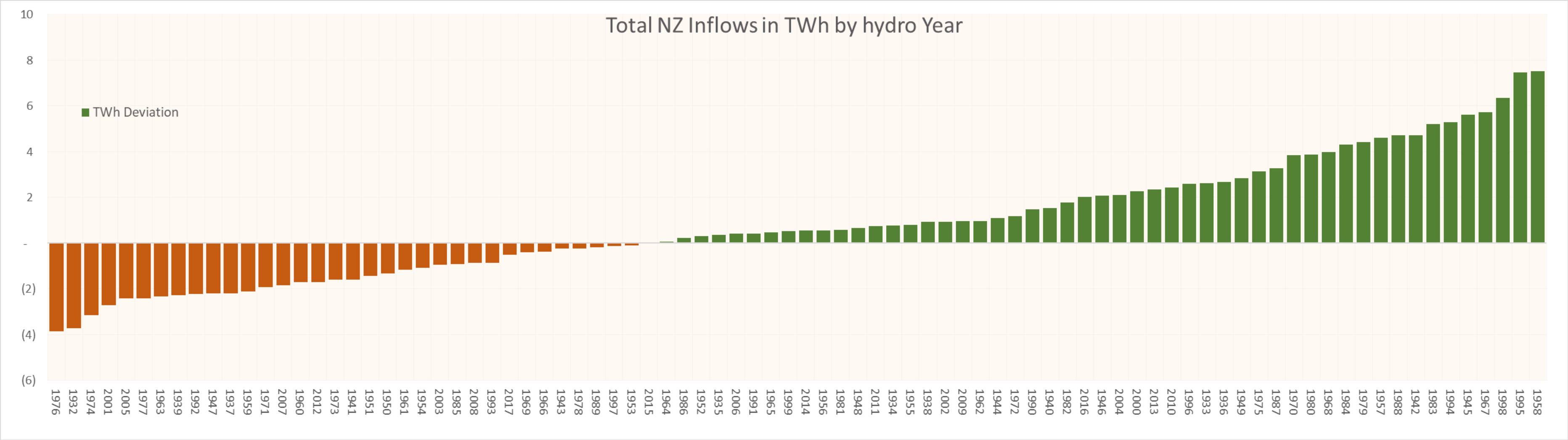


Comments

- These charts show the ranges of variation and patterns of demand, solar and wind used in the modelling.
- A full set of 18 years of hourly matched demand, wind and solar data is used in the modelling.
- This ensures that corelations between intermittent supply and demand are preserved and are accounted for in the modelling, along with weekly hydro tributary and controllable inflow variations. This becomes very important once the system has much higher levels of wind and solar a less flexible thermal back up.

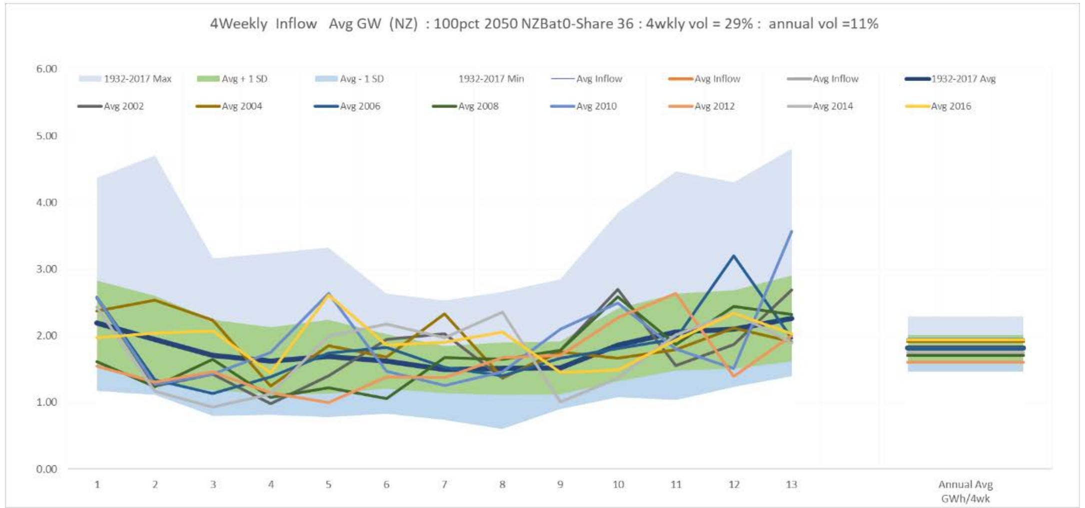
Annual distribution of hydro inflows by island

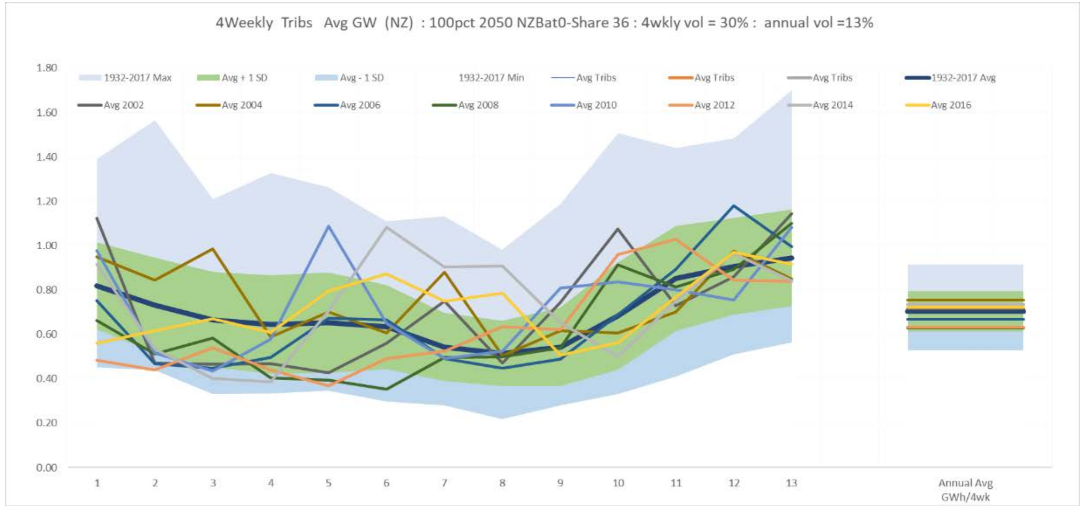




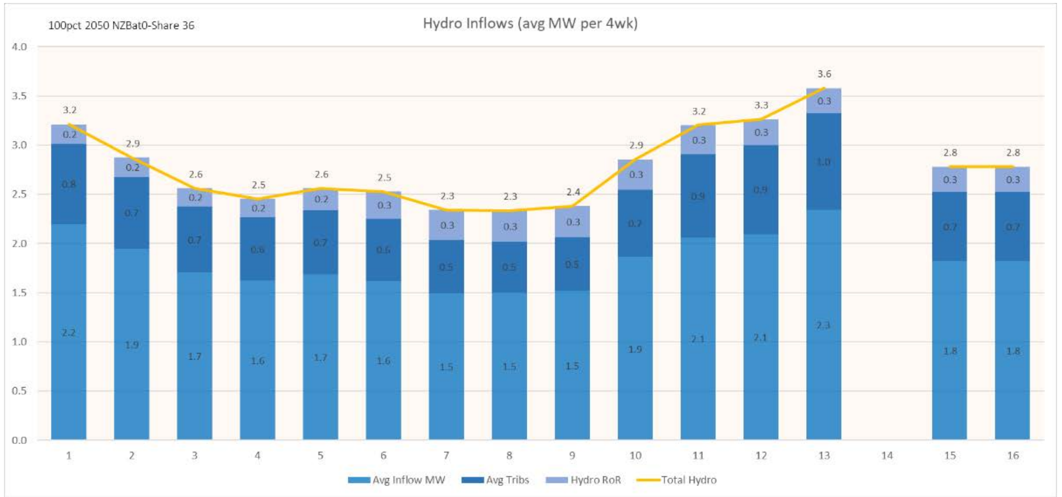
The seasonal patterns of hydro and other renewables in 2050

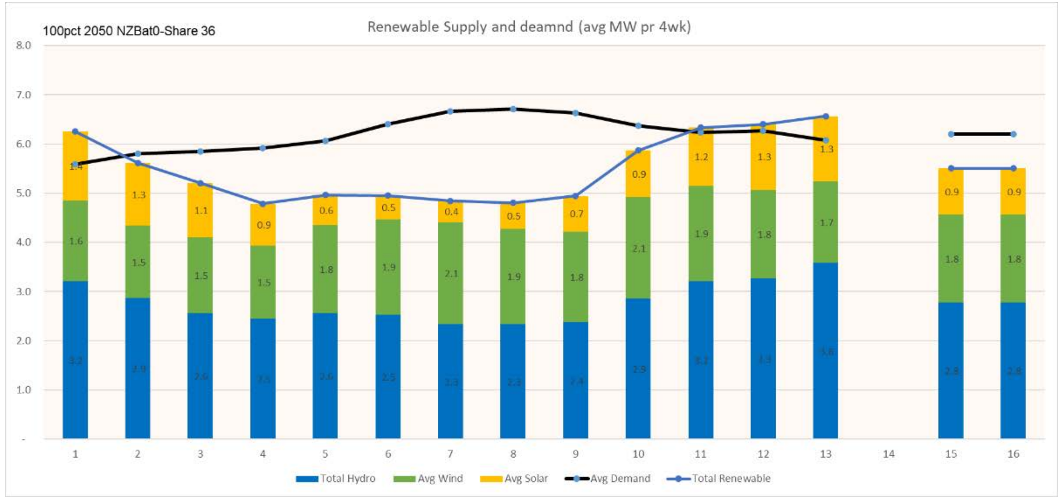
There is a high volatility in hydro inflows per month





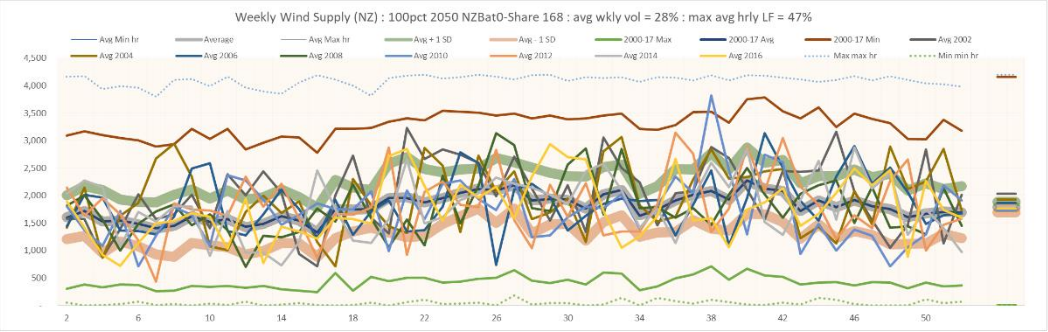
Hydro Inflows and solar supply are lowest during winter

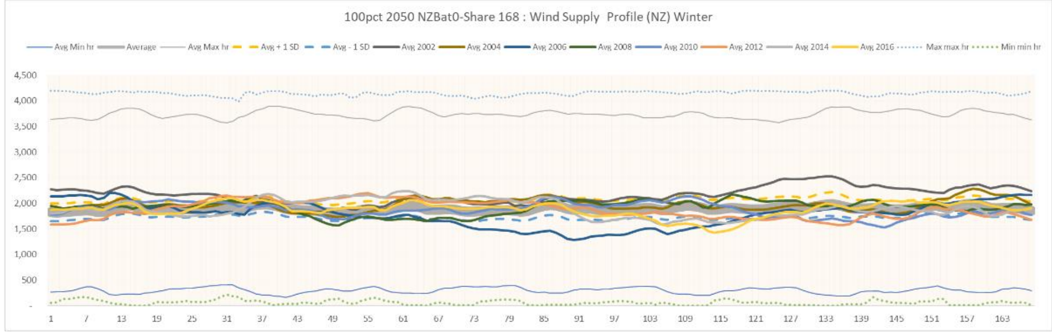


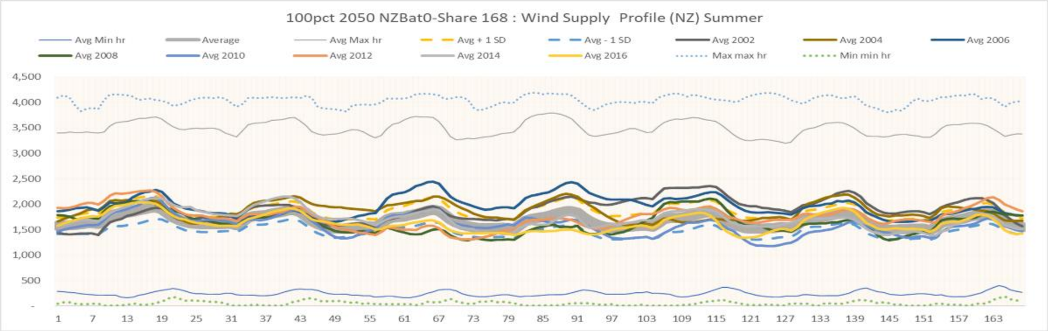


Solar and Wind Supply Data

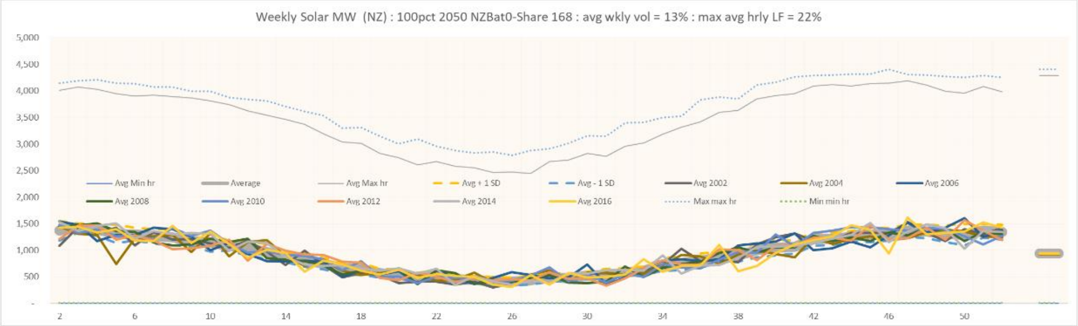
Wind

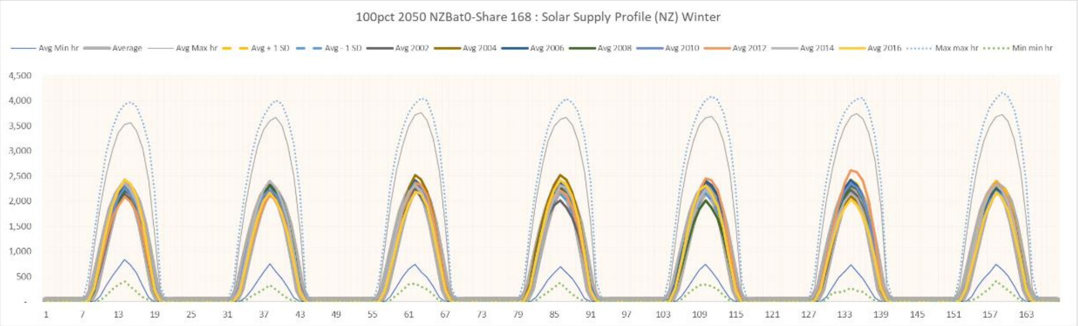


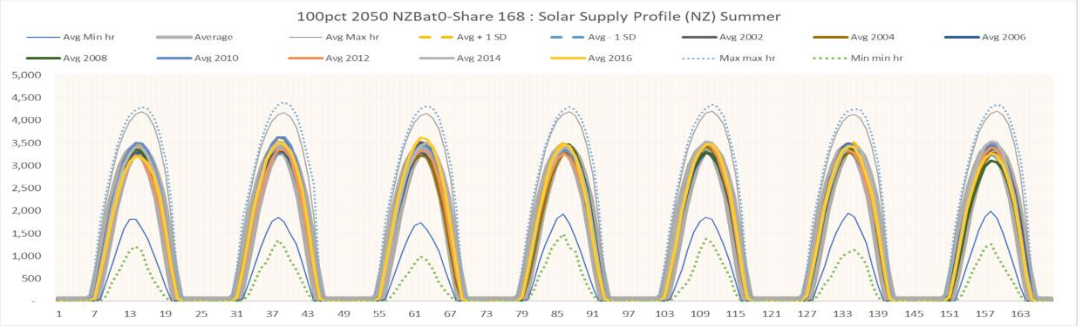




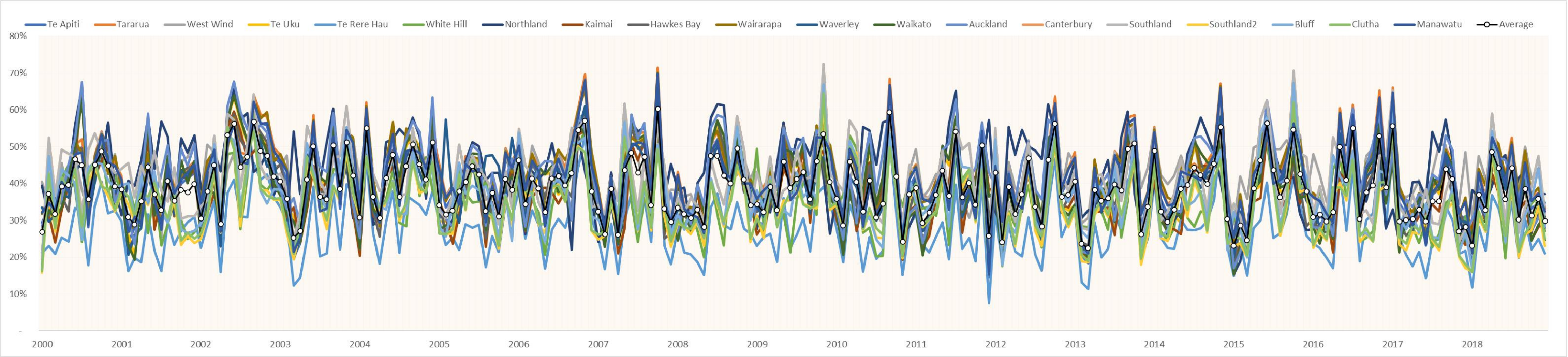
Solar







There is high monthly variation in wind supply by region as shown by the monthly chart over 18 years. Statistical measures of variation on other time frames are provided below.



Daily Statistics

	Average Capacity factor	P5	P10	P90	P95	Volatility	Cross Correl Tararua	Serial Correl
Te Apiti	40%	90%	83%	15%	5%	70%	100%	51%
Tararua	43%	91%	84%	18%	8%	65%	100%	50%
West Wind	43%	90%	83%	18%	7%	65%	77%	37%
Te Uku	39%	86%	79%	14%	5%	70%	59%	54%
Te Rere Hau	28%	74%	65%	8%	2%	84%	98%	51%
White Hill	36%	85%	78%	10%	4%	77%	43%	55%
Northland	42%	91%	84%	16%	5%	68%	23%	55%
Kaimai	37%	84%	76%	14%	6%	70%	58%	54%
Hawkes Bay	39%	90%	81%	15%	9%	69%	81%	52%
Wairarapa	43%	90%	83%	19%	8%	64%	97%	47%
Waverley	39%	85%	77%	16%	6%	67%	85%	48%
Waikato	39%	88%	80%	13%	5%	71%	61%	53%
Auckland	42%	90%	84%	15%	5%	69%	52%	55%
Canterbury	41%	90%	83%	16%	7%	67%	47%	57%
Southland	41%	90%	83%	16%	7%	67%	47%	57%
Southland2	34%	83%	74%	11%	4%	76%	52%	55%
Bluff	37%	85%	76%	13%	4%	73%	45%	58%
Clutha	35%	83%	74%	13%	5%	73%	50%	56%
Average	39%	87%	79%	15%	6%	**70%**	65%	52%

70% daily volatility

Monthly Statistics

	Max	P10	P90	Min	Volatility	Cross Correl Tararua	Serial Correl
Te Apiti	70%	53%	28%	15%	26%	100%	13%
Tararua	72%	55%	31%	17%	23%	100%	12%
West Wind	64%	53%	33%	22%	19%	86%	6%
Te Uku	63%	53%	26%	17%	26%	77%	30%
Te Rere Hau	57%	40%	18%	8%	31%	99%	10%
White Hill	62%	49%	24%	17%	27%	64%	8%
Northland	66%	57%	28%	15%	24%	41%	42%
Kaimai	66%	51%	26%	16%	25%	78%	25%
Hawkes Bay	67%	52%	26%	16%	25%	89%	20%
Wairarapa	70%	55%	31%	20%	23%	99%	12%
Waverley	66%	51%	28%	19%	24%	90%	13%
Waikato	64%	53%	27%	15%	26%	77%	31%
Auckland	68%	56%	28%	17%	25%	73%	33%
Canterbury	72%	55%	30%	19%	23%	67%	9%
Southland	72%	55%	30%	19%	23%	67%	9%
Southland2	62%	47%	23%	16%	27%	72%	14%
Bluff	67%	51%	26%	17%	26%	64%	8%
Clutha	65%	47%	25%	16%	25%	70%	13%
Average	66%	52%	27%	17%	**25%**	78%	17%

25% monthly volatility

Annual Statistics

	Max	P10	P90	Min	Volatility	Cross Correl Tararua
Te Apiti	47%	44%	37%	36%	7%	100%
Tararua	50%	47%	40%	39%	7%	100%
West Wind	47%	46%	39%	39%	6%	83%
Te Uku	46%	41%	35%	35%	8%	79%
Te Rere Hau	34%	32%	25%	25%	9%	99%
White Hill	40%	39%	33%	31%	7%	78%
Northland	48%	46%	39%	37%	7%	22%
Kaimai	44%	40%	34%	33%	7%	73%
Hawkes Bay	46%	43%	36%	35%	8%	89%
Wairarapa	49%	47%	40%	38%	7%	99%
Waverley	45%	42%	36%	35%	7%	87%
Waikato	46%	42%	35%	35%	7%	81%
Auckland	49%	44%	38%	37%	7%	72%
Canterbury	46%	45%	39%	36%	7%	76%
Southland	46%	45%	39%	36%	7%	76%
Southland2	39%	38%	30%	28%	9%	75%
Bluff	41%	41%	34%	32%	7%	74%
Clutha	40%	38%	31%	29%	8%	74%
Average	45%	42%	36%	34%	**7%**	80%

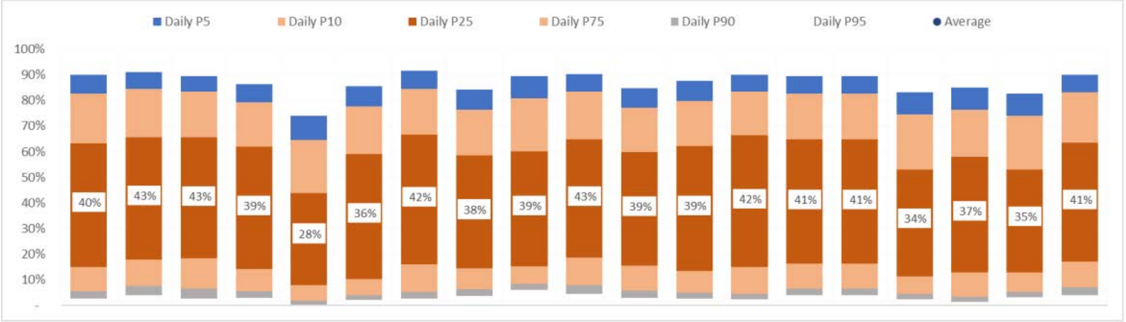
7% annual volatility

Note: Volatility = standard deviation/mean

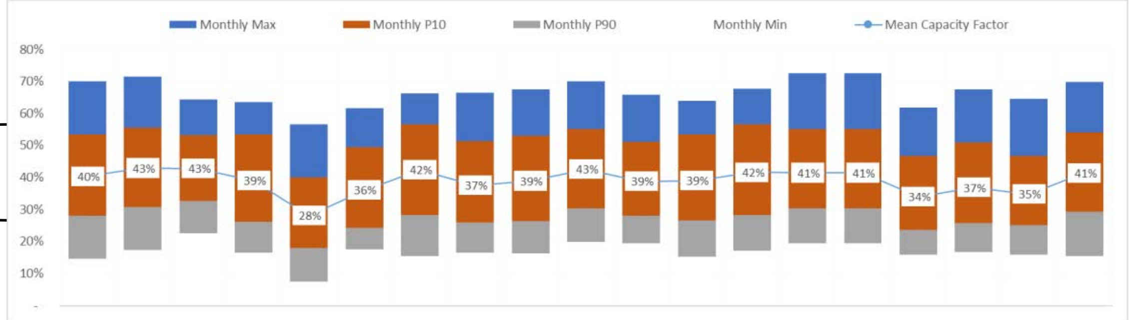
There is a modest winter and spring bias in the seasonal pattern and a small time-time bias in the daily pattern on average

There is a very high daily variation in the wind profiles. The greatest volatility is around is between days. This falls to 25% between months and 7% between years.

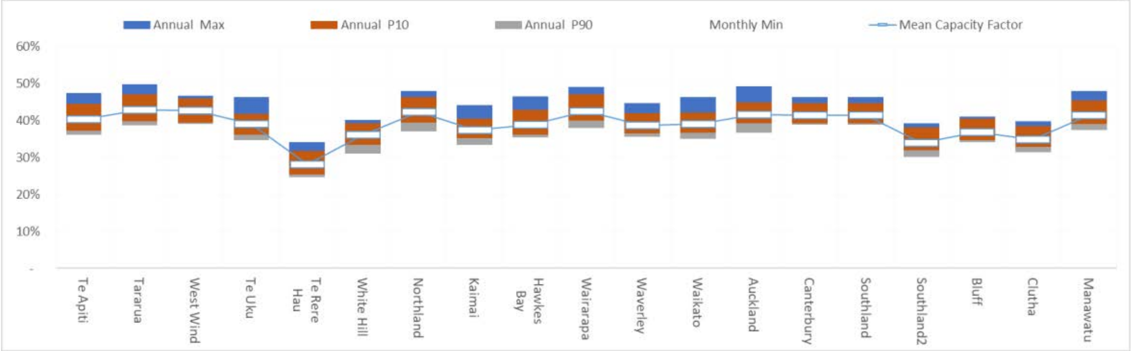
70% daily volatility



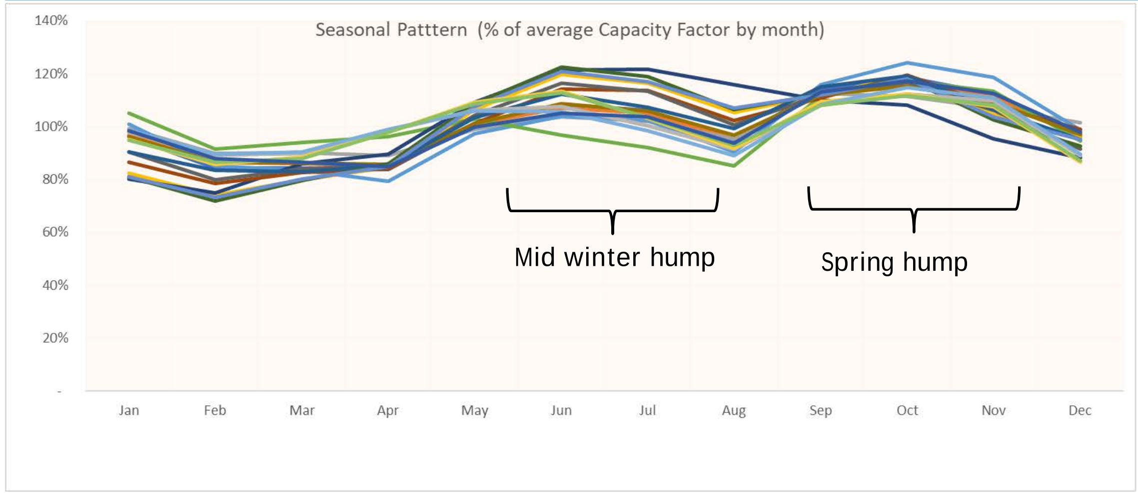
25% daily volatility

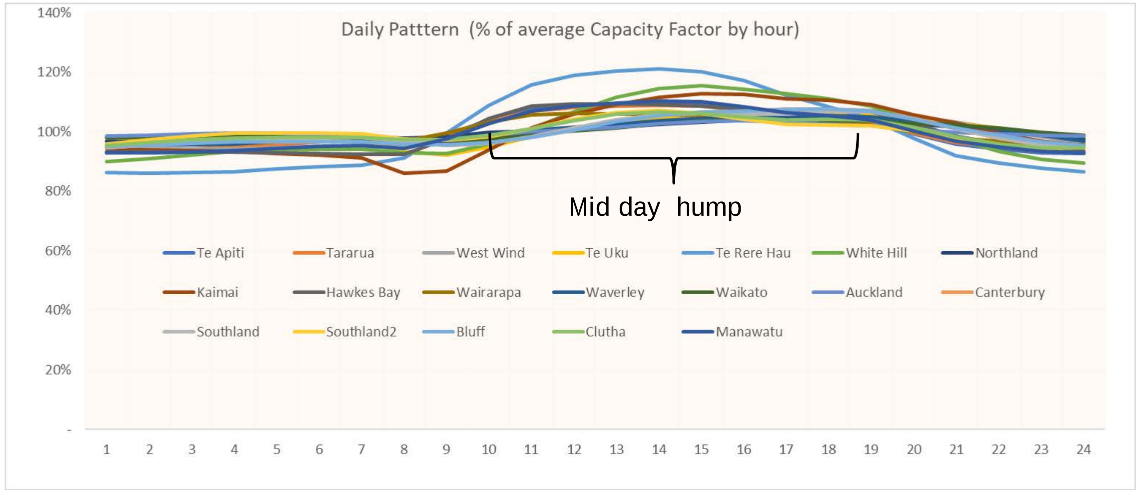


7% annual volatility



The average seasonal and daily patterns of supply show slight mid-winter,spring and mid-day humps.





There is a high correlation between wind profiles within the Manawatu. The correlation falls off with distance, but is still is reasonably high at 35-45% in the South Island.

The cross corelation matrix shows the relationship between variation between all pairs of wind profiles. The highest cross correlations are shown in green and the lowest in red.

The correlations are greatest on a monthly basis, lower on a daily basis and also lower again on an hourly basis.

There is a 90% + corelation between profiles within the Manawatu, this falls towards 50% for other NI regions, and down to 40% for South Island sites and Northland.

The benefits from regional diversification of wind are significant, but not overwhelming.

Hourly

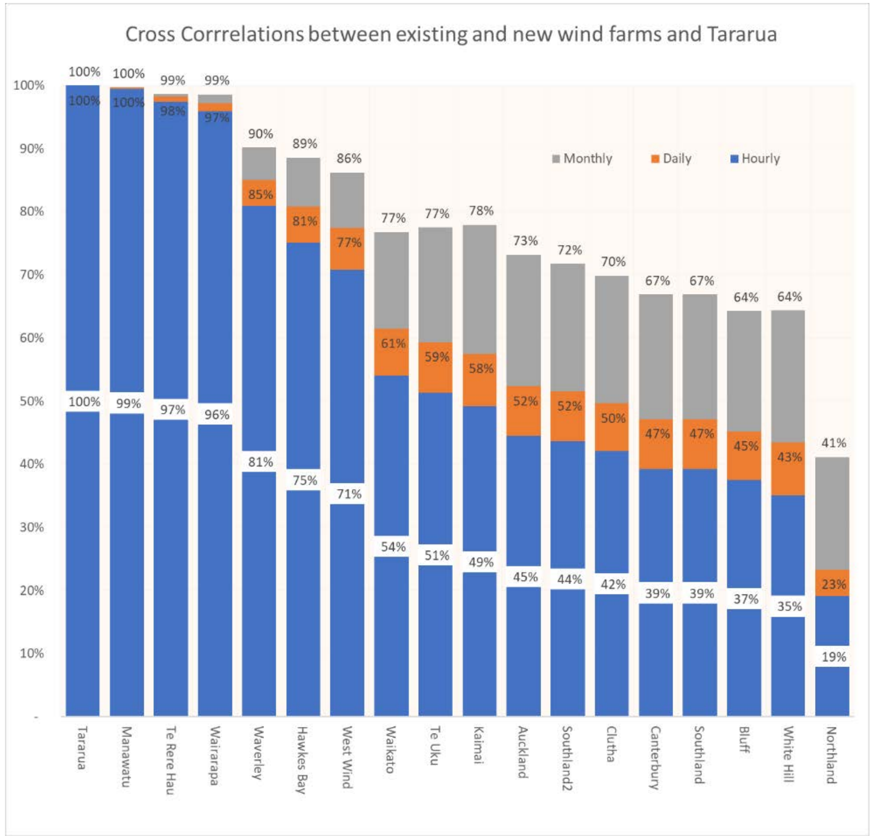
	Te Apiti	Tararua	West Wind	Te Uku	Te Rere Hau	White Hill	Northland	Kaimai	Hawkes Bay	Wairarapa	Waverley	Waikato	Auckland	Canterbury	Southland	Southland2	Bluff	Clutha	Manawatu
Te Apiti	100%																		
Tararua	100%	100%																	
West Wind	69%	71%	100%																
Te Uku	53%	51%	31%	100%															
Te Rere Hau	98%	97%	71%	51%	100%														
White Hill	35%	35%	29%	14%	37%	100%													
Northland	20%	19%	16%	63%	19%	(4%)	100%												
Kaimai	51%	49%	25%	92%	49%	14%	59%	100%											
Hawkes Bay	77%	75%	53%	70%	75%	19%	42%	66%	100%										
Wairarapa	96%	96%	78%	48%	94%	33%	19%	45%	75%	100%									
Waverley	81%	81%	66%	60%	80%	27%	30%	54%	71%	76%	100%								
Waikato	56%	54%	35%	98%	53%	13%	62%	87%	73%	51%	65%	100%							
Auckland	46%	45%	27%	96%	44%	11%	72%	90%	65%	42%	54%	93%	100%						
Canterbury	40%	39%	26%	23%	41%	84%	4%	22%	27%	37%	32%	23%	20%	100%					
Southland	40%	39%	26%	23%	41%	84%	4%	22%	27%	37%	32%	23%	20%	100%	100%				
Southland2	44%	44%	28%	31%	45%	76%	11%	30%	34%	42%	36%	31%	28%	90%	90%	100%			
Bluff	38%	37%	26%	20%	39%	86%	1%	20%	24%	35%	30%	20%	18%	95%	95%	82%	100%		
Clutha	43%	42%	25%	30%	43%	73%	10%	29%	33%	40%	35%	30%	28%	93%	93%	98%	84%	100%	
Manawatu	99%	99%	73%	48%	98%	36%	17%	46%	72%	96%	80%	51%	41%	39%	39%	43%	37%	41%	100%

Daily

Te Apiti	100%																		
Tararua	100%	100%																	
West Wind	76%	77%	100%																
Te Uku	61%	59%	38%	100%															
Te Rere Hau	99%	98%	77%	58%	100%														
White Hill	44%	43%	36%	18%	46%	100%													
Northland	24%	23%	18%	69%	22%	(4%)	100%												
Kaimai	59%	58%	31%	95%	57%	18%	67%	100%											
Hawkes Bay	82%	81%	62%	78%	80%	24%	48%	74%	100%										
Wairarapa	97%	97%	83%	57%	96%	42%	23%	54%	81%	100%									
Waverley	85%	85%	72%	67%	84%	34%	35%	61%	79%	81%	100%								
Waikato	63%	61%	42%	99%	60%	17%	68%	91%	81%	59%	71%	100%							
Auckland	54%	52%	33%	98%	51%	15%	77%	94%	73%	50%	61%	96%	100%						
Canterbury	48%	47%	31%	29%	48%	88%	5%	27%	33%	45%	39%	28%	25%	100%					
Southland	48%	47%	31%	29%	48%	88%	5%	27%	33%	45%	39%	28%	25%	100%	100%				
Southland2	52%	52%	34%	38%	53%	81%	13%	36%	41%	51%	44%	37%	34%	94%	94%	100%			
Bluff	46%	45%	31%	25%	47%	90%	2%	24%	30%	43%	37%	25%	22%	98%	98%	88%	100%		
Clutha	51%	50%	30%	37%	51%	78%	12%	35%	40%	48%	42%	37%	34%	95%	95%	99%	90%	100%	
Manawatu	99%	100%	80%	56%	99%	44%	21%	54%	78%	97%	84%	58%	49%	47%	47%	50%	45%	48%	100%

Monthly

Te Apiti	100%																		
Tararua	100%	100%																	
West Wind	85%	86%	100%																
Te Uku	79%	77%	61%	100%															
Te Rere Hau	99%	99%	86%	73%	100%														
White Hill	64%	64%	54%	35%	67%	100%													
Northland	43%	41%	32%	77%	35%	2%	100%												
Kaimai	79%	78%	59%	97%	75%	37%	75%	100%											
Hawkes Bay	89%	89%	79%	91%	86%	46%	67%	88%	100%										
Wairarapa	98%	99%	90%	77%	97%	62%	41%	76%	89%	100%									
Waverley	91%	90%	80%	83%	88%	53%	54%	82%	88%	88%	100%								
Waikato	78%	77%	62%	99%	72%	34%	78%	95%	91%	76%	84%	100%							
Auckland	74%	73%	57%	99%	69%	31%	83%	96%	88%	73%	80%	99%	100%						
Canterbury	67%	67%	49%	48%	67%	92%	16%	47%	55%	65%	57%	47%	44%	100%					
Southland	67%	67%	49%	48%	67%	92%	16%	47%	55%	65%	57%	47%	44%	100%	100%				
Southland2	72%	72%	53%	58%	71%	86%	27%	56%	65%	70%	64%	57%	55%	97%	97%	100%			
Bluff	65%	64%	49%	43%	66%	94%	11%	42%	51%	62%	54%	42%	39%	99%	99%	94%	100%		
Clutha	71%	70%	50%	57%	69%	84%	27%	56%	63%	68%	62%	56%	54%	97%	97%	99%	94%	100%	
Manawatu	100%	100%	88%	74%	99%	66%	37%	75%	86%	98%	89%	73%	69%	66%	66%	70%	64%	68%	100%

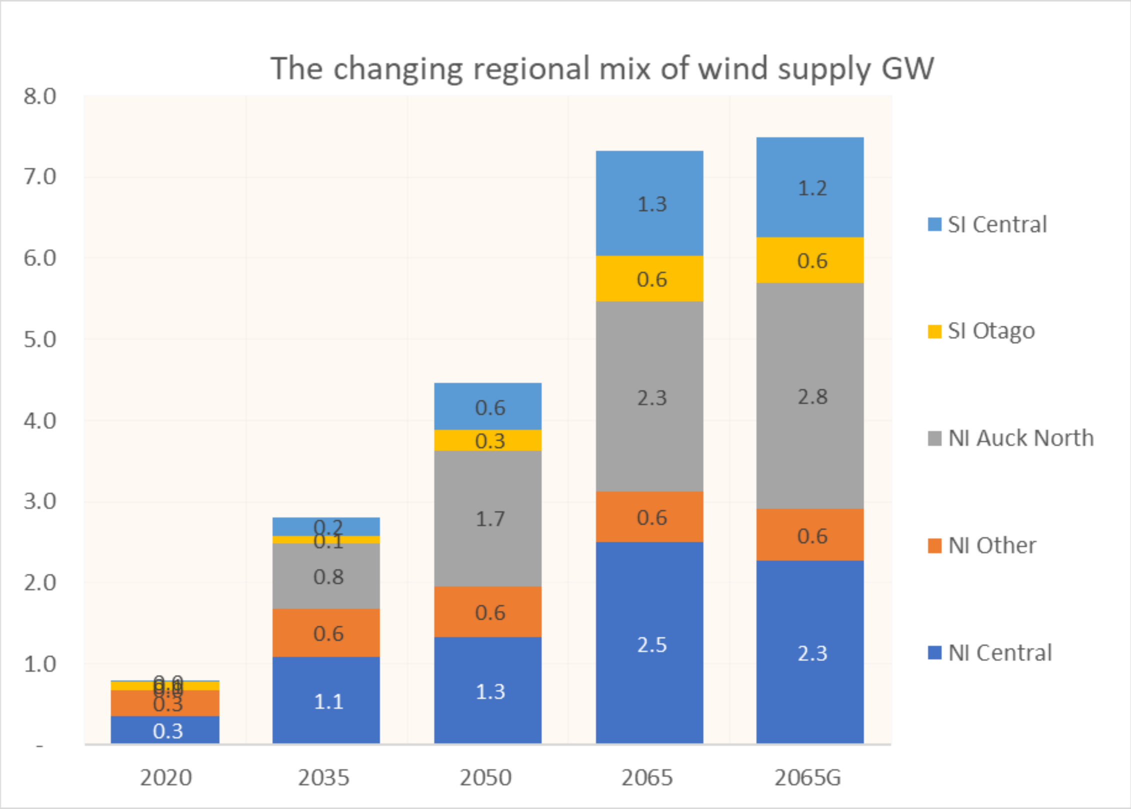


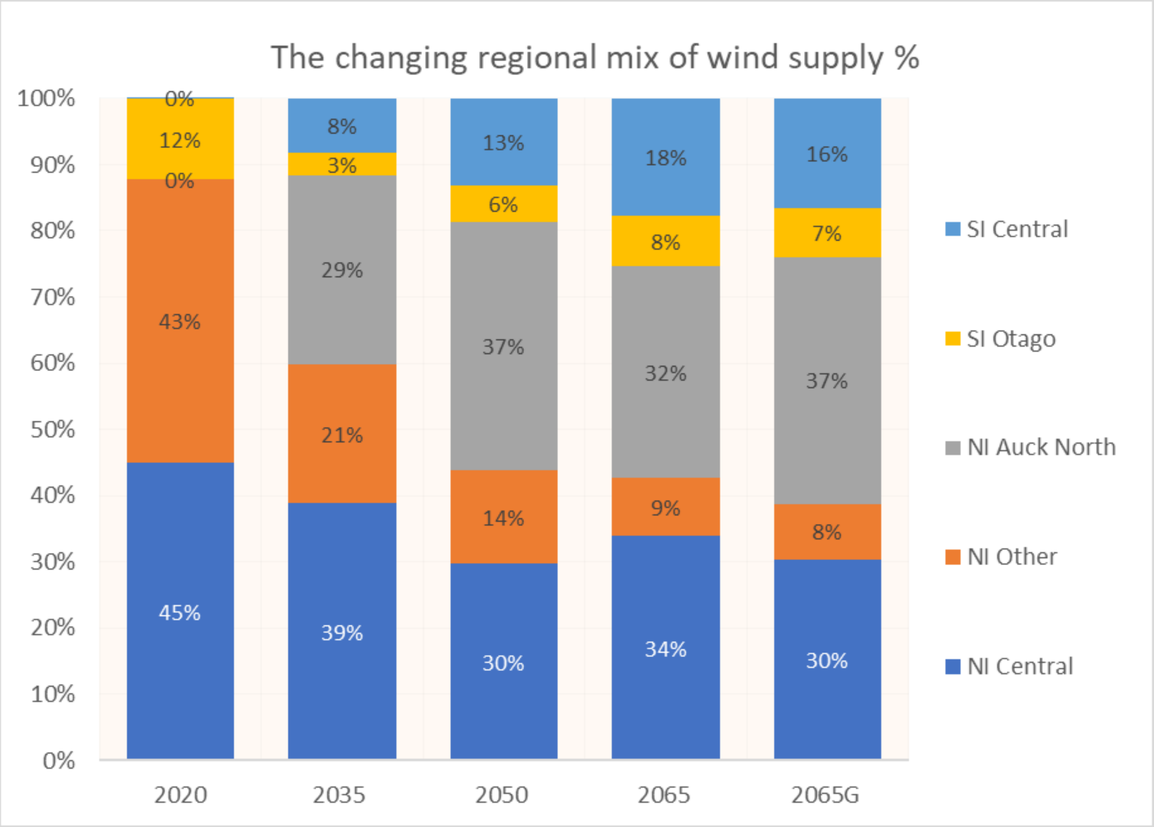
Note: the correlation is measured using the Pearson Product-Moment Correlation. The Northland result is derived from renewable ninja website, but appears to be an outlier. This profile is not used in the modelling.

The changing regional mix of wind supply - 100% renewable worlds with no NZ Battery

It is assumed that there is a significant increase in new wind in the upper North island to take advantage of wind diversity and better locational prices. South Island development occurs from 2050 onwards. This has a diversity benefit but a locational price disadvantage.

On a percentage basis Central NI wind falls from the current 45% to around 33% of supply, other NI to 40% and 25% in the South Island.



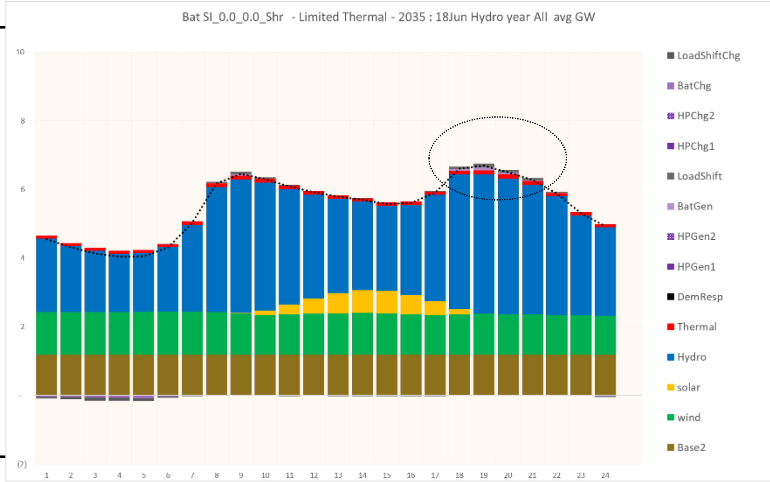


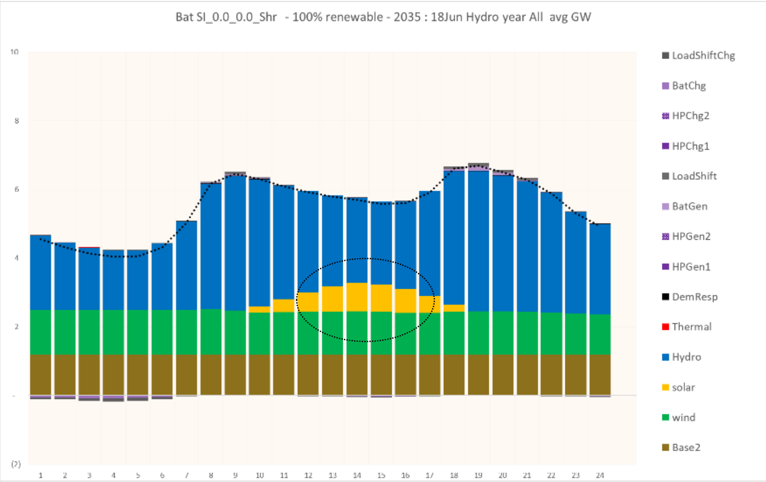
APPENDIX 2: CHANGES IN THE DAILY GENERATION PATTERNS DURING TYPICAL WEEKS IN WINTER AND SUMMER

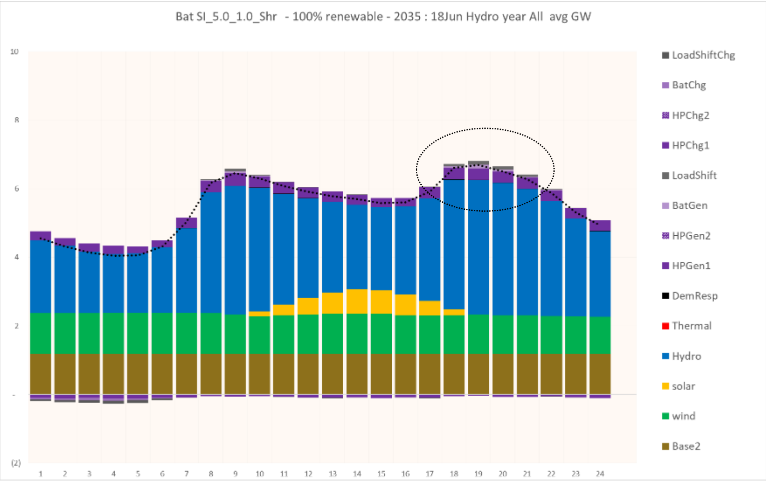
Averaged daily patterns of supply in 2035 with modest levels of solar and EVs

Limited Thermal	100% Renewable without NZ Battery	100% Renewable with NZ Battery - SI 5TWh/1.0GW

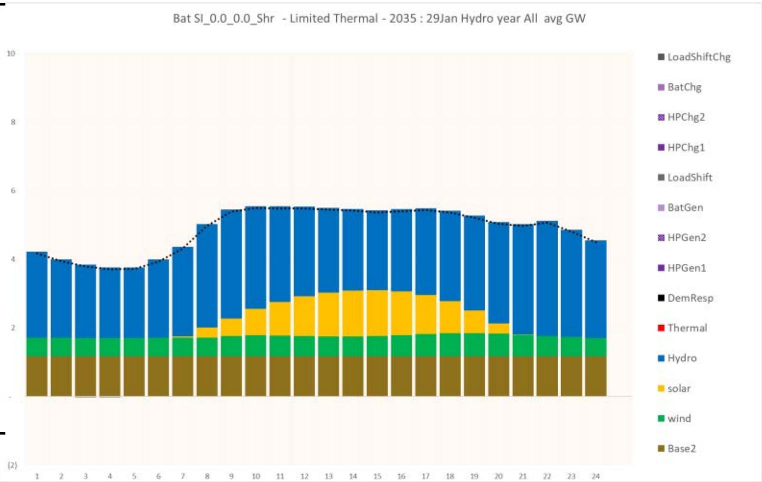
A typical winter week

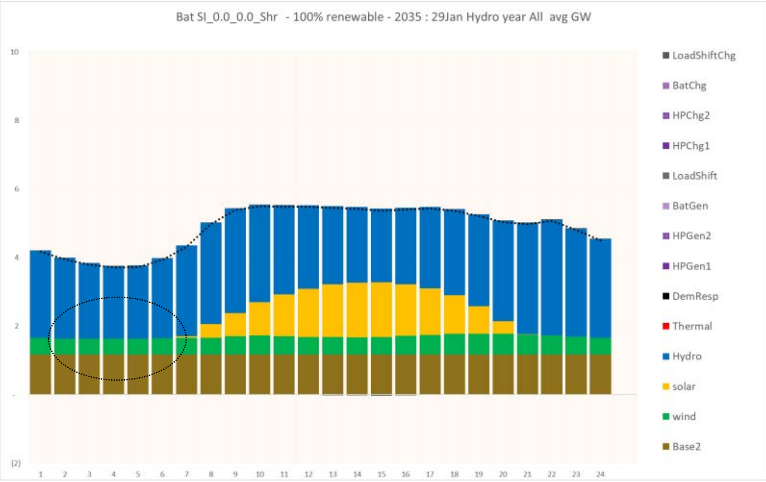


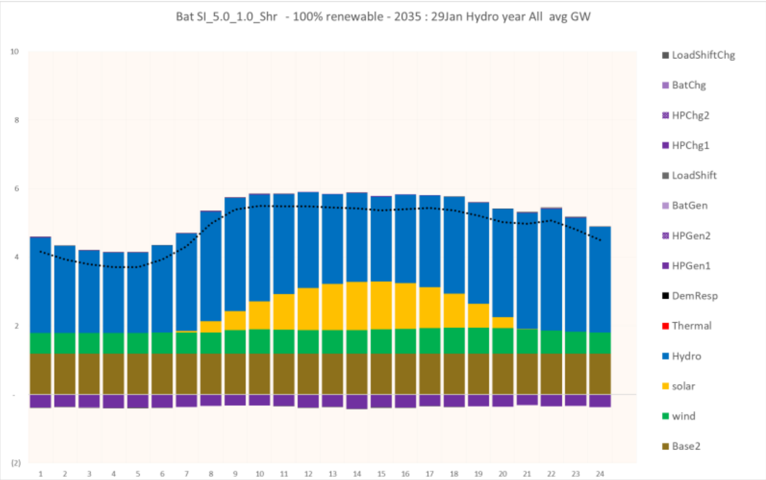




A typical Summer week







The winter peak demand is driven by the underlying demand shape which peaks around 6-8p. This is met by gas peakers and load shifting

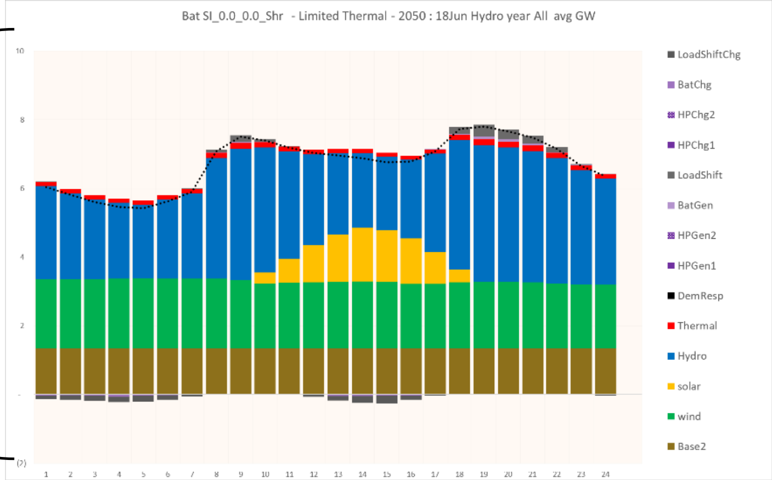
There is only a most level of solar in 2035, and this does nor significantly contribute to wither peak demand. Wind appears to be lower in the summer

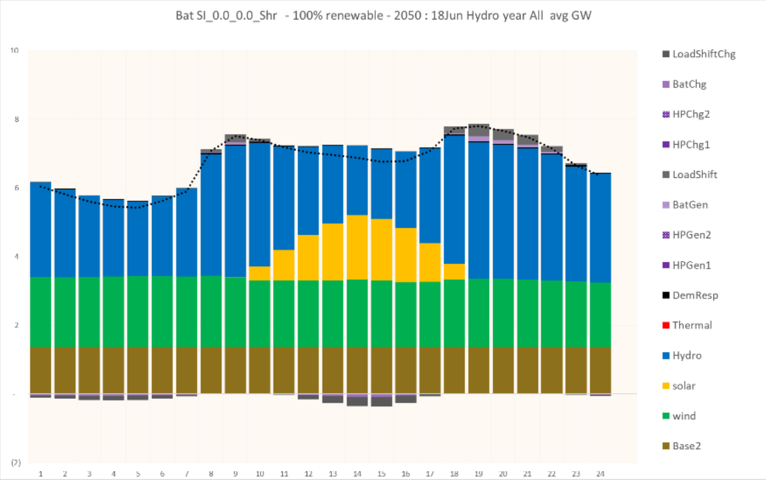
The charts show the contribution of each source of supply and flexibility in GW in each hour of a typical working day in winter and in summer. The results are averaged over all 86 weather years.

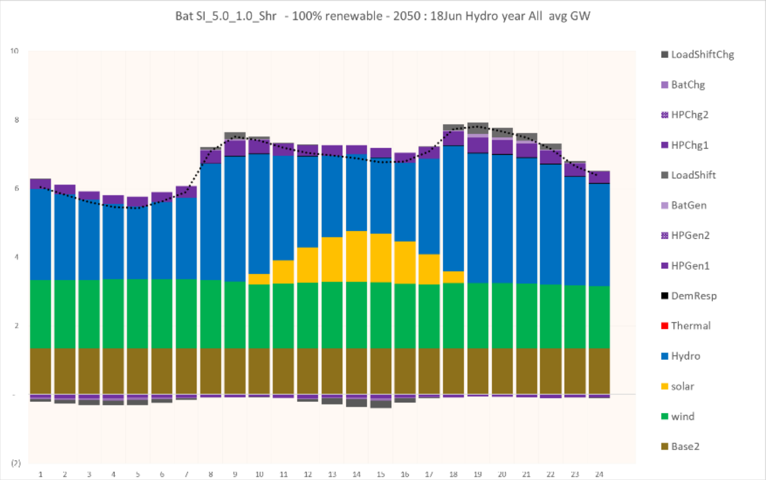
Averaged daily patterns of supply in 2050 with significant electrification and solar

Limited Thermal	100% Renewable without NZ Battery	100% Renewable with NZ Battery - SI 5TWh/1.0GW

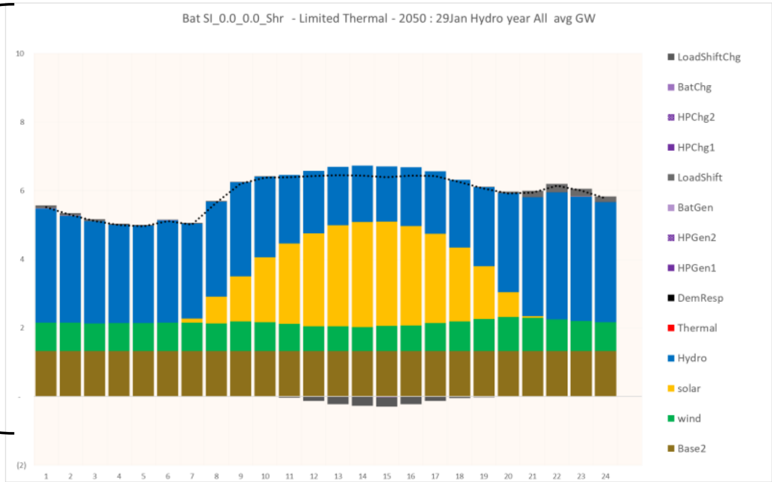
A typical winter week

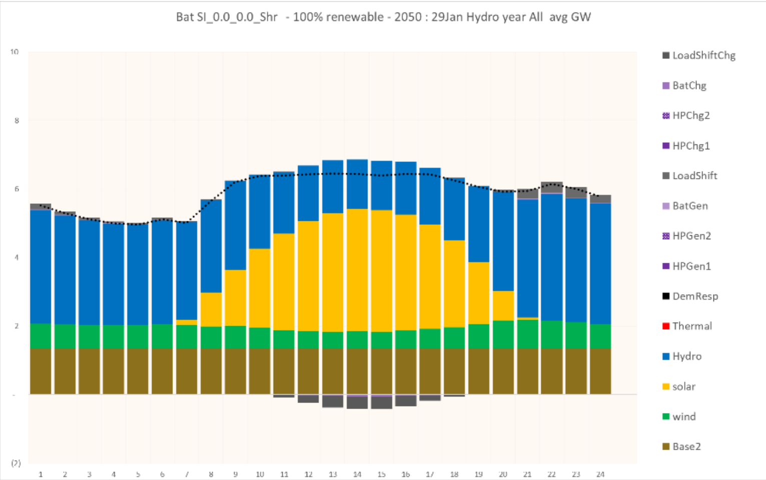


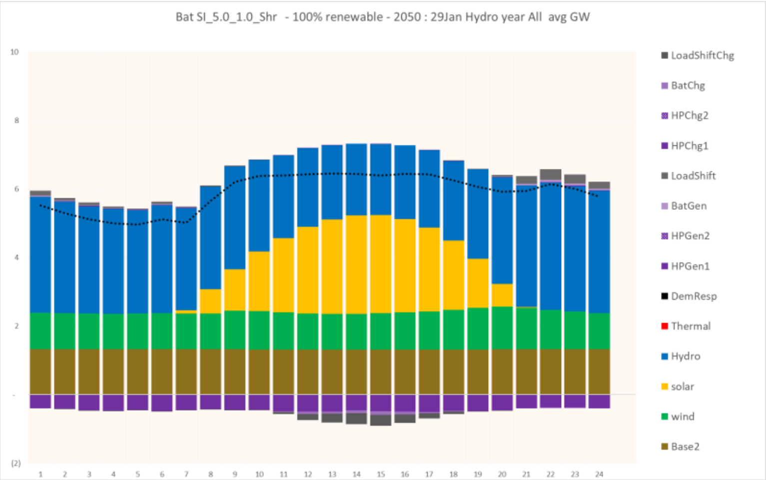




A typical Summer week







The charts show the contribution of each source of supply and flexibility in GW in each hour of a typical working day in winter and in summer. The results are averaged over all 86 weather years.

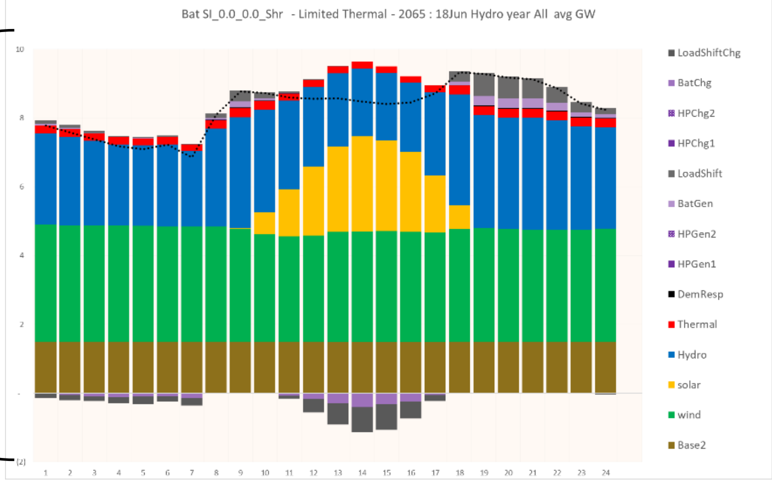
Averaged daily patterns of supply in 2065 with full transport electrification and high solar

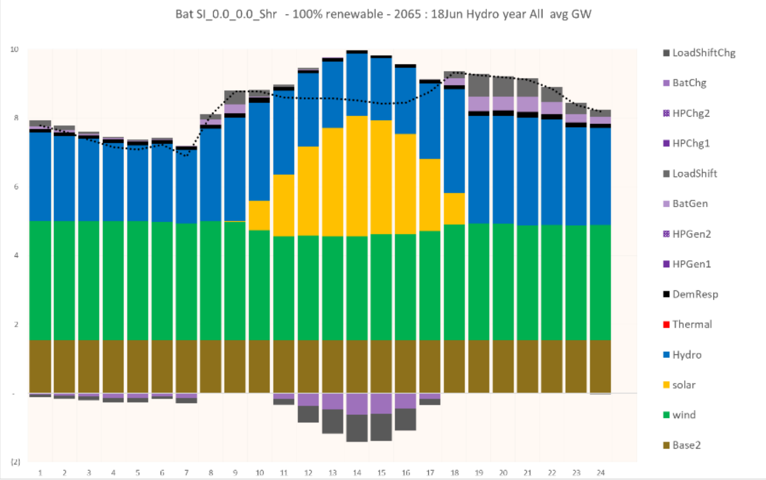
concept consulting

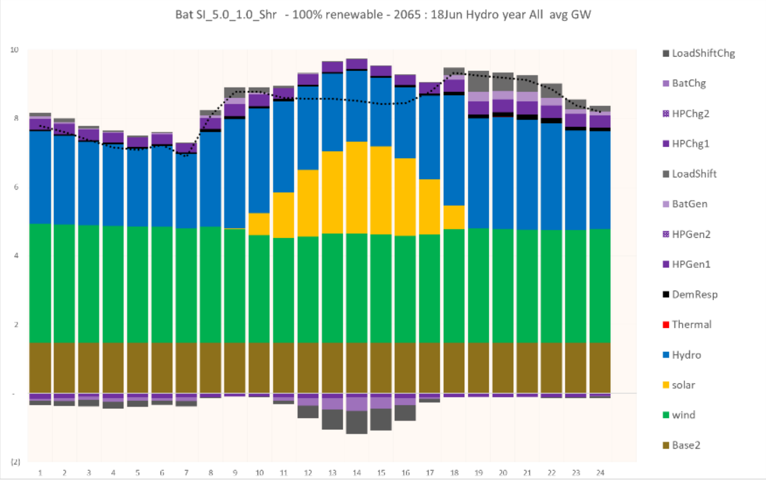
JC2

Limited Thermal	100% Renewable without NZ Battery	100% Renewable with NZ Battery - SI 5TWh/1.0GW

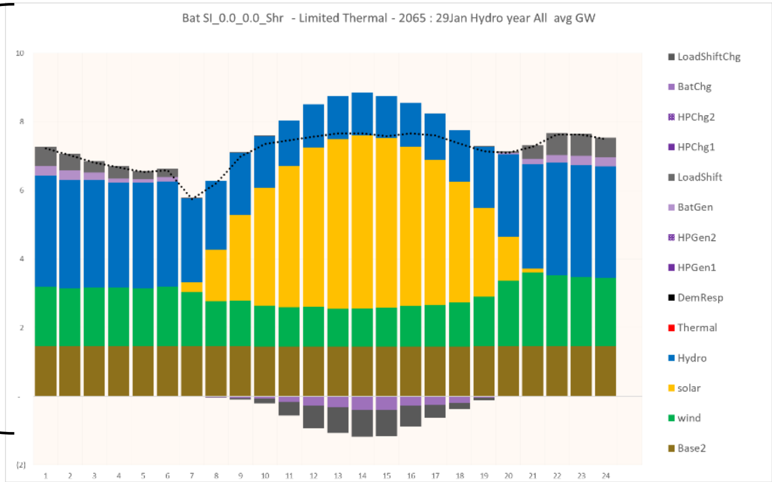
A typical winter week

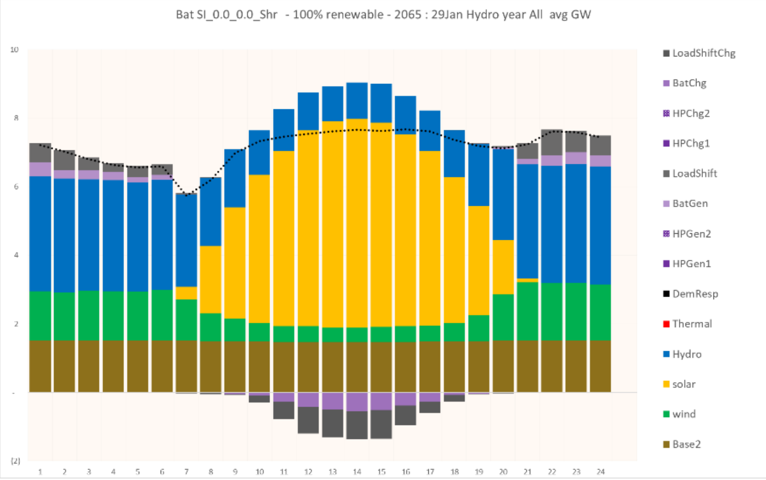


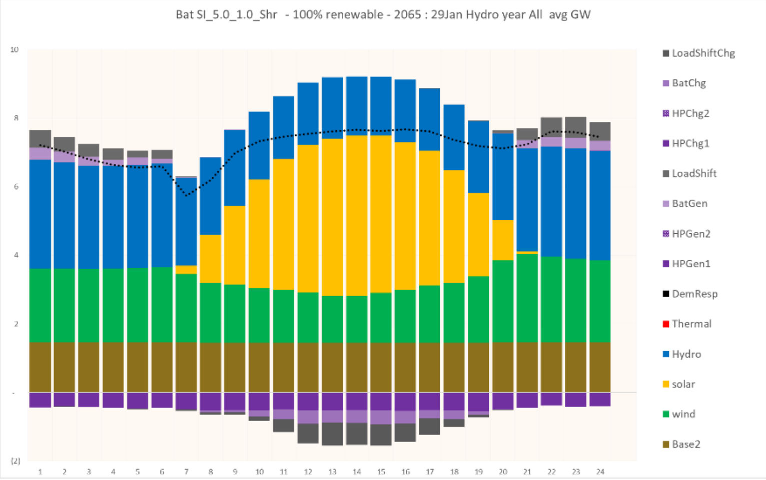




A typical Summer week



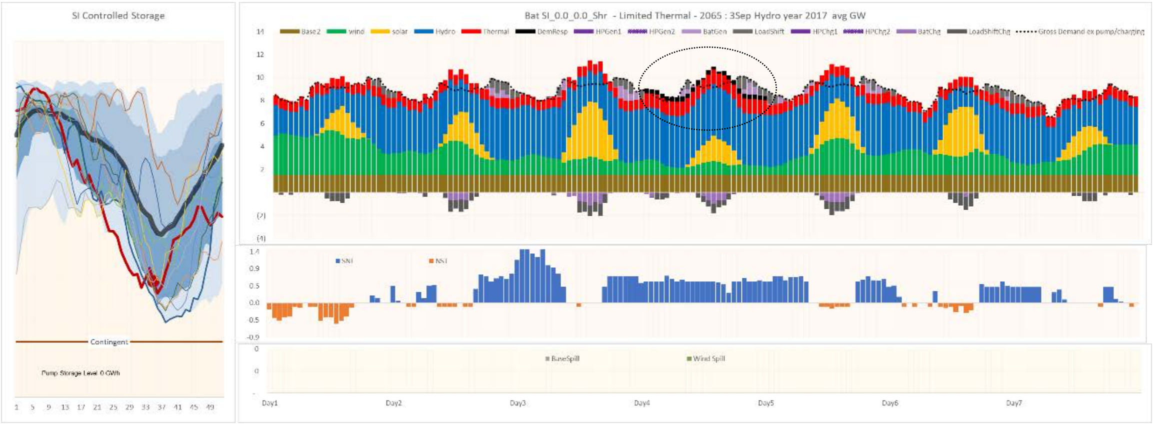




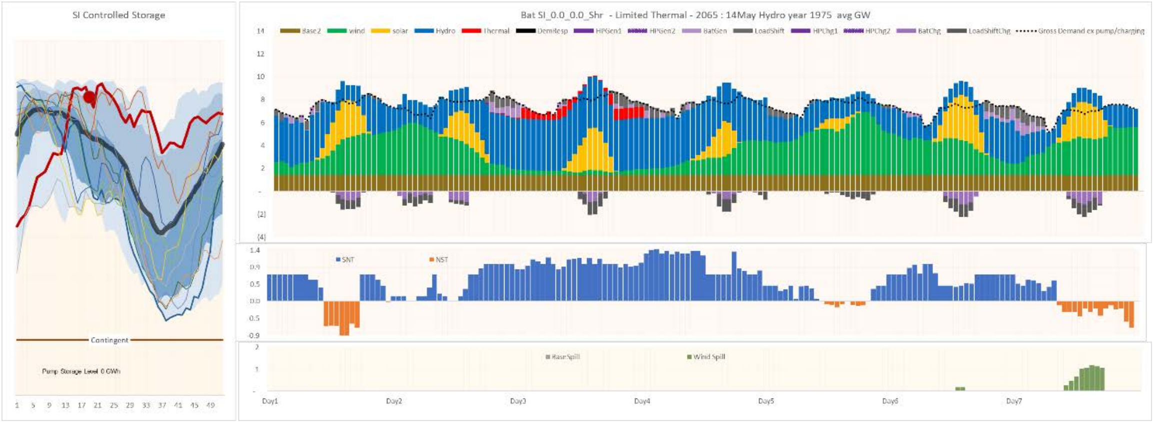
The charts show the contribution of each source of supply and flexibility in GW in each hour of a typical working day in winter and in summer. The results are averaged over all 86 weather years.

Examples of supply by hour over sample weeks - in 2065 - limited thermal without NZ Battery

Early & late Winter - low and high hydro storage



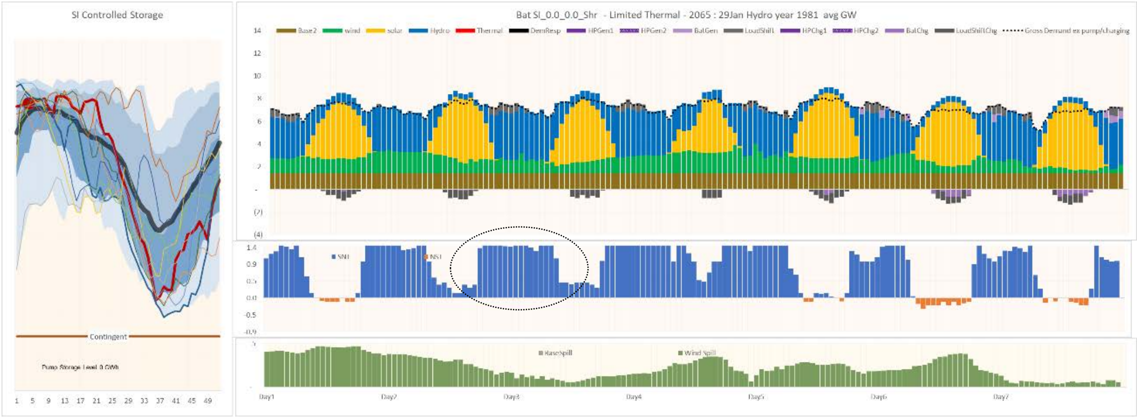
Risk of hydro shortage rising; excess from NI is sent SI to conserve storage. Batteries meet peak after sunset and are charged in middle of day or night time depending on wind.



Risk of hydro shortage low; little wind during workdays. South->north transfer during low wind days, batteries are filled during middle of day and at night, and meet peak after sunset ; but peakers are needed also.

Summer - low and high wind

Risk of hydro spill moderate; moderate low wind; batteries shift solar from midday to after sunset, Some wind "spill" occurs when North->South HVDC hits limit.



Risk hydro spill is high; high wind and solar ; wind is very high and so wind "spill" occurs. HVDC hits SI->NI limit to avoid hydro spill, but wind spill occurs in NI as price fall below wind offer price.

Examples of supply by hour over sample weeks - in 2065 - 100% renewable with a NZ Battery (SI 5TWh/1GW)

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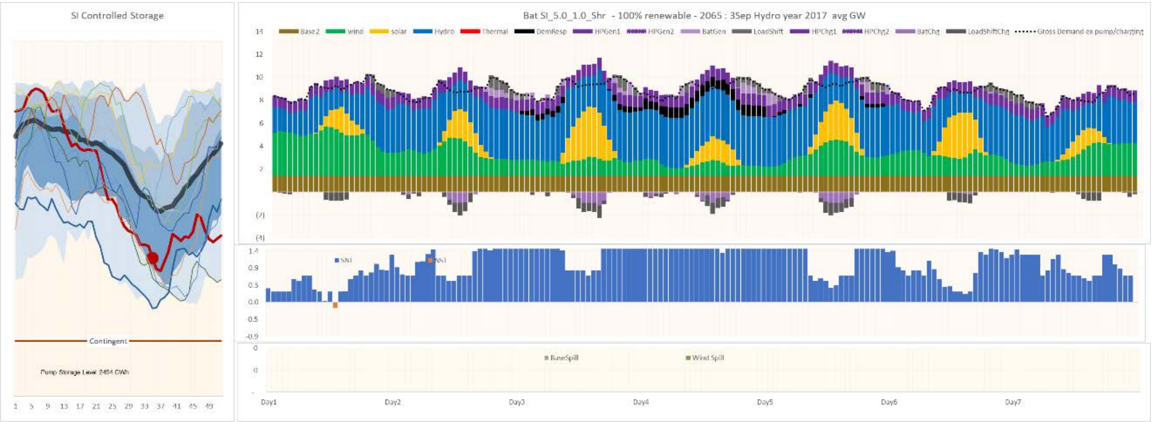
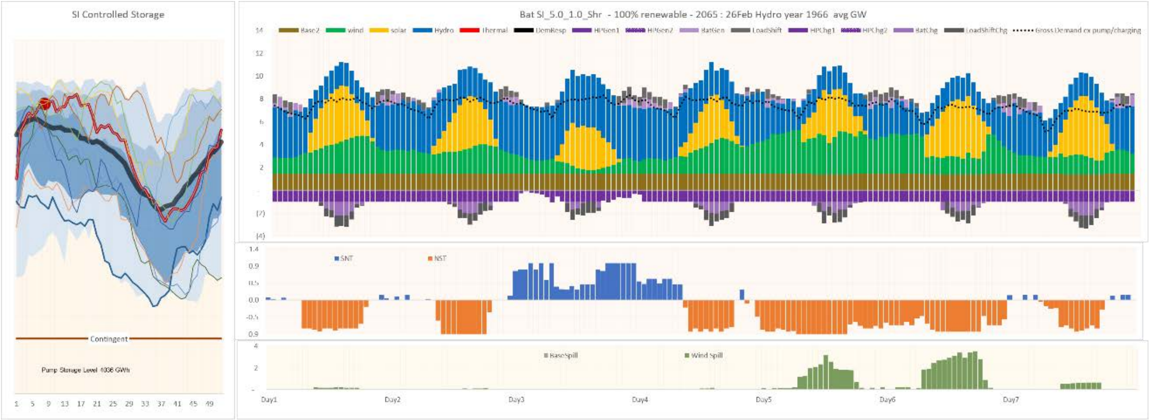
Late Winter - low and high hydro storage - NZ battery is used to cover dry years and to meet periods of low wind , but is subject to HVDC constraints



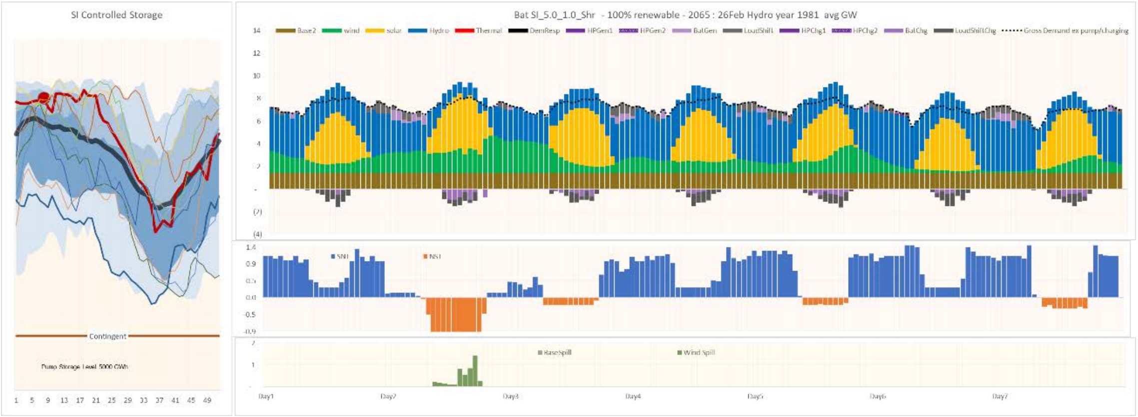
Risk of hydro shortage rising; excess from NI is sent SI to conserve storage. Batteries meet peak after sunset and are charged in middle of day or night time depending on wind. NZ Battery operates all week.

Summer - low and high wind - NZ battery is typically being filled with supply that would **otherwise be "spilled", but there are limits from HVDC and NZ battery may be full**



Risk of hydro spill moderate; moderate low wind; batteries shift solar from midday to after sunset. Some geothermal and wind spill occur in the middle of the day when NZ Battery and HVDC hits capacity limit

Risk of hydro shortage low; little wind during workdays. South->north transfer during low wind days, batteries are filled during middle of day and at night, and meet peak after sunset ; NZ Battery runs but is limited by HVDC.



Risk hydro spill is high; high wind and solar ; NZ Battery is full so no room to store "spill" as a result spill is very high.

APPENDIX 3: ANALYSIS OF GENERATION CONTRIBUTION TO PERIODS OF SCARCITY AND SURPLUS

Contribution of renewables to periods of surplus and scarcity - Chart explanation

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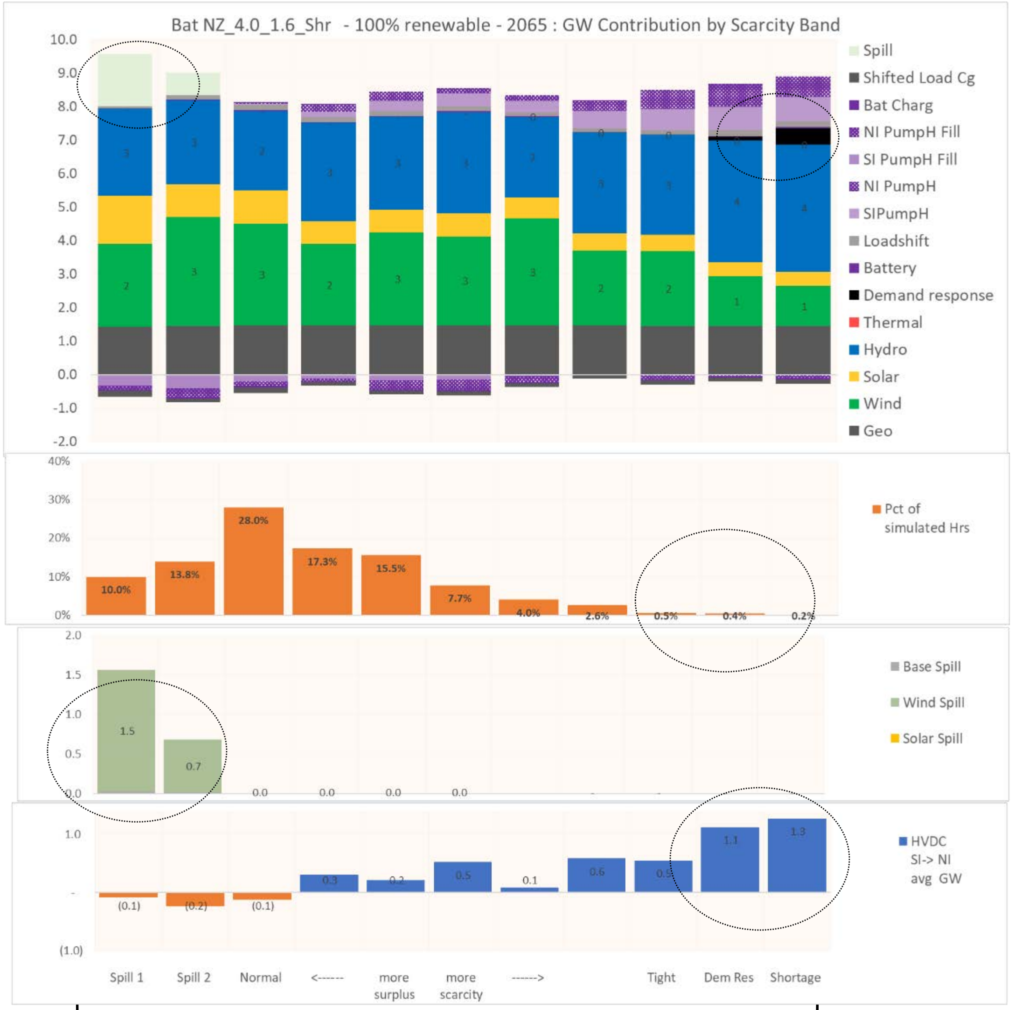
Illustrative Chart

Average GW contribution of supply to meet demand in each "bin"

% of simulated periods in each "bin"

Average GW of "spill" by type in each bin

Average GW of HVDC Transfer



Individual "bins" ranked from low to high risk of scarcity

Chart explanation

- These charts show the average MW contribution of different generation types in blocks of relative scarcity and shortage.
- **The charts are made by putting each simulated period in to number of "bins" which** are reflect the balance of supply and demand.
- **Bins with excess supply and high risk of "spill" are show on the left and bins with** relative shortage and high risk of demand response being required are shown to the right.
- The charts are useful to assess the value contribution of the different types of supply including intermitted supply (solar and wind), dispatchable hydro and thermal, and batteries of different sizes and duration.
  - **Note that "Demand response" includes both voluntary curtailed load and shoratges. "Load shifting" is smart shifting of EV charging load within the day.**
  - Batteries include different hours of storage (from 3 to 12 hours) and include that portion of behind the meter batteries that are scheduled according to system need.
- The percentage of periods in each indicated by the probability histogram.
  - The bins to the far right that correspond to demand response and shortage have low probability (typically < 1%) but a very high impact on cost.
- **The expected level of "spill" in each band is shown below. This is wind solar and** geothermal being dispatched off when there is excess supply to meet demand.
  - **The bins to the left include a high risk of "spill" when prices fall below the** minimum offer prices for wind and solar.
- The final chart shows the expected level of South to North transfer on the HVDC link, and illustrates the frequency of link limits being hit.
  - When the average HVDC S->N gets close to 1.4GW there is a high risk the HVDC **limit becomes binding and SI flexible resources can't be fully utilised to meet NI** shortages. Similarly

Contribution of renewables to periods of surplus and scarcity in 2065 : without NZ Battery

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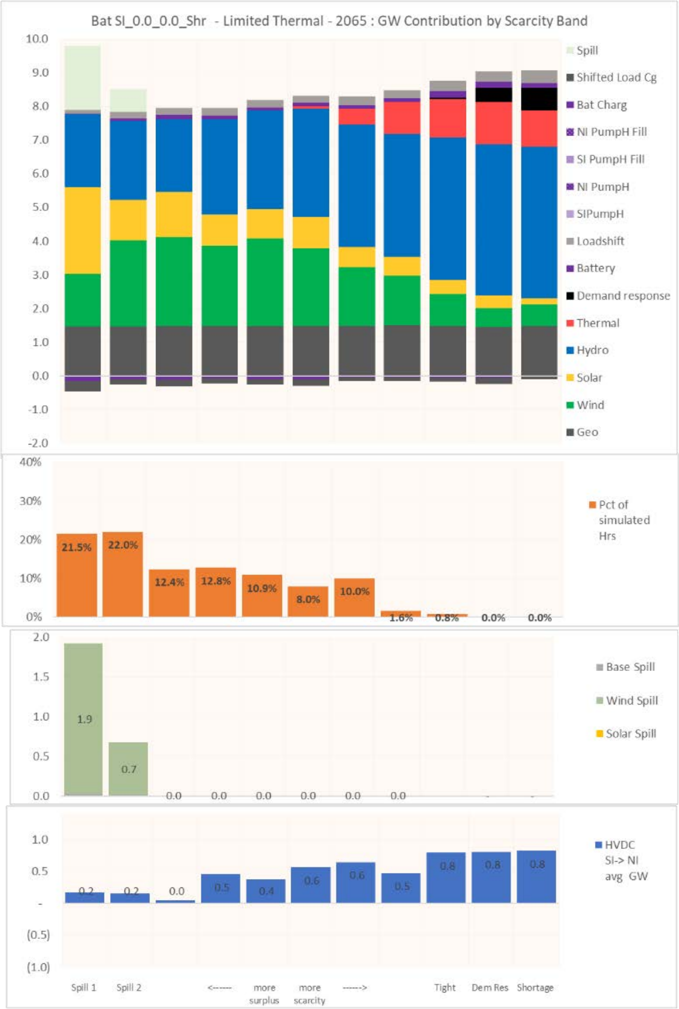
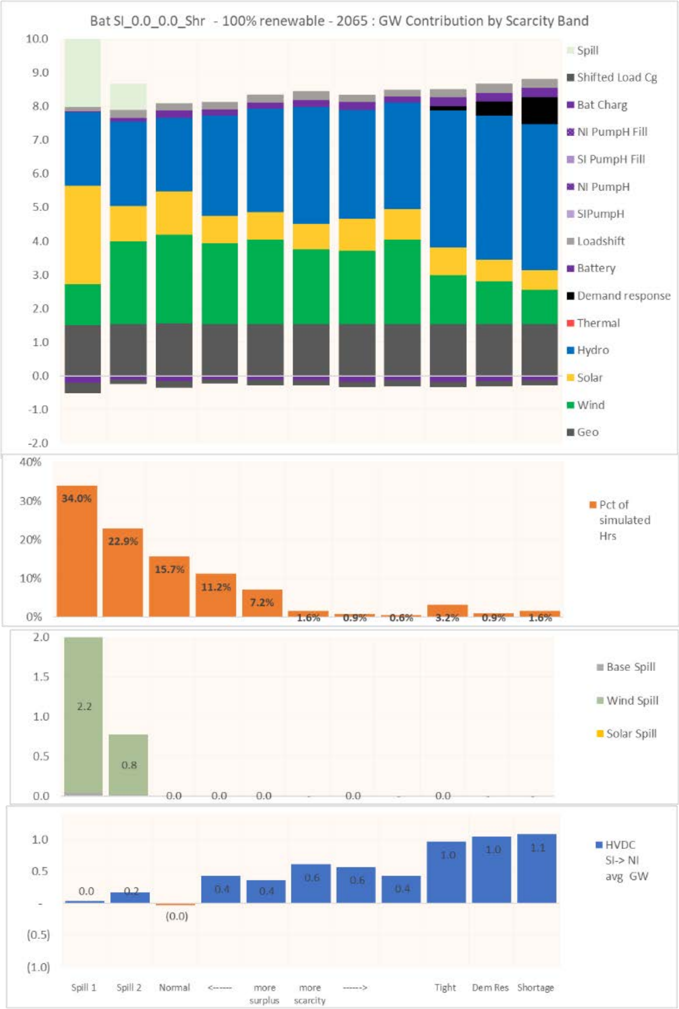
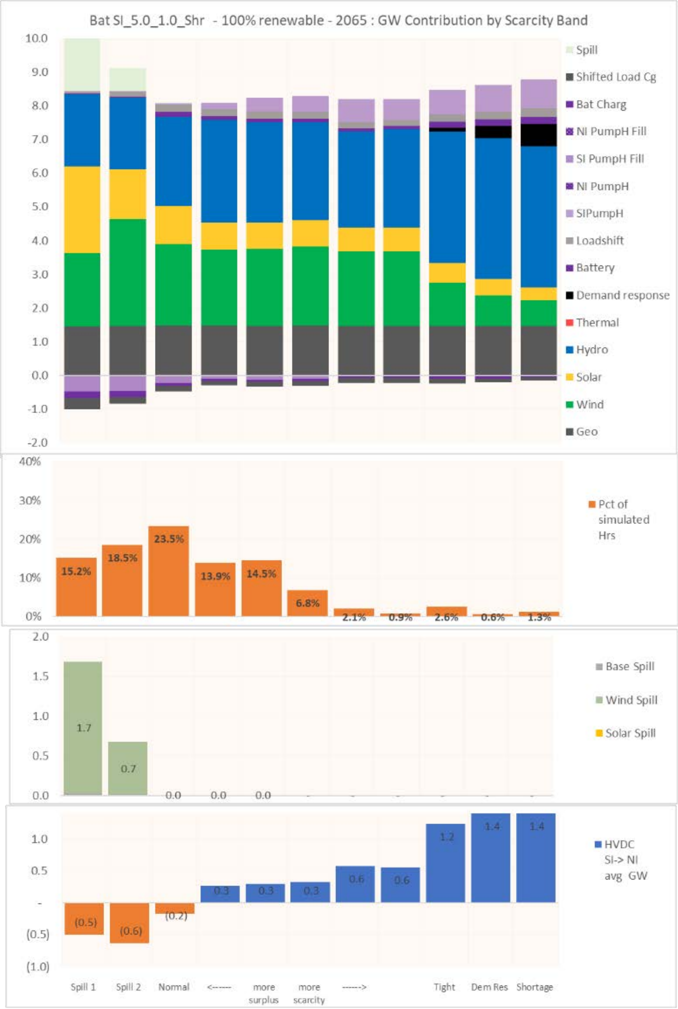
Limited Thermal



100% renewable World



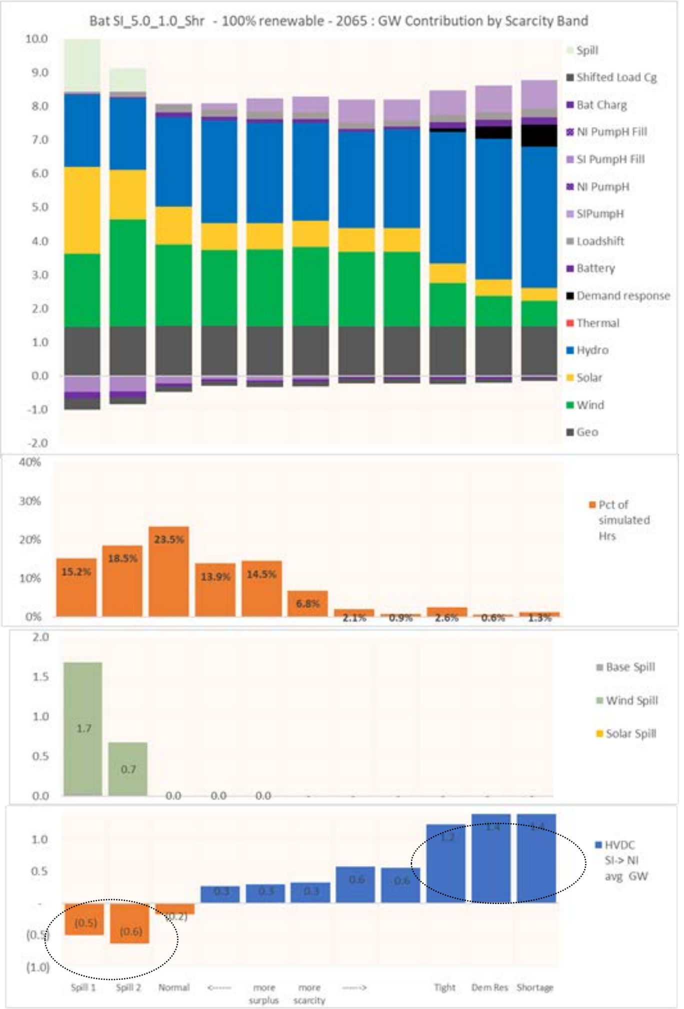
100% renewable World with NZ Battery



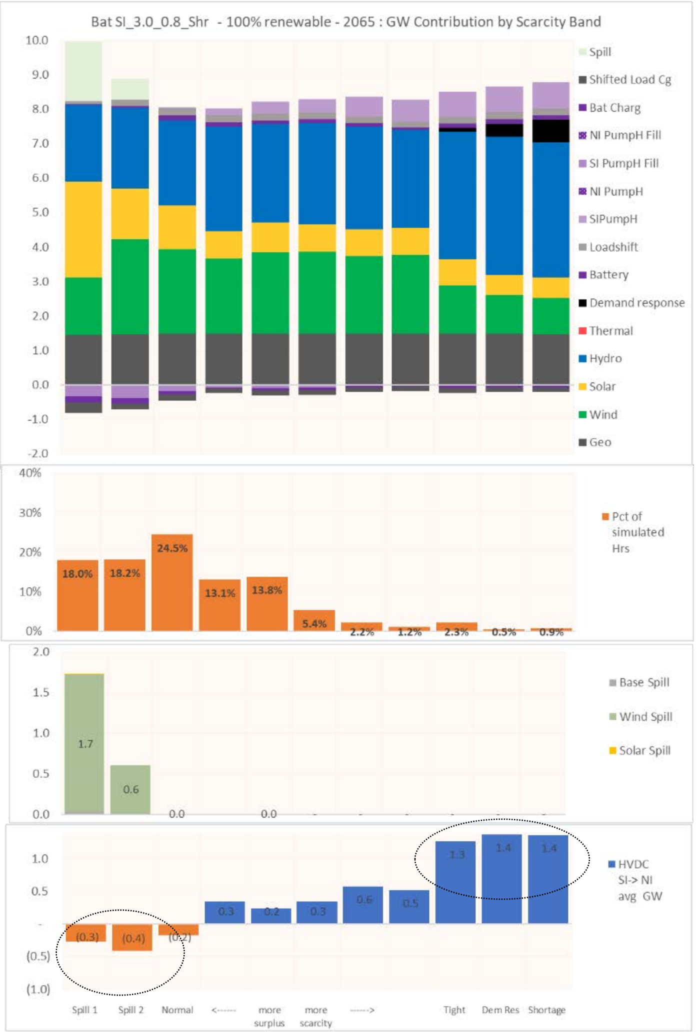
Notes: The horizontal axis is a set of “bins” of modelled periods ranked from periods of highest “spill” risk to highest scarcity/shortage risk. The vertical axis is average GW contribution to meeting demand in each “bin”.

GW contribution to periods of surplus/scarcity in 2065: with SI Battery 0.5 to 1.0GW

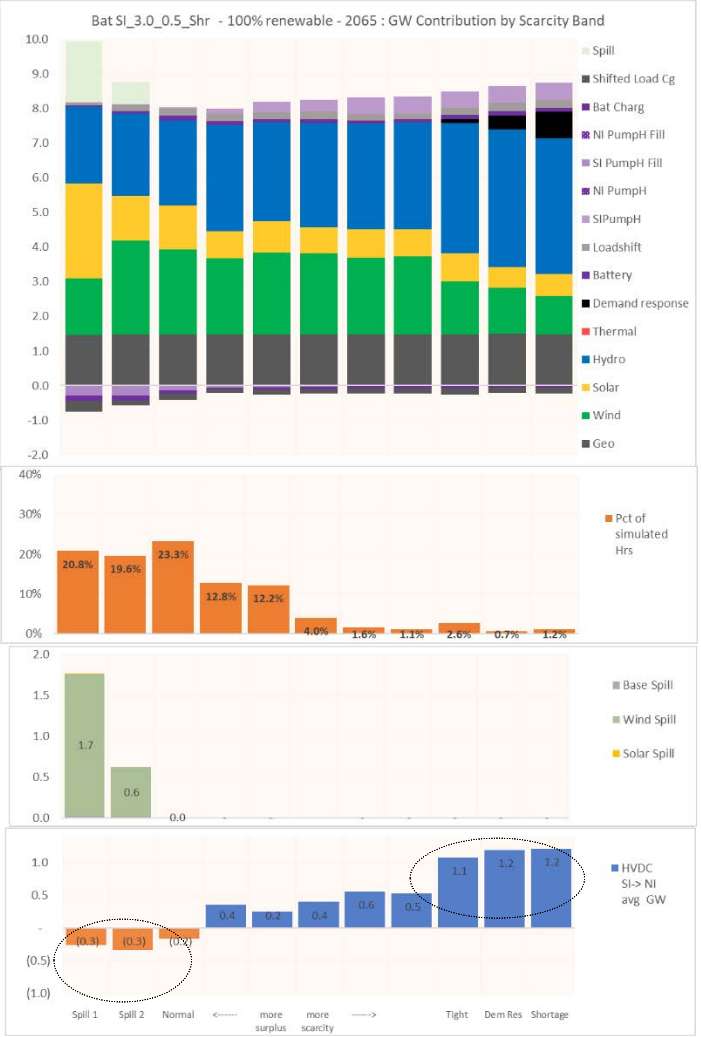
SI 5TWh 1.0GW - 1400MW S->N limit binds in scarcity and N->S limit of 950MW often binds during spill events



SI 3TWh 0.8GW -> 1400MW S-N limit binds scarcity and N->S limit of 950MW occasionally binds during spill events



SI 3TWh 0.5 GW - 1400MW S->N limit is not quite binding during scarcity hours



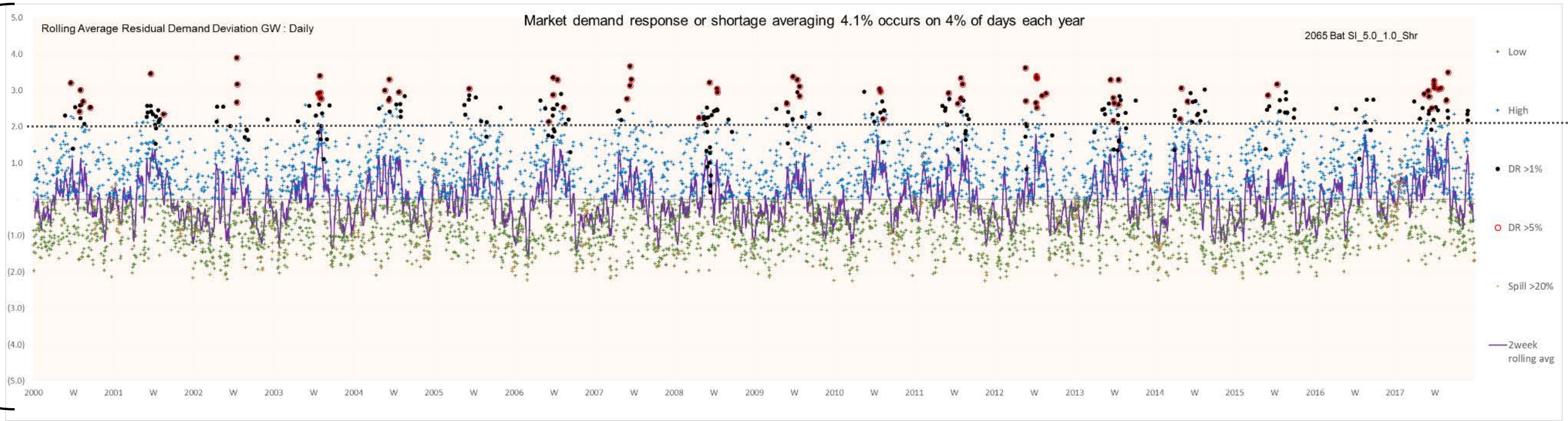
Notes: The horizontal axis is a set of "bins" of modelled periods ranked from periods of highest "spill" risk to highest scarcity/shortage risk. The vertical axis is average GW contribution to meeting demand in each "bin".

APPENDIX 4: THE FREQUENCY AND NATURE OF DEMAND RESPONSE AND SHORTAGE

Residual demand and demand response/shortage chart explanation

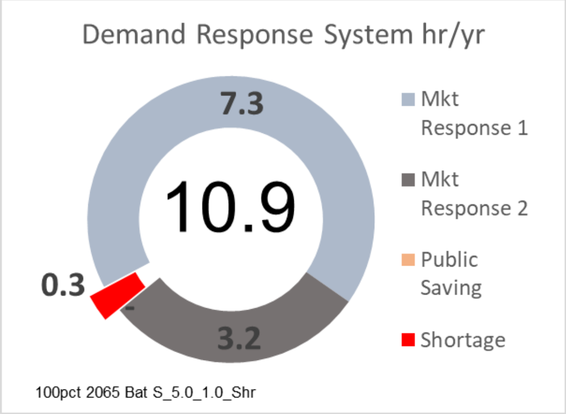
The illustrative demand response/shortage chart shows the incidence of demand response by severity day by day over 18 simulated weather years as a function of residual demand

Residual demand = Demand - wind and solar



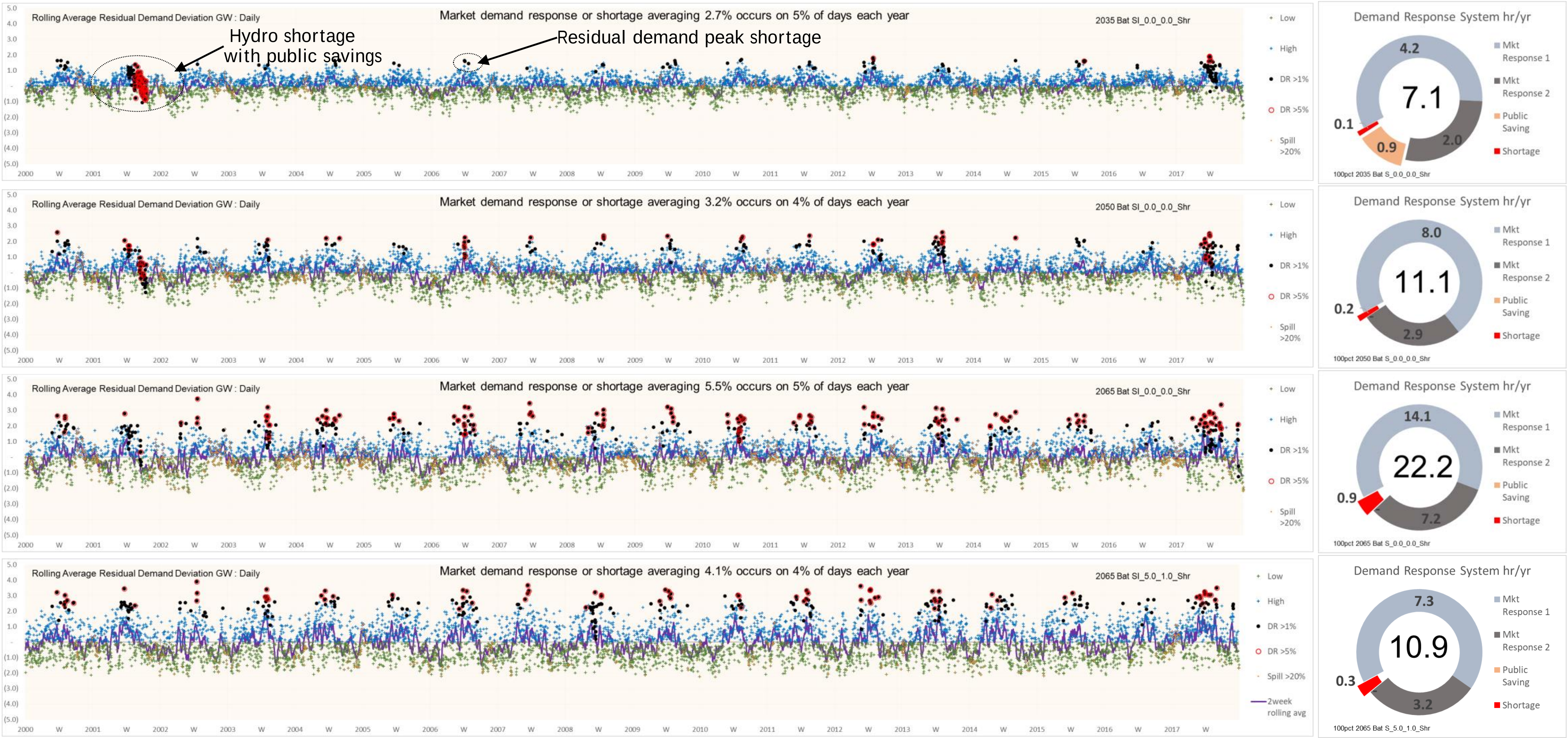
- The chart shows residual demand = demand minus intermittent potential supply from wind and solar. This is expressed in average GW over different time frames (daily + and 2 weekly rolling average) relative to the expected annual average residual demand over all years.
  - Points above zero (blue +) correspond to days with high demand and low wind/solar and points below zero (green +) correspond to periods of low demand and high wind/solar.
  - There is a seasonal pattern to residual demand reflecting the winter oriented seasonal demand shape and the seasonal shape of solar and wind supply. However there is a very large random component reflecting variations in weather driven daily and 2 weekly wind and solar supply.
  - On an average daily basis the system in 2065 need flexible resources to be able to handle variations of plus 4GW and minus 3GW.
- The chart also shows days with simulated demand response/shortage above 1 and 5% of demand as black dots and red circles respectively.
  - **This demand response/shortage represent periods which can't be met from run of river hydro and geothermal and flexible supply** from stored hydro and batteries and peakers (if available).

Demand response measures summary



- Demand response can be converted into system hours per year by dividing the expected demand response in GWh by the total annual demand in GWh and multiplying by 8750 hours.
- The charts shows the system hours for 2 classes of voluntary market demand response (priced at $700/MWh and at $1000-2000/MWh) and 2 forms of shortage (public savings priced at $900/MWh and other involuntary shortages priced at $3000-$15000/MWh).

Residual demand deviation and demand response/shortage - 100pct Renewable no green peakers



Notes: These charts show residual demand (average demand minus solar and wind potential generation in GW) on different rolling time frames from daily to 2 weekly for an 18 year period. Residual demand is expressed relative to the average annual residual demand over the full simulation. The red circles indicate rolling market demand response >= 5%, the black crosses show days with demand response greater than 1% .

APPENDIX 5: A TABLE OF KEY SIMULATION RESULTS

Table of key results in the 2 worlds without and with a SI 5TWh/1GW pumped hydro

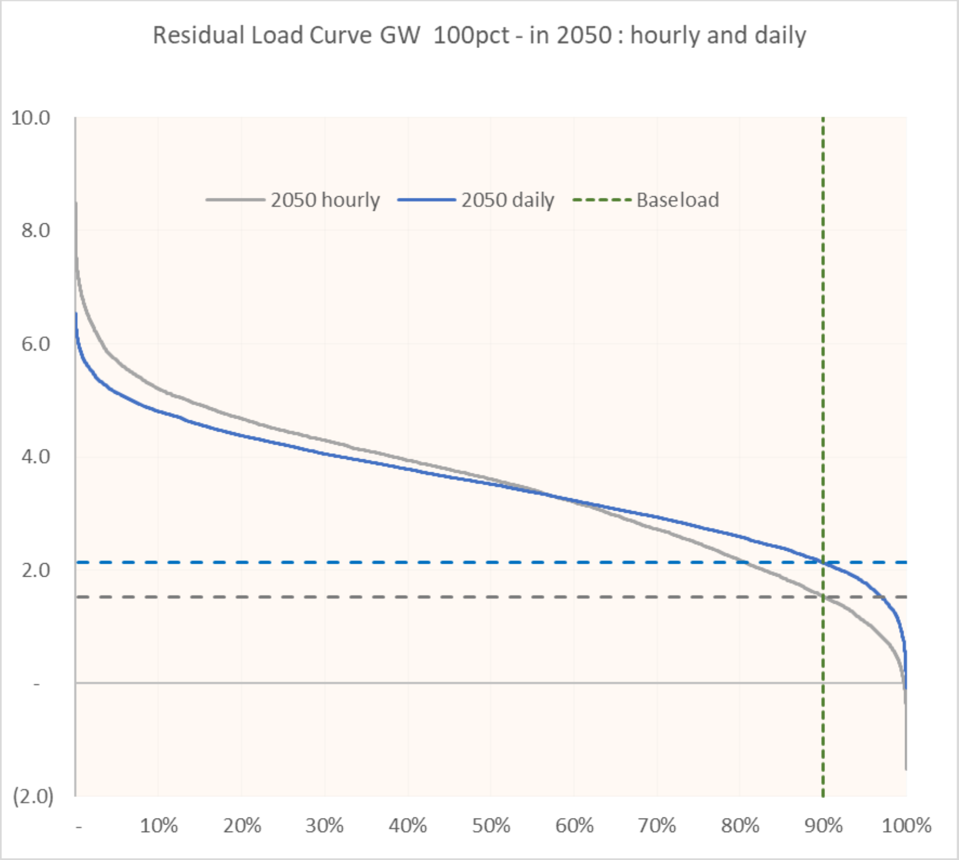
Summary results averaged over 86 weather years for each year of demand

		No NZ Battery 100% renewable					No NZ Battery Limited Thermal			SI 5TWh/1GW 100% renewable				SI 5TWh/1GW Limited Thermal		
		2020	2035	2050	2065	2065G	2035	2050	2065	2035	2050	2065	2065G	2035	2050	2065
Total Generation																
Geo	TWh	7.7	10.4	11.9	13.3	13.0	10.4	11.7	12.9	10.4	11.7	12.8	12.8	10.4	11.6	12.7
Wind	TWh	2.7	8.0	11.9	17.3	20.5	8.0	12.6	19.2	8.3	13.8	21.2	21.5	8.1	13.5	21.5
Hydro	TWh	21.5	20.4	20.4	20.1	20.7	20.7	20.8	20.8							
HydroRR	TWh	2.3	2.2	2.2	2.2	2.3	2.2	2.3	2.3	23.2	23.3	23.2	23.3	23.4	23.5	23.4
Cogen	TWh	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Thermal	TWh	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Peaker	TWh	1.9	0.0	0.0	0.0	0.4	0.3	0.5	0.7							
Reserve	TWh	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.1	0.2	0.2	0.3
Solar	TWh	0.0	2.0	5.2	10.6	6.8	1.3	3.9	7.9	1.5	3.5	7.0	6.7	1.3	3.5	6.6
Roof PV	TWh	0.2	1.6	3.0	3.9	3.9	1.6	3.0	3.9	1.6	3.0	3.9	3.9	1.6	3.0	3.9
Net Hydro Pumping	TWh	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.5)	(0.5)	(0.6)	(0.6)	(0.5)	(0.6)	(0.7)
Net Battery Energy	TWh	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Generation	**TWh**	**41.3**	**44.6**	**54.8**	**67.5**	**67.6**	**44.6**	**54.8**	**67.6**	**45.1**	**55.3**	**68.2**	**68.3**	**45.1**	**55.4**	**68.3**
Total Demand	TWh	41.1	44.3	54.5	67.2	67.2	44.3	54.5	67.2	44.3	54.5	67.2	67.2	44.3	54.5	67.2
Total Generation	TWh	41.3	44.6	54.8	67.5	67.6	44.6	54.8	67.6	45.1	55.3	68.2	68.3	45.1	55.4	68.3
Total Spill	TWh	0.6	3.8	5.6	10.5	7.1	2.8	3.9	6.3	1.7	2.3	4.4	3.3	1.3	1.6	2.7
Total Shortage	GWh	-	36	70	171	52	0	2	6	12	31	85	35	1	2	21
Pct generation renewable	**%**	**84%**	**100%**	**100%**	**100%**	**99%**	**99%**	**99%**	**99%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Pct Wind	%	7%	18%	22%	26%	30%	18%	23%	28%	18%	25%	31%	31%	18%	24%	31%
Pct Solar	%	0%	8%	15%	22%	16%	7%	13%	17%	7%	12%	16%	16%	7%	12%	15%
Pct Intermittent	**%**	**7%**	**26%**	**37%**	**47%**	**46%**	**24%**	**36%**	**46%**							
CO_2 Emissions	**mt**	**3.9**	**0.5**	**0.6**	**0.7**	**0.7**	**0.7**	**0.8**	**1.0**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.8**
Geothermal Emissions	mt	3.5	0.5	0.6	0.7	0.7	0.5	0.6	0.6	0.5	0.6	0.6	0.6	0.5	0.6	0.6
Thermal Emissions	mt	0.4	0.0	0.0	0.0	0.0	0.2	0.3	0.4	0.0	0.0	0.0	0.0	0.1	0.1	0.2
Fuel Use PJ	PJ	46.6	0.0	0.0	0.0	4.2	3.5	4.7	6.5	0.0	0.0	0.0	1.5	1.6	1.9	2.8
Total Capacity																
Geo	GW	1.0	1.3	1.5	1.7	1.7	1.3	1.5	1.6	1.3	1.5	1.6	1.6	1.3	1.5	1.6
Wind	GW	0.8	2.8	4.5	7.3	7.5	2.6	4.3	6.9	2.5	4.2	7.0	6.8	2.4	4.0	6.7
Hydro	GW	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
HydroRR	GW	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Cogen	GW	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal	GW	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaker	GW	0.5	0.0	0.0	0.0	0.8	0.7	0.9	1.4	0.0	0.0	0.0	0.4	0.6	0.6	0.6
Solar	GW	0.0	1.1	2.9	5.9	3.8	0.7	2.2	4.4	0.8	1.9	3.9	3.7	0.7	1.9	3.6
Roof PV	GW	0.2	1.3	2.5	3.2	3.2	1.3	2.5	3.2	1.3	2.5	3.2	3.2	1.3	2.5	3.2
HydroPump	GW	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Grid Battery 4-12hr	GW	0.0	0.2	0.2	0.6	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.1	0.1	0.3
EV Load Shifting	GW	-	0.2	0.6	1.1	1.1	0.2	0.6	1.1	0.2	0.6	1.1	1.1	0.2	0.6	1.1
Rooft Top Battery	GW	-	0.4	0.8	1.0	1.0	0.4	0.8	1.0	0.4	0.8	1.0	1.0	0.4	0.8	1.0
Demand Response	GW	0.4	0.6	0.8	1.0	1.0	0.6	0.8	1.0	0.6	0.8	1.0	1.0	0.6	0.8	1.0
Total Capacity	**GW**	**8.8**	**13.0**	**18.8**	**27.0**	**25.3**	**13.2**	**18.8**	**25.9**	**13.4**	**18.5**	**25.2**	**25.2**	**13.8**	**18.9**	**25.2**
Demand management & Batteries	GW	0.4	1.3	2.3	3.7	3.2	1.3	2.3	3.2	2.3	3.3	4.3	4.2	2.3	3.2	4.4
as % total capacity	%	5%	10%	12%	14%	13%	10%	12%	12%	17%	18%	17%	17%	16%	17%	17%
Geothermal Investment	GW		0.3	0.5	0.7	0.7	0.3	0.5	0.7	0.3	0.5	0.7	0.6	0.3	0.5	0.6
Wind Investment	GW		2.0	3.7	6.6	6.7	1.9	3.5	6.2	1.7	3.5	6.2	6.0	1.6	3.3	5.9
Grid Solar Investment	GW		1.1	2.9	5.9	3.8	0.7	2.2	4.4	0.8	1.9	3.9	3.7	0.7	1.9	3.6
Rooftop Solar Investment	GW		1.2	2.4	3.1	3.1	1.2	2.4	3.1	1.2	2.4	3.1	3.1	1.2	2.4	3.1
Total renewable investment	**GW**		**4.6**	**9.5**	**16.3**	**14.2**	**4.1**	**8.5**	**14.3**	**4.1**	**8.2**	**13.8**	**13.5**	**3.9**	**8.1**	**13.2**
Wind	CF after spill	40%	32%	31%	27%	31%	35%	33%	32%	38%	37%	35%	36%	39%	38%	37%
Grid Solar	CF after spill	20%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%
Rooftop Solar	CF after spill	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
Wind Spill	% of Supply	0%	19%	24%	32%	22%	14%	17%	21%	6%	8%	13%	9%	4%	5%	7%
Pumped Hydro Gross CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	15%	17%	19%	22%	17%	20%	23%
Pumped Hydro Pumping CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	20%	23%	26%	29%	22%	26%	30%

APPENDIX 6: AN ALTERNATIVE ANALYSIS OF THE CHANGING NEED FOR FLEXIBLE BACK UP - FOCUSING ON RESIDUAL DEMAND AFTER INTERMITTENT SUPPLY

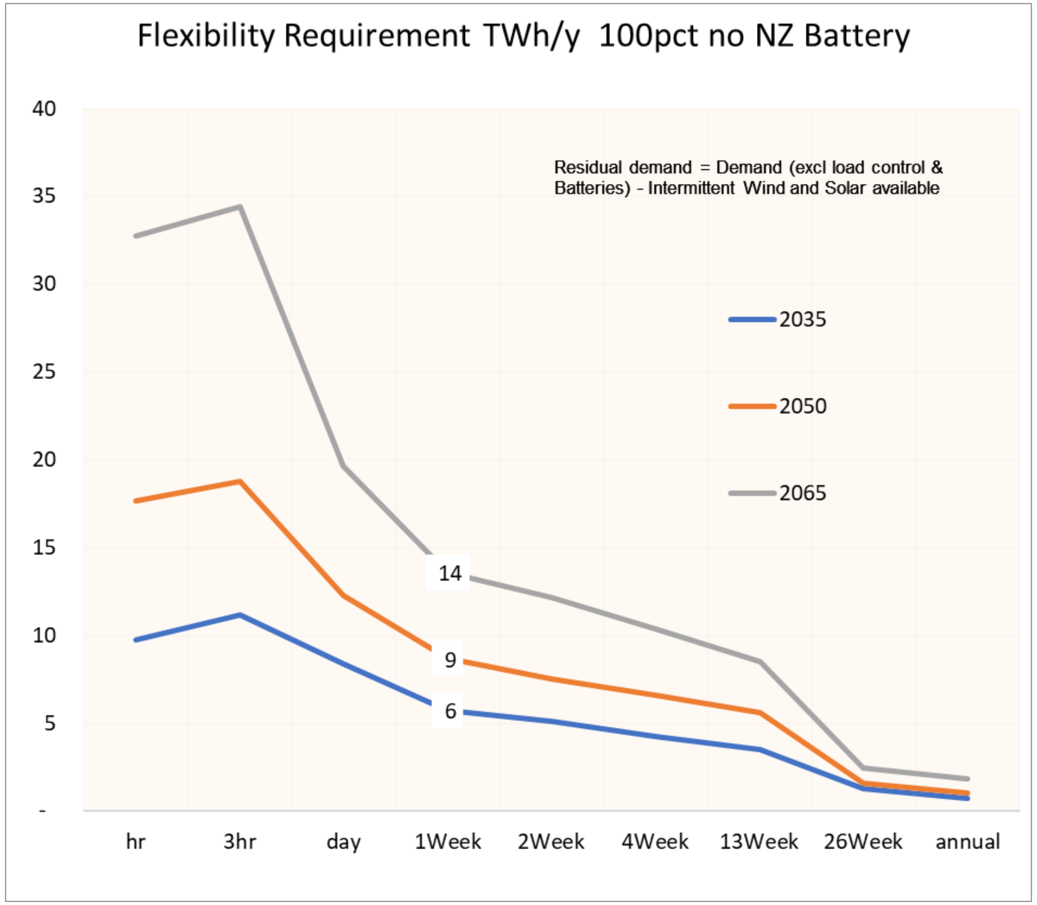
We have also used the shadow model to explore how the need for flexible energy changes over time

- To illustrate the changing need for flexibility as the system grows in a 100% renewable world, we calculated the variability of residual demand
- Residual demand is demand above a “base load” level that must be met by flexible generation (proxied in the chart as the level above 90%)
- In the example shown, the hourly flexible residual demand requirement is the area between the two blue lines
- This can be assessed across different time frames - daily is also shown
  - Daily uses the same approach, but the average residual demand for each day is used instead
  - The resulting area between the two curves is lower, reflecting that the variation between days is lower than between hours



Residual demand variability

- We repeated the steps in the previous slide for a wide range of different time periods, and across our three modelled years
- The results are shown alongside and some things are apparent:
- Residual demand variation increases from 2035 to 2065
  - The increase from 2050-2065 is larger than the increase from 2035 - 2050
  - The increase is most stark for time periods less than a day
  - This reflects the ever increasing proportion of wind and solar generation, which begin to outweigh underlying demand variability
- There is minimal difference at a yearly level (but this analysis excludes hydro inflow variation, see next slide)



Residual demand variability

- The previous slides showed residual demand excluding controlled hydro generation.
- Shown here is the residual demand after controlled hydro generation.
  - Controllable hydro “flattens” the curve
  - It lowers residual demand variability over shorter time periods, reflecting the ability of hydro to sculpt generation into peaks
- Note that the effect of variation in hydro inflows and spill is not included here.
  - This is explored in the main section of the report covering the changing nature of dry year and capacity backup issues.