Power without the carbon?

The future of the NZ power system
with 100% renewables

Grant Telfar

Living in uncertain times: renewable energy & dry year flexibility

The Government has stated its intent for a 100% renewable system by 2030:

- They are proposing the Onslow-Manorburn pump storage scheme as a key plank towards this goal
- Newly committed wind and geothermal projects (2.7TWh) will move the system to 90% renewable over the next few years

Hydro inflow deficits of 5TWh annually have historically been managed by maintaining thermal capacity, flexible thermal fuel storage, and flexible thermal fuel deliveries:

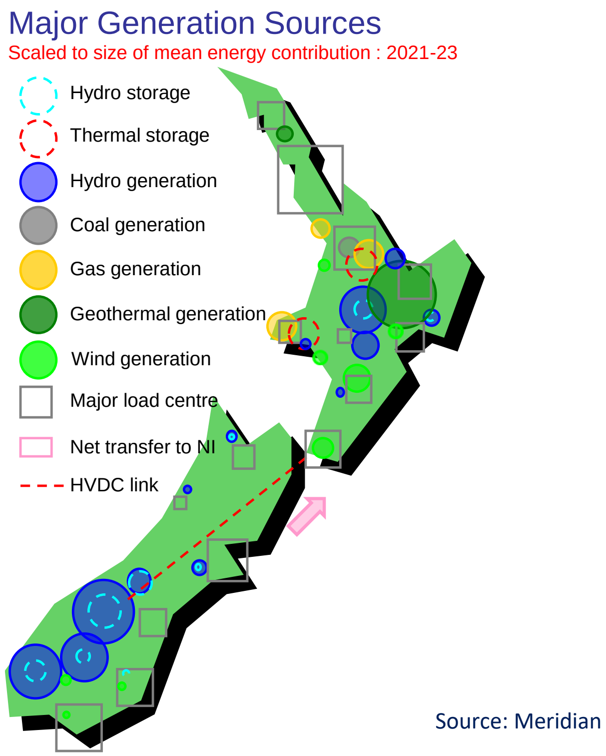
- As more wind enters the system, it too can face extreme annual deficits of 8-10%. Solar also faces annual deficits of up to 3-5%

A Tiwai smelter closure by the end of 2024 could see 5TWh of excess Southland-Otago generation attempting to flow northward creating a regional energy imbalance:

- In response, large-scale demand stimulation projects are being pursued

The retirement of NI thermal plant is both a problem to be solved but also a unique opportunity to move faster towards a 100% renewable power system, and a range of solutions beyond Onlsow has been proposed to help transition the power system towards 100% renewable:

- Renewable overbuild,
- Increased hydro flexibility,
- Demand response,
- Progress as far as 95-98% renewable and leave gas peakers in,
- Thermal-co / thermal reserve schemes, 99% renewable.

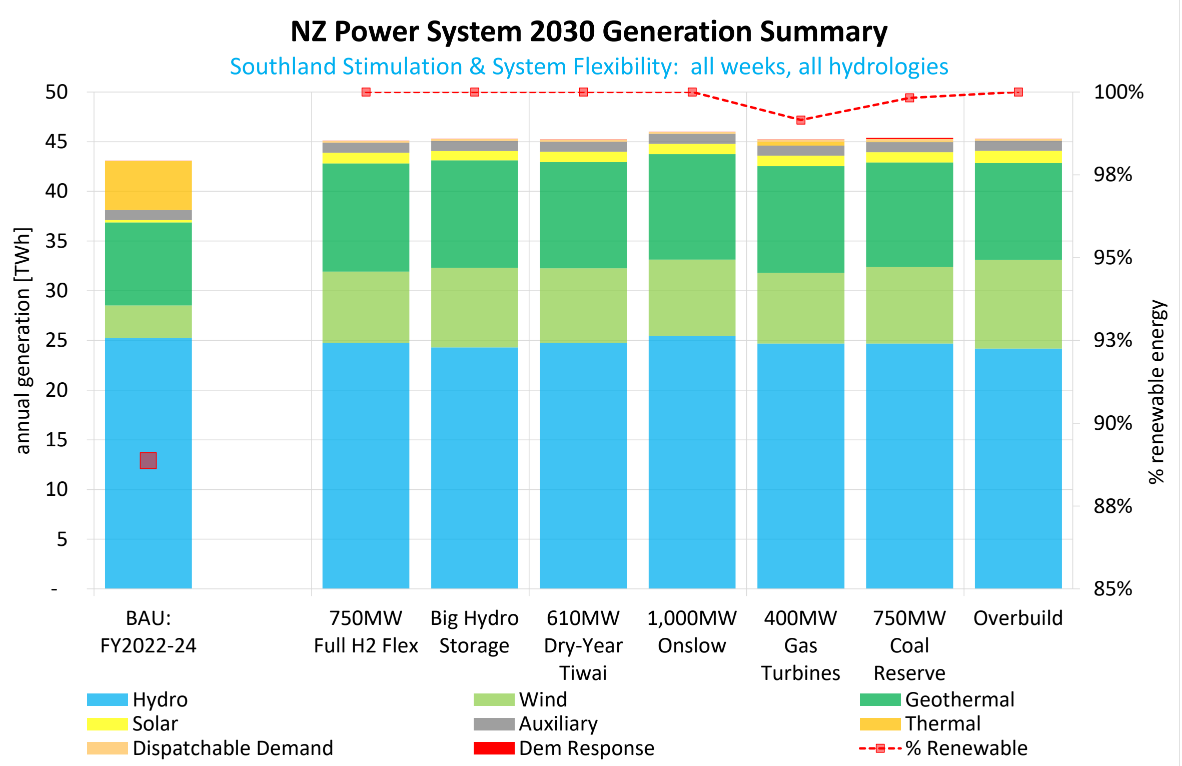


Source: Meridian

Significant new demand in Southland that is also flexible could address regional energy imbalance and create an alternative mechanism for dry-years

Changes to the power system by 2030

- Significant new renewable energy (RE) generation is needed: 12TWh, 3GW, and $7B of new *grid* generation:
  - Modest demand growth = 2,500GWh
  - Thermal retirement = 6,500GWh
  - Renewable replacement = 3,000GWh
  - New decarbonised load = ??? GWh
- A secure power system can be delivered in different ways: including demand-side, hydro, thermal, and overbuild:
  - All rely on other power system components flexing: hydro capacity, dispatchable demand, renewable spill, BESS, ...
  - Any of these solutions can do the job: delivering a secure power system with low carbon emissions and a high level of RE
  - Costs of some solutions, cost allocation, and implications for market design are more challenging for some solutions
- The pace of change and sheer scale of this challenge is enormous, regardless of the solution to dry-year flexibility:
  - Wide-reaching changes are expected: storage, prices, and generation all alter dramatically from today's expectations



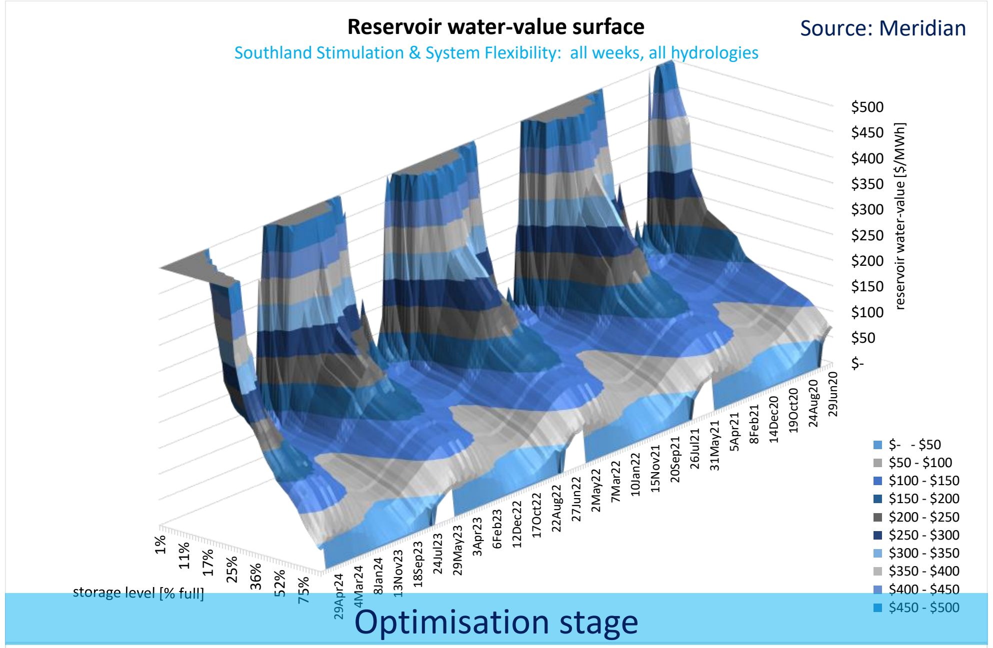
There is a range of valid ways a secure future power system with low emissions could be delivered:

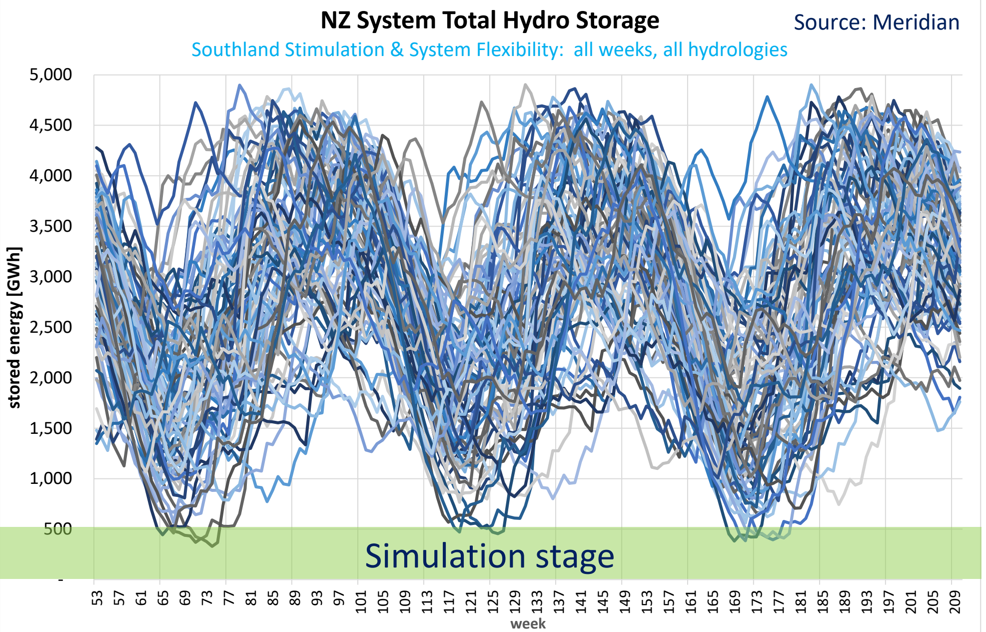
- Demand-side solutions
- Hydro solutions
- Thermal solutions
- Overbuild solutions
- A combination of the above

Analysing the future

- We use 'LPcon' to represent the current and future state of the power system
- LPcon is a two-stage, hydro-thermal optimisation and simulation analytical model of the NZ power system:
  - Stochastic reservoir optimisation: produces multidimensional option values for water = reservoir operating rules.
  - Power system simulation: given reservoir operating rules, produces multiple forecasts of future system performance.
- Most key aspects of the power system are represented:
  - Supply & demand, transmission, thermal & carbon costs, flexibility, storage, inflow, wind, & solar uncertainty, intermittency, climate change, reserves, frequency, uncertainty, new build project details, financial cost information.
- LPcon balances the costs of excess renewable spill, energy and reserve costs, against excess system shortage:
  - Power supply costs are minimized for NZ – in the face of uncertain supply
  - Balancing appropriate use of storage and minimising new build costs

Details matter : quantifiable, rigorous, well-defined, testable, and repeatable methodologies are key

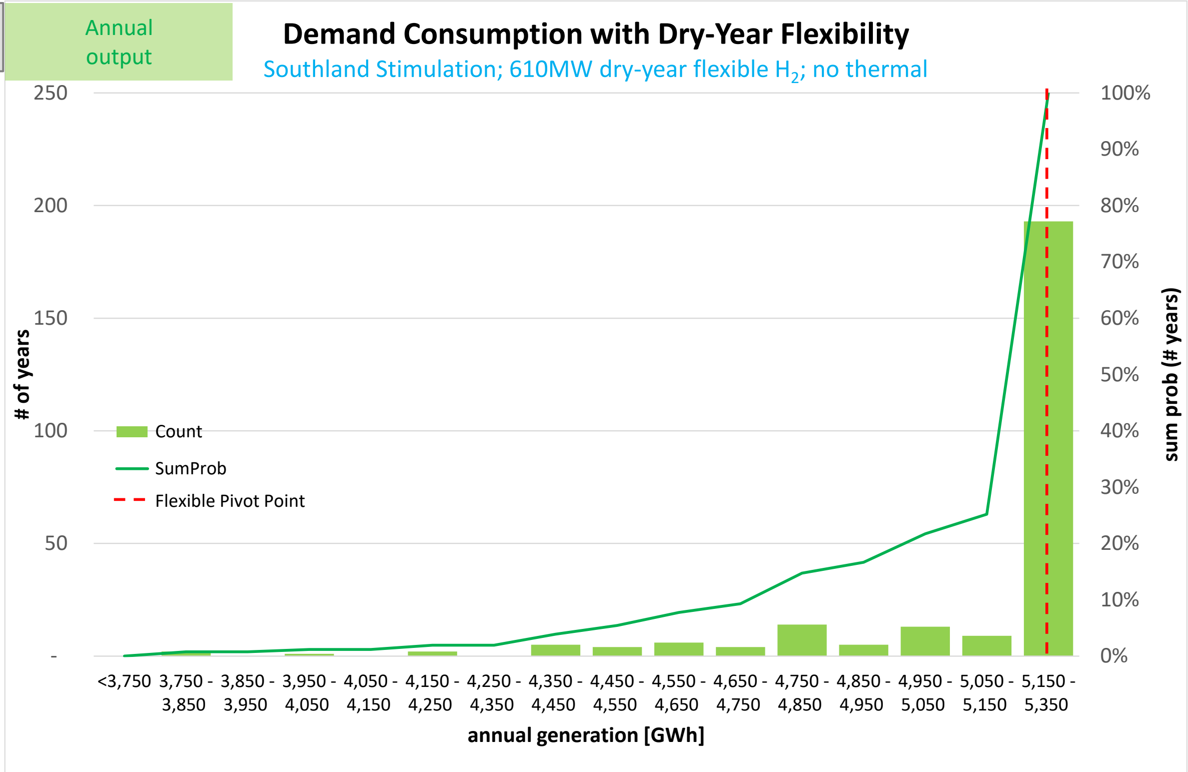




Future dry year flexibility scenarios – i

610MW Southland demand

- This could either be new or existing demand
- Flex production down in times of hydro inflow scarcity, and falling lake levels, in incremental steps
- Across all hydrological history, demand reduction is low 250GWh pa (5% of annual production)
- This can vary between 0 and 1,500GWh (30% of production) with the extreme occurring infrequently, <1% of all inflow years
- No flexibility at all is required in up to 75% of all hydrological years
- On rare occasions of extreme stress, the market could consume the entire load of the facility (610MW) for a number of weeks or even months



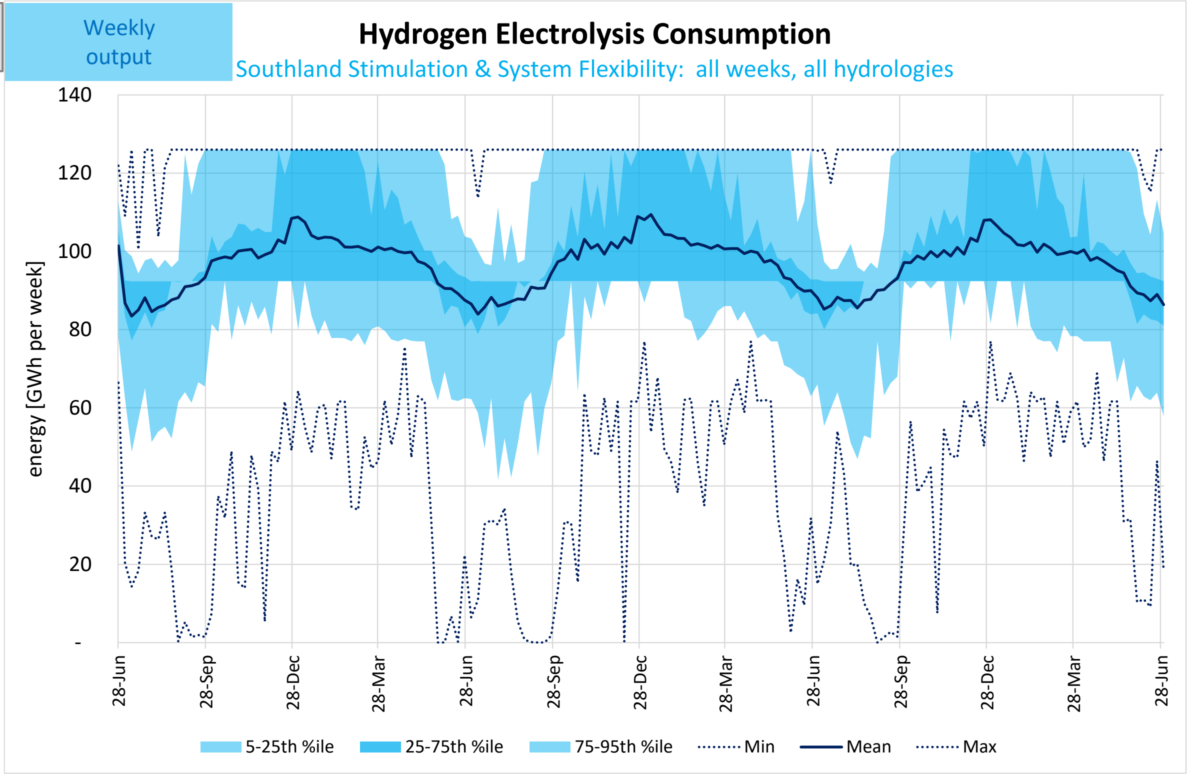
Source: Meridian

The need for flexibility in large scale demand is modest but with some extreme usage seen in rare, dry years

Future dry year flexibility scenarios – ii

750MW hydrogen electrolysis plant

- As per scenario #1, flex production *down* in times of hydro inflow scarcity in incremental steps
- Adding to this*:* flex production *up* in times of renewable surplus: wet, sunny, windy, low demand, …
- A "typical" running load of 550MW
- The ability to increase to 750MW during periods of surplus at lower market prices
- Annual consumption the same as previous case (5TWh), a 77% capacity factor, with dry-year flexibility offered back to the power system, up to 1.5TWh
- Strong seasonality in the demand for flexibility is seen
- The distribution of potential H_2 plant loading is far broader than was observed for dry-year demand response only



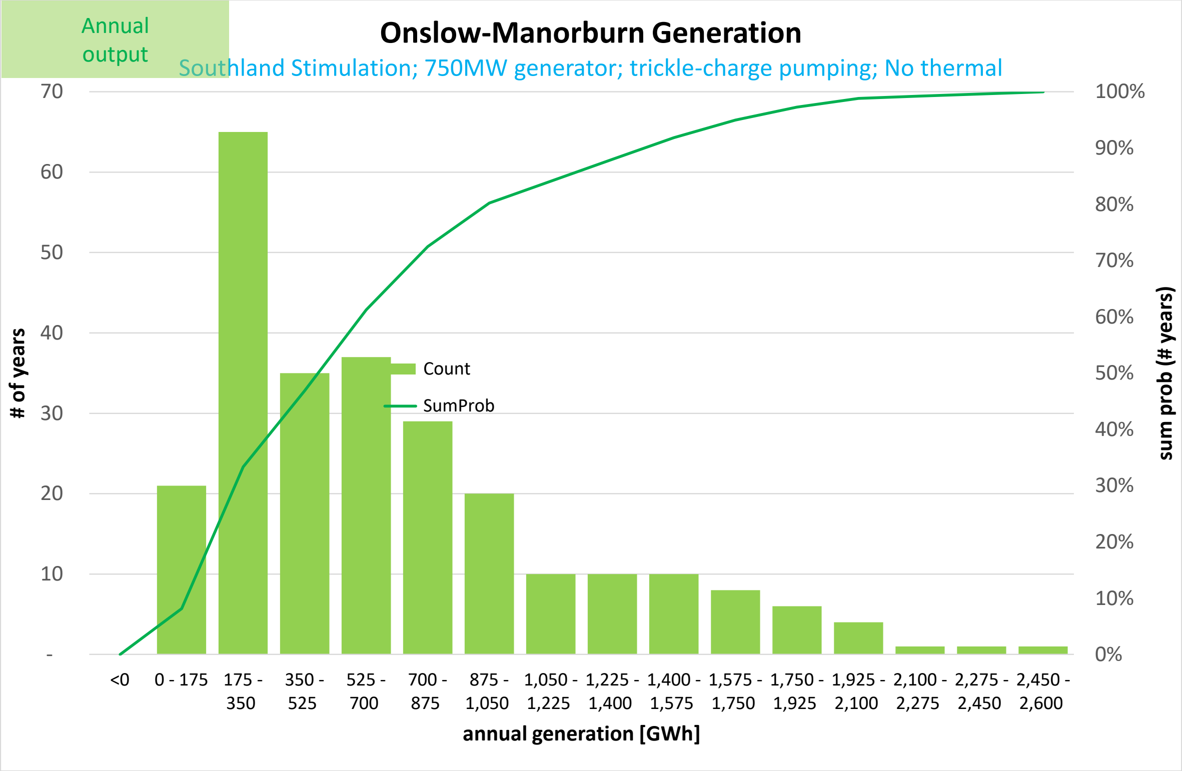
Source: Meridian

Benefits to the system can be significant: increasing the overall power system capacity factor, dry-year management, and the ability to absorb more intermittent renewables

Future dry year flexibility scenarios – iii

(simple) Onslow-Manorburn pumped storage

- 585MW of (new or old) Southland load with no flexibility
- A simple 4,000GWh storage and 1,000MW power station scheme:
  - 25% losses: 750MW available for hydro management and 250MW for intermittency management
- Reservoir release rules determined by dynamic needs of the power system, dispatched according to water-value:
  - Mean dry-year pumping load is 650GWh – 'trickle charge' overnight in summer
  - Mean generation / releases are ~525GWh. Intermittency management contributes an extra ~125GWh
  - There is a clear seasonal need for generation
  - In extremes, up to an extra 1,750GWh of generation is dispatched back into the market

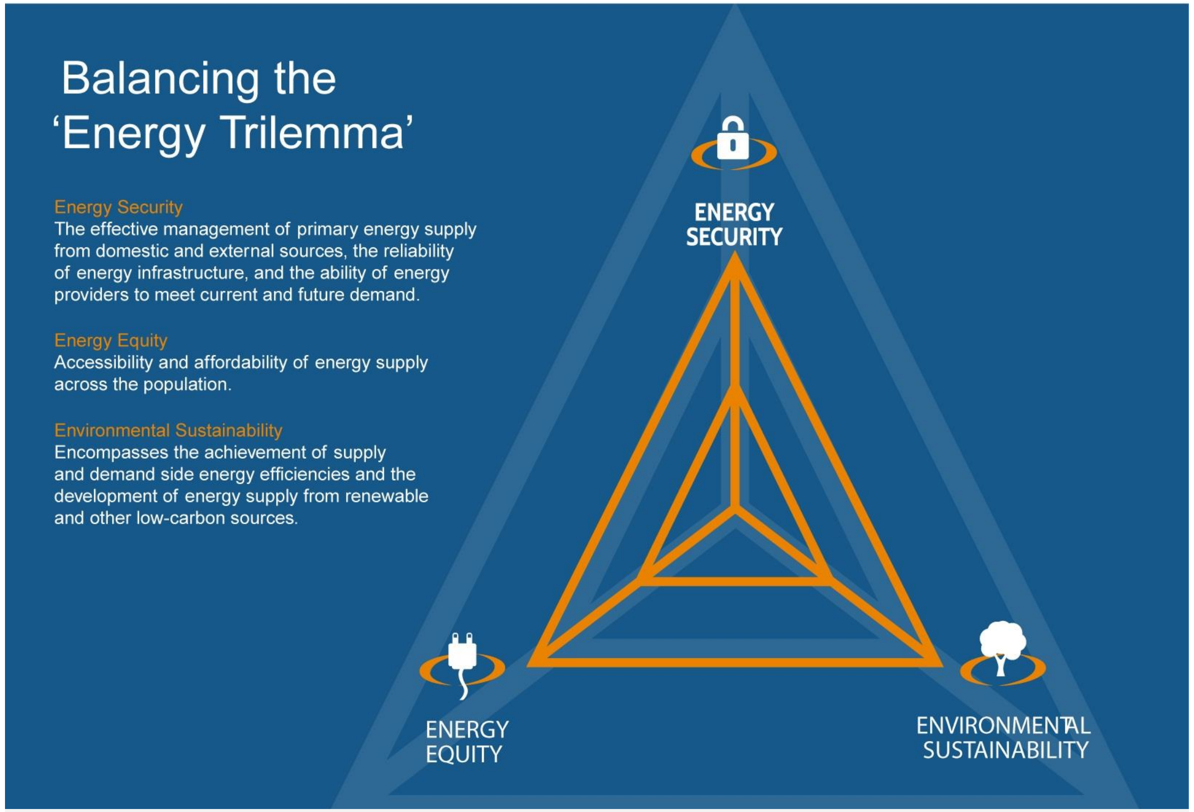


Source: Meridian

The $4B+ Onslow scheme can be a viable dry year mechanism, along-side other sources of flexibility

How to measure good?

- Cost is not the only metric for New Zealanders (the Government, regulators, investors) to consider when thinking about future outcomes:
    - Carbon, sustainability, security, volatility, and investment/market stability are all important
    - Trade-offs are often inherent in any comparison
    - Avoid throwing the baby out with the bathwater
- The World Energy Council's energy trilemma is a useful framework to contextualise this:
    - 3 needs (axes) to balance
    - *How* the balance is maintained is also important

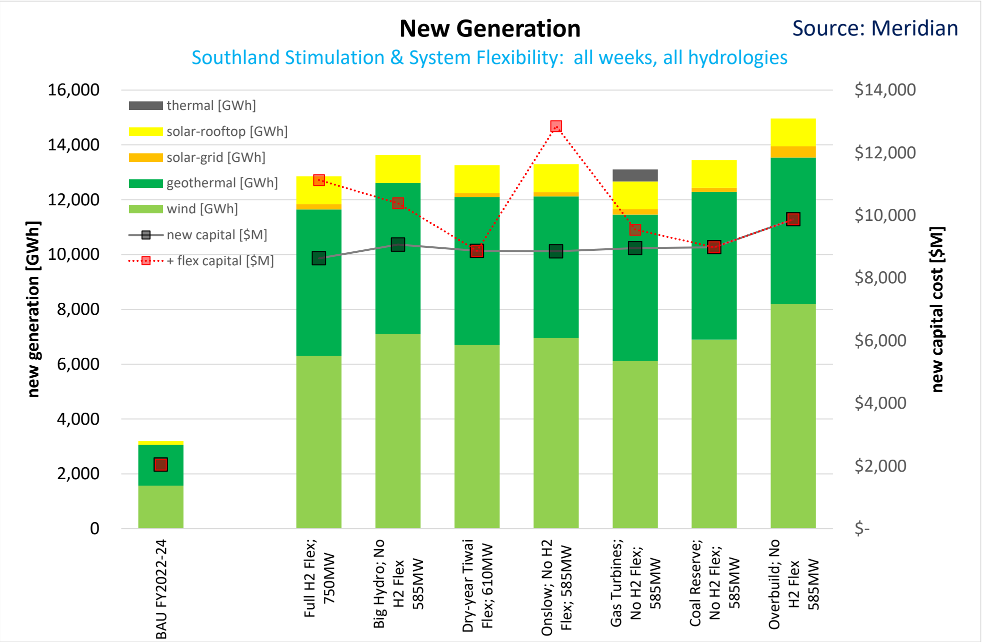


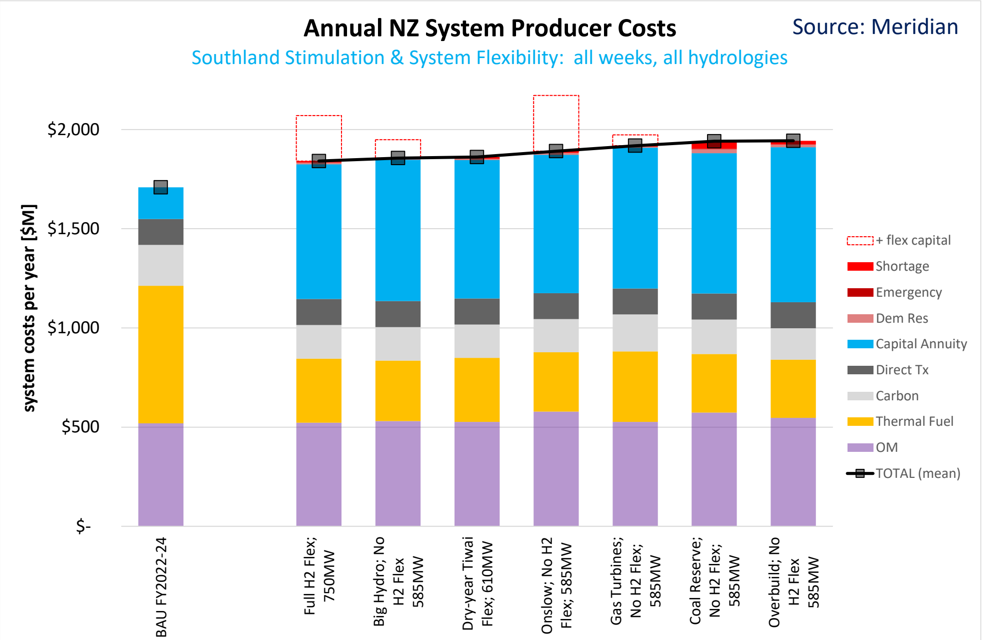
Trying to improve <u>and</u> balance *all* needs

Balancing occurs via well regulated, energy-only, efficient market mechanism and supporting policy

Annual system (producer) costs by 2030

- Over the decade, the challenges of meeting the generation needs of a power system moving towards 99-100% RE are significant:
    - 13-15TWh of new generation, including roof-top PV
    - new capital requirements are broadly in line with energy needs
    - \$9.5-10B (including \$1.9B of roof-top PV)
- System costs (grid-level producer costs) are modestly higher than today; a \$100M difference between best & worst case
- But *additional* capital costs are likely for new flexibility:
    - H_2 = \$2.5B; Onslow = \$4B; gas flexibility = \$0.5B; big hydro flexibility = \$1.5B
    - Depending on how costs are socialised, dry-year load response or hydro solutions could all be cheapest
    - *But* the additional capital costs of flexibility (red lines) changes this conclusion
- System costs are not the only metric for the Government to consider: all trilemma needs are important



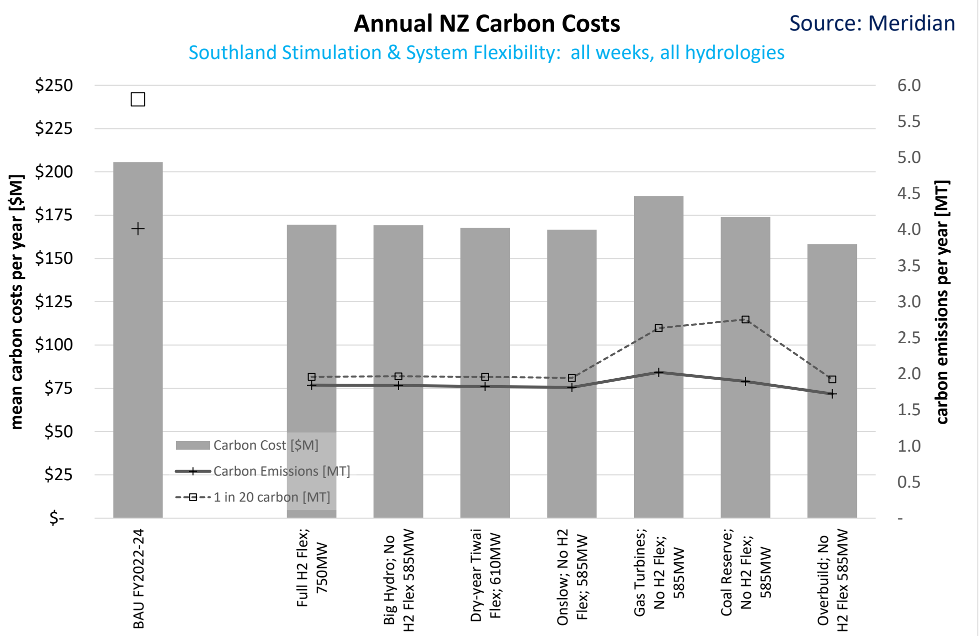


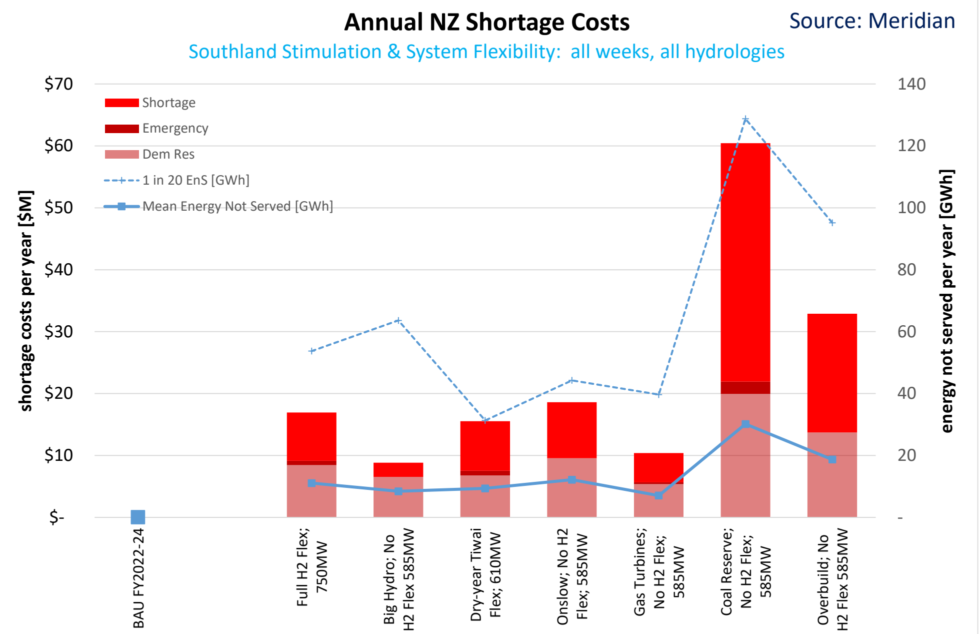
A tight range of system costs is seen between quite the solutions – *Until* the unknown costs of flexibility are considered

Other outcomes: carbon and shortage

- CO_2 emissions in a highly RE power system are broadly similar regardless of the dry-year solution:
  - 100% renewable <> 0MT of emissions
  - < 2MT, down from 5MT in recent years
  - Gas & coal solutions only increase emissions modestly, even in dry-years
  - Annual emission costs could be significant, at $170M
- Shortage is a measure of economic cost to the economy resulting from prolonged supply interruption:
  - NZ has had no hydro related shortage since 1992
  - We expect no hydro shortage in the near-term
  - The future system has shortage levels determined by commercially-led new investment, storage management, and the intermittency of new generation
  - All scenarios show non-zero, but low levels of average and extreme interruption
  - (NI) intermittency begins to create challenging outcomes in extremes

There is no such thing as a perfect power system –
Shortage levels are reasonable, except when intermittency dominates





Establishing the 'best' NZ outcome

- There is no single solution to dry-year flexibility that produces a desirable outcome measured against all trilemma metrics
- A compromise outcome is required – this is not an exact science
- Of the solutions explored for the 2030 NZ power system:
  - Either of the flexible demand response solutions or either of the hydro solutions can achieve good combined outcomes
  - The additional costs of flexibility may change this view
  - Thermal solutions or system overbuild fare less well
- Flexible demand response, especially if it can manage dry-years *and* intermittency, represents a fantastic opportunity
- A market facing arrangement (rather than a reserve scheme based on storage or other triggers) presents a better outcome for NZ
- Solutions do not need to be mutually exclusive. There is a role for multiple solutions to work happily alongside each other in a complementary fashion

Ranking of Dry-Year Flexibility Solutions

wgt		H2 full flex market	Big Hydro market	Dry-year Dem Res market	Onslow market	Gas Turbines market	Coal Reserve reserve	Overbuild market
9%	Generation Capital Costs	1	6	3	2	4	5	7
9%	+Flexibility Capital	6	5	1	7	3	2	4
9%	Prices (LWAP)	4	4	3	1	1	6	7
5%	Price Volatility	2	1	2	2	2	7	6
5%	Hydro Storage Buffer	5	2	5	1	4	5	3
12%	Operating Costs: Average	2	1	2	5	6	7	2
6%	Operating Costs: Extremes	3	1	4	1	6	7	5
18%	CO_2 Emissions	2	2	2	2	7	6	1
18%	Shortage	3	1	4	5	2	7	6
5%	RE Spill: Average	2	6	3	1	5	4	7
2%	RE Spill: Extreme	3	6	4	2	1	5	7
2%	Wind & Solar Spill	2	3	4	5	1	6	7
2%	Geothermal Spill	2	3	5	1	4	6	7
100%	**Weighted Score**	**2.8**	**2.7**	**2.9**	**3.2**	**4.0**	**5.8**	**4.5**

Undesirable
Desirable

Source: Meridian

Better combined dry-year flexibility solutions

The best source of future dry year flexibility

- The scale and pace of change required to move the NZ power system to 100% renewable energy is significant
- Changes expected in wholesale market outcomes and performance will be dramatic at times:
    - Mean modelled prices ~$80/MWh in most scenarios, but sufficient to generate a return on investment
    - Weekly price volatility – especially in winter – is significantly higher than seen today (4-5x)
    - Storage levels are held higher, creating a buffer against deficits in renewable fuel
    - Expected carbon emissions are low in all cases: but slightly higher for coal and gas solutions
    - Expected shortage is greater than today's market but manageable – if market behaviour aligns to need
    - Significant renewable energy spill (wind, geothermal, solar) adds to the hydro spill seen in today's market
- There is no single solution to future dry-year flexibility that produces a desirable outcome in all situations
- Of the solutions explored, either of:
    - Flexible demand response solutions – especially if they can manage both dry-years and intermittency; or
    - Expanded hydro flexibility and/or storage solutions – assuming no consenting or constructability concerns;

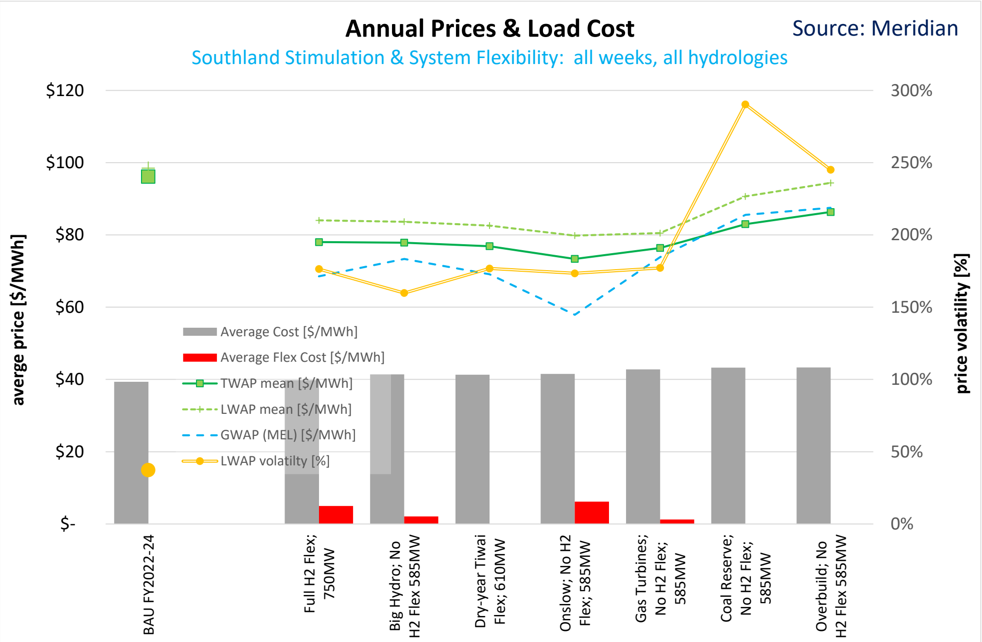
  … can achieve a good balanced compromise of power system outcomes across a range of metrics
- All dry-year solutions explored have the potential to help solve much of the NZ dry-year issue
- Any given solution does not need to solve the issue in its entirety

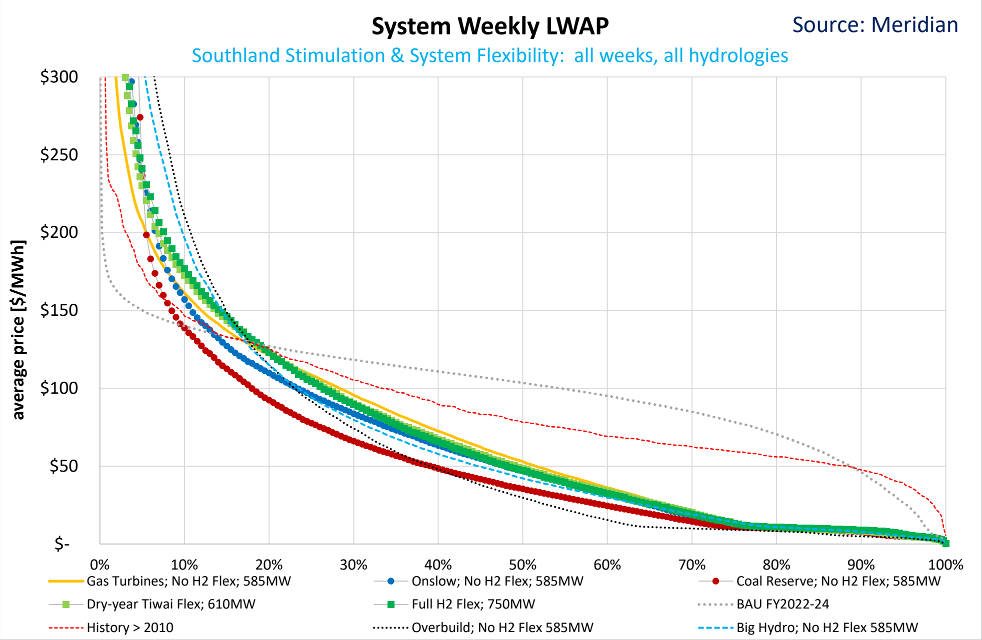
Additional material

Power system performance compared across scenarios

Market prices and load costs

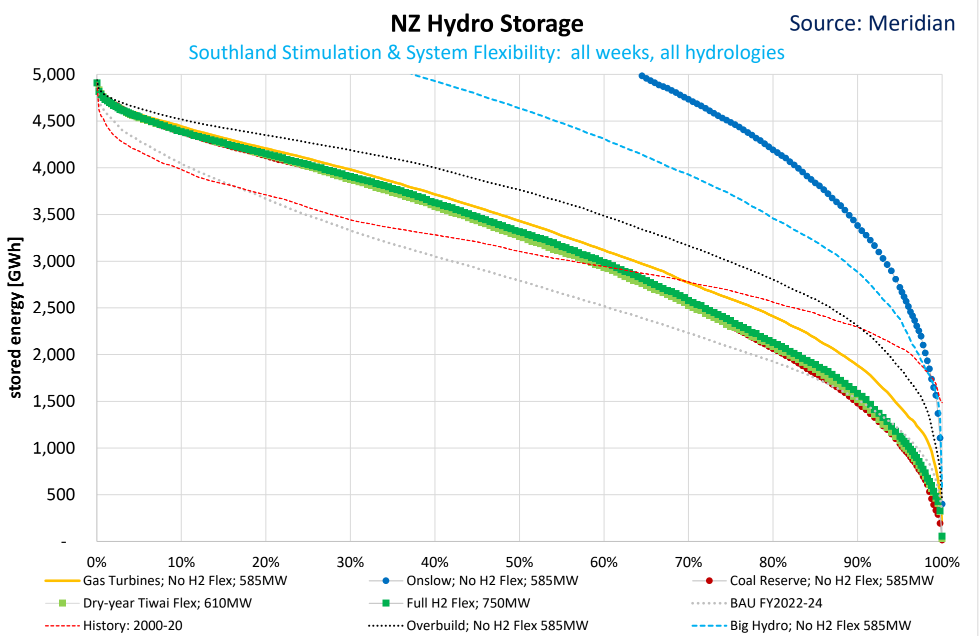
- Marginal prices and system costs – at mean – are modest, reflecting falling LCOE, and are sufficient to generate a return on generation investment
- Price volatility is *dramatically* higher than today, more than tripling in scale
- As we move towards higher levels of RE, the nature of marginal pricing changes significantly and the shape of prices changes markedly:
  - Seasonal pricing shows significant winter stress
  - The full price distribution (across all hydrological outcomes and all seasons) shows prices close to zero for significant periods, 30-40% of the time
  - Prices at peak and at times of system stress are likely to be very high with no-or-little thermal generation available to regulate
  - System price peakiness is made worse for any ring-fenced reserve scheme solution
- We expect to see significant changes to market price behaviour, but the differences *between* the scenarios are smaller:
  - The nature of pricing is determined more by the makeup of the highly RE power system and less by the dry-year solution for flexibility
  - Subtle but important differences for peak prices can also be seen

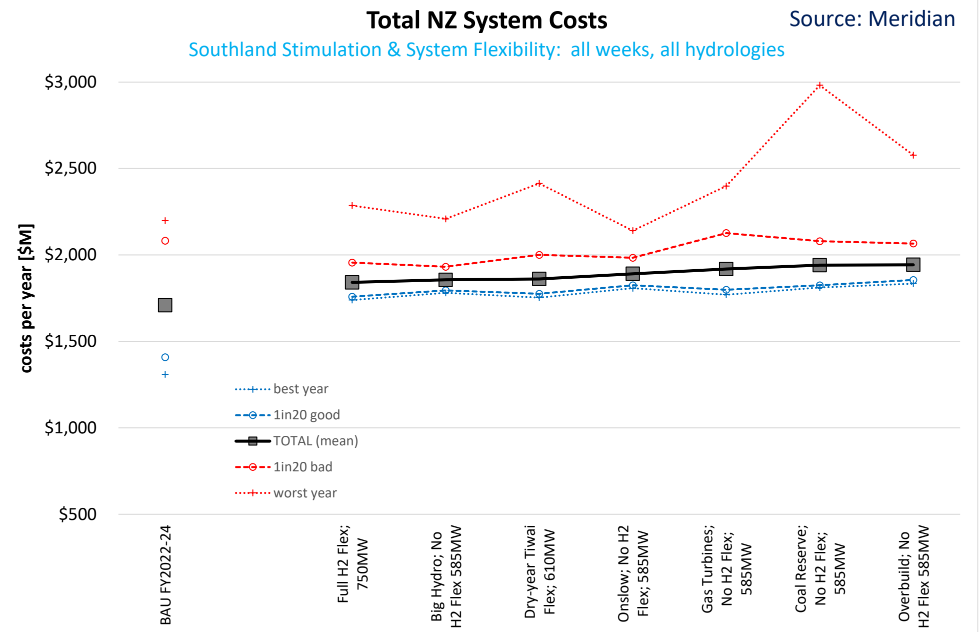




Hydro storage and management

- The management of *existing* hydro storage changes only modestly as the thermal contribution to the power system decreases:
  - We assume a risk averse approach to storage management in all cases
  - The seasonality of average storage management remains
- Storage for existing reservoirs is held higher than today, creating an “insurance buffer” for dry-years & helping manage periods of low intermittent generation:
  - The full consented storage range is still needed in extremes
  - A larger hydro storage system brings with it higher average storage
- Storage use for *existing* reservoirs is similar regardless of dry-year solution:
  - Optimal use is dynamic and determined by the nature of the power system
  - As the level of RE generation increases, so do lake levels
- Similar storage outcomes, increased price volatility, and similar new capital requirements are associated with small changes in average annual system costs:
  - (ignoring additional capital costs of new flexibility) examining the full range of hydrological outcomes does show differences in total system costs
  - For dry years, the most expensive outcomes occur for thermal and overbuild solutions





Hydro spill and other RE spill

- RE spill is only modestly affected by the solution to dry-year flexibility:
  - The exception being the overbuild scenario
  - In wet extremes, the gas turbine solution shows reduced spill
- RE spill is dominated by hydro with wind (and solar) small but growing
- Geothermal 'spill' is not technically spill – it is simply geothermal generation that does not generate due to market prices in times of surplus being lower than the marginal costs of carbon emissions:
  - Carbon costs are in the order of $5-10/MWh for a $100/t CO_2e price
  - Expected levels of geothermal spill are moderate at 12-25% of baseload output – all new geothermal plant are still assessed as being revenue adequate
  - Non-zero emission factors will likely mean that geothermal generation will depart from being a pure baseload renewable energy source