meridian

Market Performance: 2010-2017
A Meridian Hindcasting Perspective

Lessons to be learnt from
looking in the rear-view mirror

Strategy and Performance, Sep 2018

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Hindcasting Introduction

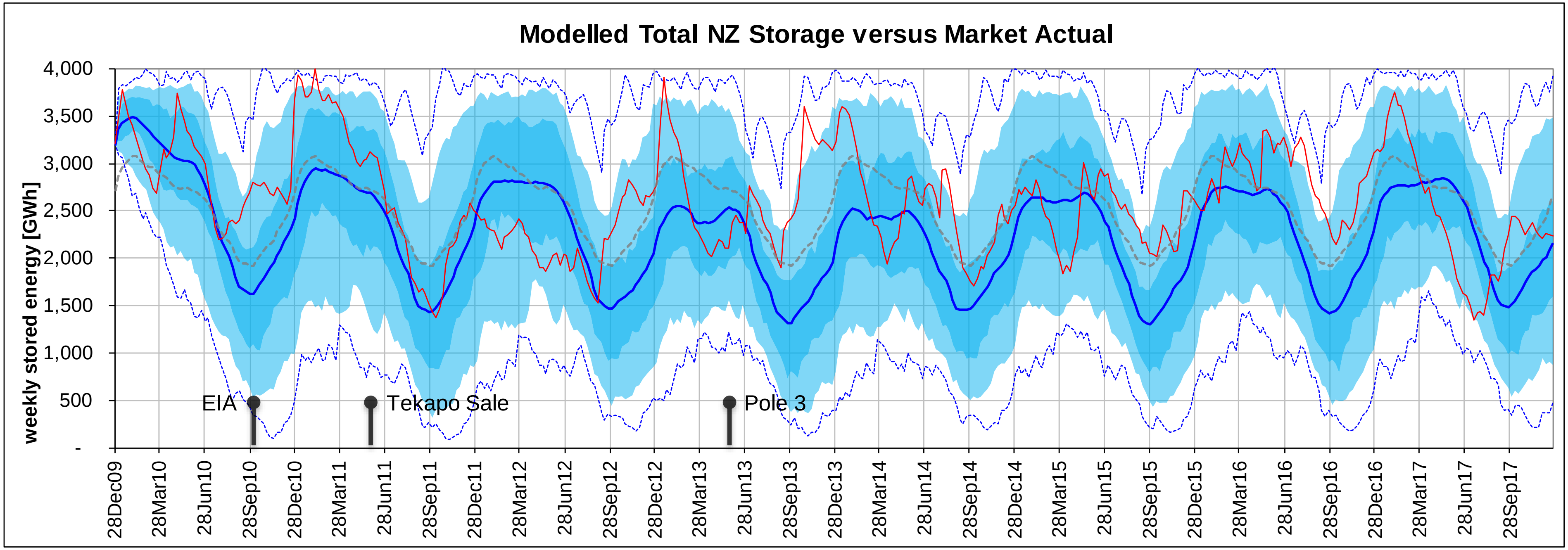
- Hindcasting is a best practice analytical approach applied to examine how decision support tools, analysis, and key assumptions perform after the fact.
- Meridian uses a common toolset for a range of internal purposes, including:
  - Operational risk management.
  - Balance sheet valuation.
  - Regulatory insights.
  - Bespoke investigations.
  - Customer contracting decisions.
- Meridian needs a robust approach to meet internal and external performance, assessment, and self-examination requirements:
  - To test quality of internal decision support.
  - To understand what regulatory perspectives might look like.
- Meridian has undertaken a number of hindcasting exercises over the last 10 years.
- Here we re-examine the eight year period covering 2010-2017 to refresh our own thinking. This is particularly timely in terms of “how well has the market been doing” in anticipation of:
  - The usual internal and continual process of self-assessment.
  - Electricity Price Review.
  - ICCC and energy-sector decarbonisation goals.
  - Emissions Trading Scheme review.

Hindcasting Methodology

- We configure our power system model (LPcon – see description at back) to reflect the fundamental constraints and underlying costs of electricity supply and demand in NZ:
  - Allowing for the underlying annual costs of running the power system (fuel, O&M, et al) subject to usual array of operational constraints.
  - NOT a re-litigation of the market's operational decisions on the day.
- LPcon is used as a proxy regulatory benchmark:
  - A two-stage hydro-thermal optimisation and simulation model of the NZ power system.
- We first examine the key residual energy problem in NZ: the hydro-thermal reservoir management problem:
  - Conventional and well understood conceptually.
  - For this exercise:
    - Demand, geothermal & co-gen output, plant outages and running costs are all assumed to be fully known as occurred in the real world.
    - Hydro and wind are assumed to be unknowable.
    - Thermal and hydro offer behaviours are assumed to be simple and cost-reflective.
- Beginning in January 2010:
  - Optimise the use of water in storage in the face of historical hydrological and wind uncertainty – all weekly inflows and wind records over the 1932-2017 period – to create water-values.
  - Run the model once to simulate the 8 year 2010-2017 period for all hydrological sequences.
  - Examine the single inflow sequence corresponding to actuals.
  - Compare modelled benchmark results to actual market outcomes.
- Once we have assessed how much inflows and simple thermal offers influence storage behaviour and market prices we can consider uncertainties and definitional issues in other aspects of the wider power system problem:
  - Seasonal demand, outages, fuel and carbon costs, O&M decisions and costs, competitive offering behaviour, risk aversion, etc…

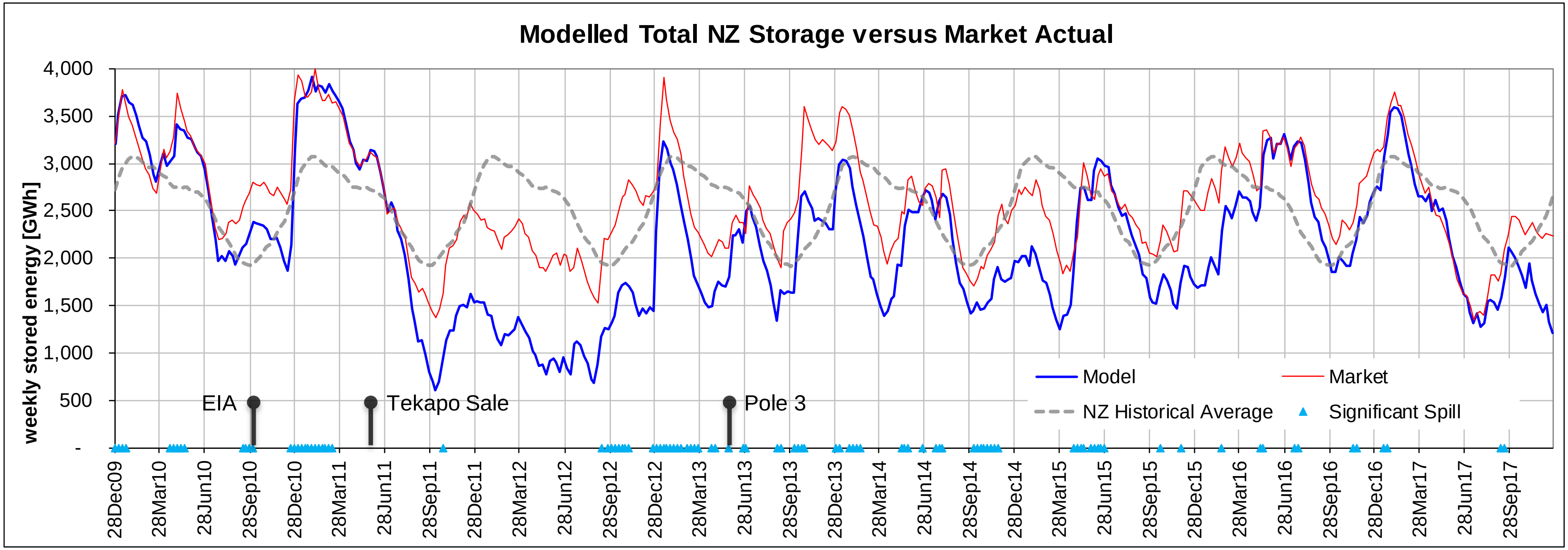
Hindcasting: Full Storage Distribution

- Beginning in Jan-2010 LPcon forecasts a wide range of storage outcomes over the following 8 year period corresponding to 86 different historical hydrological sequences:
  - We can view this via a tidy looking percentile distribution perspective, where we see a wide range of possible outcomes (in blue).
  - Note that the simulated reality is much noisier than this suggests with individual forecasts creating a chaotic “spaghetti chart” (eg pp16).
- Superimposed over the top is the market outcome (in red) as occurred in reality as well as the historical average from 1980 (in grey).
- Actual storage has oscillated within the bounds of the feasible LPcon forecast.
- We seldom see actual excursions into the low forecast range with 2017 being an obvious counter-example.



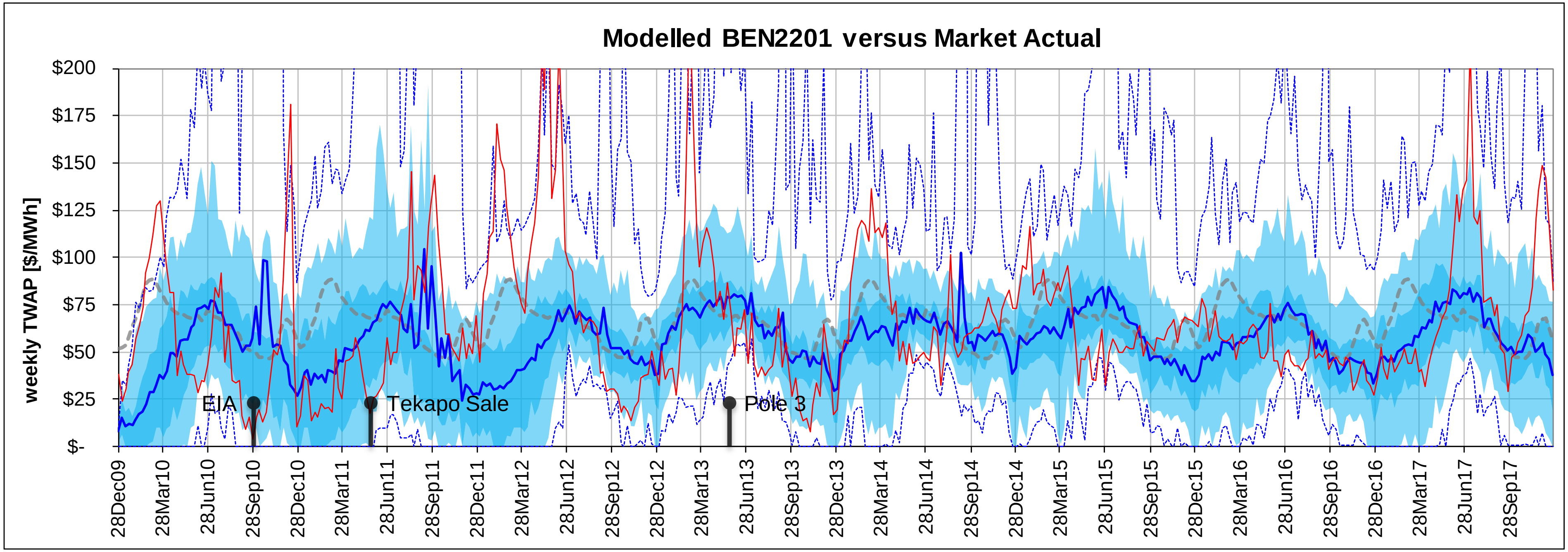
Hindcasting: Actual Storage Comparison

- We focus now on the <u>same inflows</u> as occurred in reality over the 2010-2017 period and compare actual storage management to that of the model:
  - Total NZ storage behaviour shows – in general – a good alignment with modelled results:
    - Reservoir levels fall when inflows experience a dry period and rise when inflows arrive.
  - At times the two levels match very well, and other times – especially when dry – they do not.
- There is a tendency for real world storage outcomes to sit higher than the model:
  - The reasons for this bias are unclear with risk-aversion and model methodology both possible.
- None-the-less, this suggests in the real world:
  - No security of supply issues when dry.
  - Increased likelihood of greater spill when wet.
- This different attitude to storage risk may be desirable for NZ, but it comes at a cost: spill.



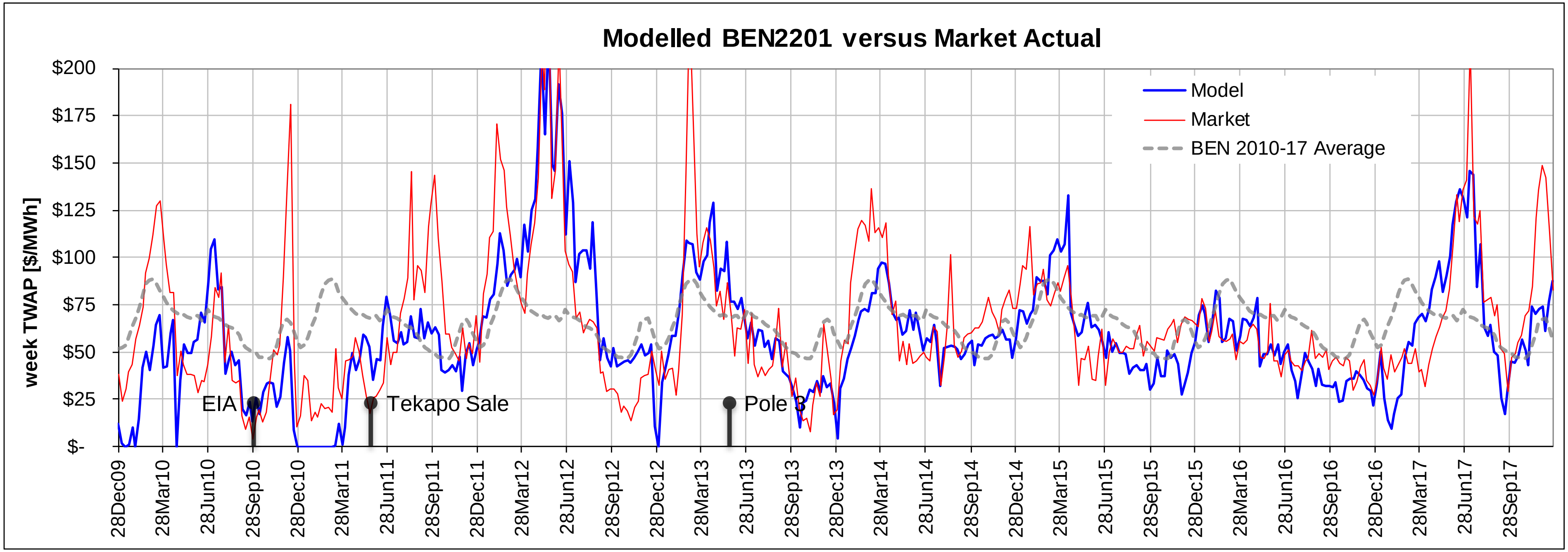
Hindcasting: Full Price Distribution

- Beginning in Jan-2010 LPcon forecasts a wide range of price outcomes over the following 8 year period corresponding to 86 different historical hydrological sequences:
  - We can view this via a tidy percentile distributional perspective, where we see a wide range of possible outcomes (in blue).
  - Marginal pricing is inherently a more chaotic metric than that of storage – true for both markets and for models.
- Superimposed over the top is the market outcome (in red) as occurred in reality as well as the 2010-2017 average (in grey):
  - Actual prices have mostly oscillated within the extreme bounds of the feasible LPcon forecast.
  - Excursions do occur both below (especially in the NI reflecting generators reluctant to get off the bus) and above (short-term supply concerns resulting in price spikes) the forecast range shown here.



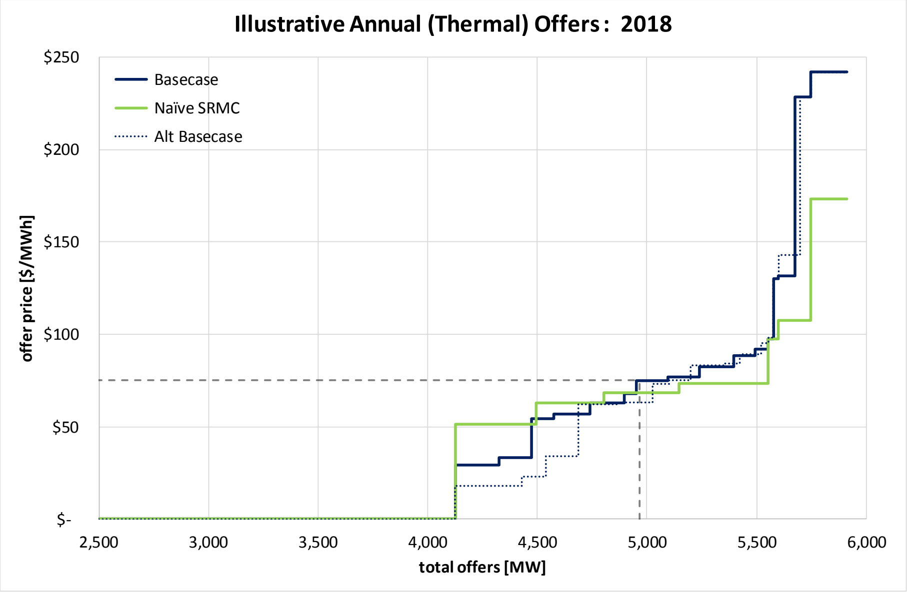
Hindcasting: Actual Price Comparison

- Examining market prices for the same hydrological sequence we see:
  - A good level of general alignment with aspects of seasonality and supply & demand pressures reflected in a similar fashion.
  - Hydro related scarcity signalling functions well.
  - Average prices in the market – for this set of inputs – sit higher than the model ($65 vs $60).
  - Market & modelled prices both show occasional spikes – although not always at the same time.
- A change in market price conditions and volatility is seen post Pole 3 (2012).
- In general model prices do not support a wealth transfer argument compared to market:
  - Keeping in mind that here we are ONLY examining hydrological uncertainty.
- But what if we assume different uncertainties and/or different thermal offer behaviour?



Hindcasting: Thermal Offers

- Thermal offer behaviour is a key determinant of price outcomes in hydro-thermal models:
  - We assume in our base-case a simple, annual cost-reflective approach with a 3 tier structure:
    - Tier 1 < SRMC, must-run and/or take-or-pay
    - Tier 2 = SRMC, reflection of fuel costs
    - Tier 3 > SRMC, + some O&M cost recovery
  - Fuel costs and O&M are anchored to that implied by annual financial disclosures.



- Power system modelling traditionally placed significant focus on SRMC:
  - Thermal SRMC = station heat-rate x fuel cost
  - Storage SRMC = water-value calculated using thermal SRMC assumptions, inflow uncertainty, and system shortage costs (VoLL).
  - Largely a naïve analytical convenience.
  - However there are not many thermal plant costs in NZ that are genuinely marginal:
    - Limited spot secondary thermal fuel markets.
  - Additional complications associated with thermal storage.
- Also issues in estimating parameters related to thermal running costs with great certainty:
  - Fuel costs are often lumpy in nature and sometimes not known with full certainty in advance.
  - Heat-rates can vary significantly.
  - O&M costs and plant characteristics can vary depending on how a plant is run.
- There are ALWAYS more costs than you think.

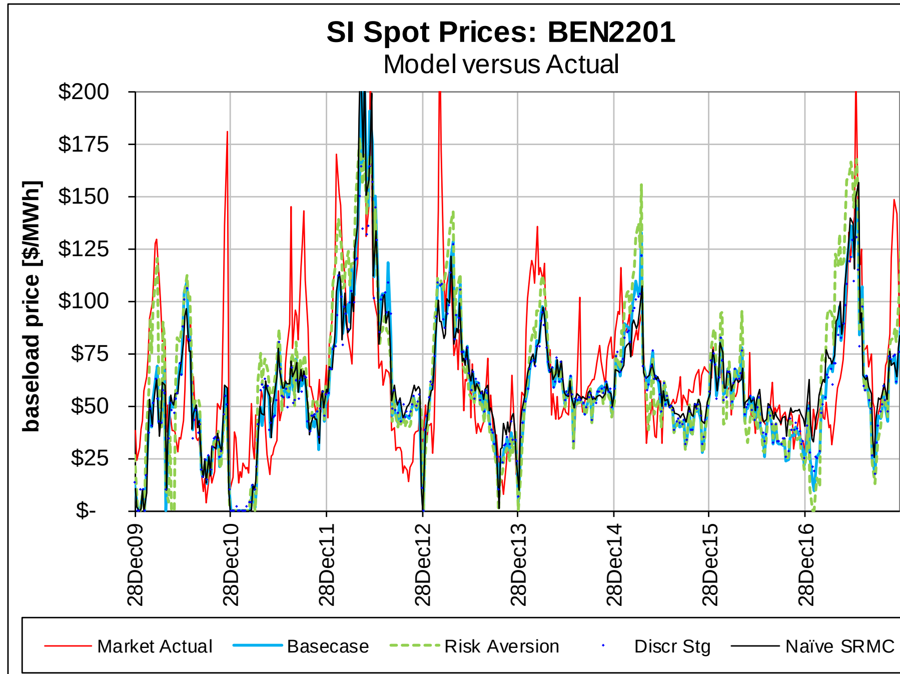
Caution should be applied in reading too much into conclusions drawn from a simple SRMC assumption.

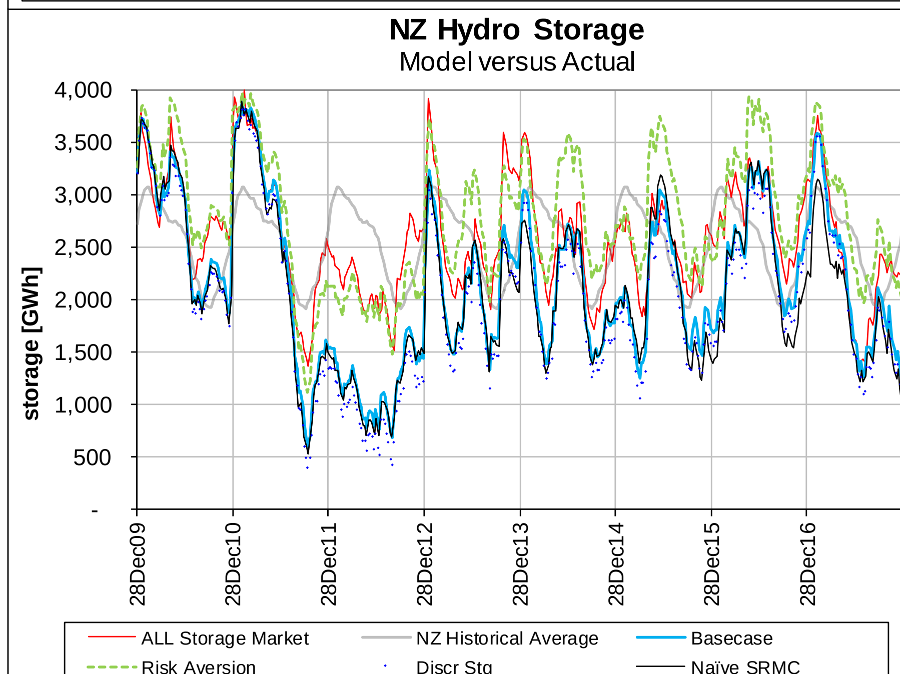
Hindcasting: Other Perspectives

- SRMC, efficiency, & risk are not precise concepts with valid variations to many components.
- We repeat the benchmark exercise & examine variations in outcomes arising from changing the attitude to water valuation through:
  - System risk-aversion.
  - Inclusion of discretionary storage.
  - A naïve approach to thermal SRMC.
- Price behaviour is robust to these assumptions:
  - Greater price pressures are seen overall with an SRMC approach and particularly due to risk-aversion with average prices close to market.
- Storage behaviour is largely unchanged by an SRMC perspective but shows a significant difference under a risk-averse assumption:
  - A good market match is seen pre 2013 (Pole3) and thereafter sits higher than market.

Market Baseload Price (TWAP)
2010-2017

	Market	Basecase	Risk Aversion	Discretion Storage	Naïve SRMC
BEN2201	$ 65	$ 59	$ 63	$ 58	$ 61
HLY2201	$ 70	$ 65	$ 67	$ 65	$ 67
change from market					
BEN2201	$ -	-$ 6	-$ 2	-$ 7	-$ 4
HLY2201	$ -	-$ 4	-$ 3	-$ 4	-$ 2





Final Thoughts and Observations 1

- Reservoir levels do not appear to be managed imprudently to low levels – contrary to some recent public commentary.
- If anything, reservoir levels *could* be argued to be held too high too often:
  - Which if true would have on-going cost implications for the NZ power system.
    - Addition hydro spill requires more thermal fuel burn than otherwise necessary.
    - Additional hydro spill will also bring forward in time generation investment decisions and significant associated capital costs.
- Risk-aversion appears a valid assumption in explaining at least some storage management since the introduction of the EIA (2010):
  - A change in risk management occurs around 2013.
- A risk-averse approach to storage management may be both desirable and prudent for NZ:
  - Certainly the market is calmer in dry events than it was prior to 2010.
  - However there is a need to avoid double-counting of risk.
  - Associated risk costs should be clearly understood and debated.
- Physical market outcomes over a prolonged period of time are largely explainable and – depending on your attitude to system risk – can be considered to align well with what a *risk-averse* central planner would prefer.

Final Thoughts and Observations 2

- Price signalling of scarcity or abundance in regards the hydro system appears to be functioning well:
  - Prices increase when hydro is scarce and storage levels fall.
  - Prices fall when hydro is plentiful and storage levels rise.
- Price outcomes can show divergence from time-to-time with underlying market costs driven by hydrological uncertainty:
  - In terms of the overall price level; and
  - During short-term price stress events.
- However this effect is not large when viewed over a longer time-frame:
  - Care must be taken in interpreting too much from a given year.
  - Model prices are 2.5 - 10% below market.
  - Uncertainties in forward views in addition to hydrology will close much of this gap.
- The pursuit of efficient wholesale market costs as defined by SRMC needs to be contrasted against the benefits of "workable competition" as we have observed it over the last 20 years:
  - Storage scarcity signalling occurs appropriately.
  - Market prices at $65-$70/MWh over the last 8 years are well below most estimates of historic new build costs.
  - Market investment/disinvestment dynamics are working well:
    - $9B (real) and 20TWh in generation investment since 1996.
    - $2.4B in new transmission lines.
    - 2.3GW old plant retired.
  - The capital investment risk sits with investors not taxpayers (mostly).
  - Retail competition is healthy, multiple new entrants, with innovation occurring.

Additional Material

LPcon: Overview

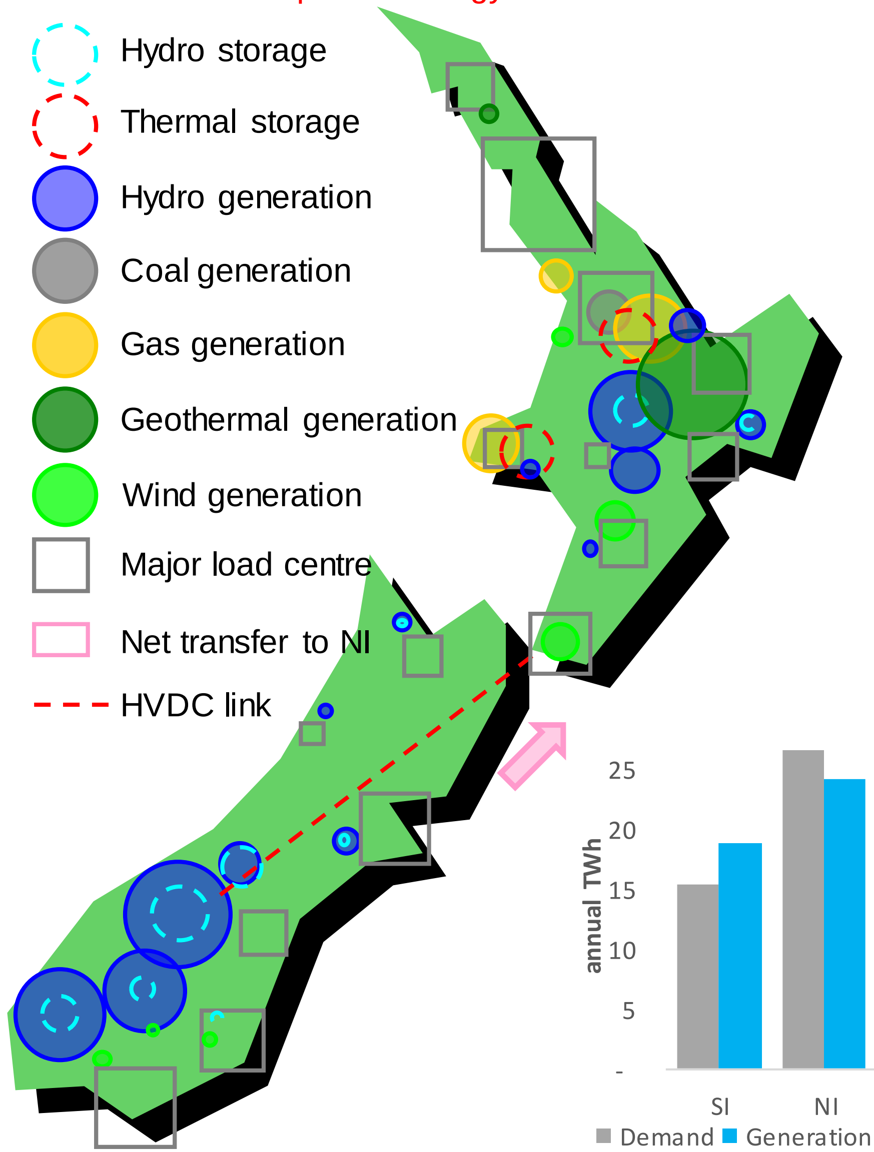
- LPcon is a traditional power system model:
  1. Stochastic reservoir optimisation:
     - Option valuation of water in storage.
     - Demand-curve addition with inflow convolution.
  2. Power system simulation.

- Features include:
  - Regional transmission, losses, constraints, sources of generation, and demand.
  - Weekly demand steps with 15 block LDC per week (variable duration)
  - Dynamic system instantaneous risks (AC, DC, CE, & ECE), reserves, and HVDC reserve sharing.
  - Regulation reserve for wind and solar.
  - Hydro flexibility, individual storage representation, and inflow uncertainty.
  - Within-week intermittency for wind, solar, etc.
  - Monte Carlo uncertainty for all system elements.

- The LPcon model seeks to balance the costs of excess spill and high market offer costs against the costs of excess system shortage:
  - In the face of uncertain hydro inflows it aims to minimise the overall NZ supply cost.

Major Generation Sources

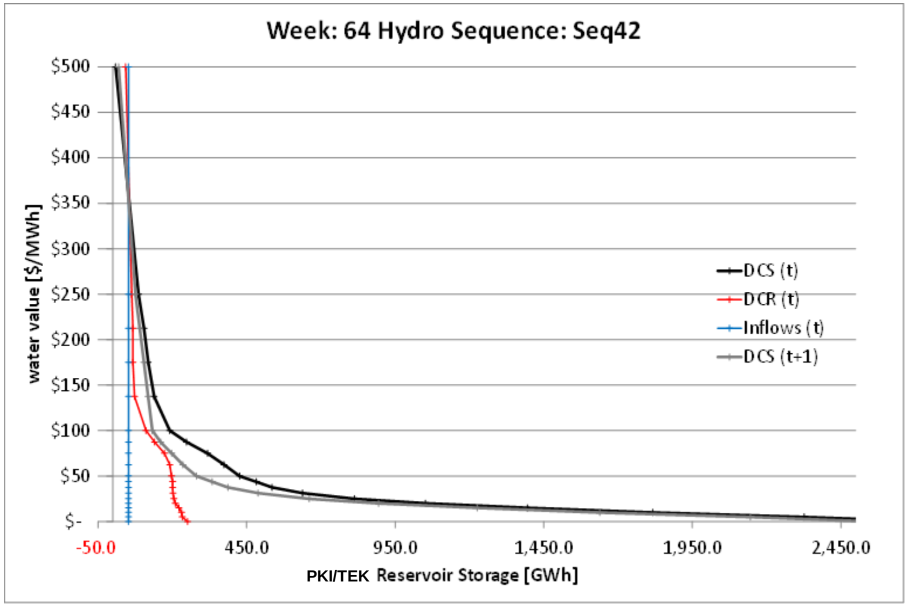
Scaled to size of expected energy contribution in 2018



LPcon: Water-valuation

LPcon is a two-stage hydro-thermal **optimisation** and simulation model of the NZ power system.

1. Optimisation stage:
   - WORK BACKWARDS to calculate water-values.
   - Stochastic, discrete, demand curve addition:
     - Start at a point in the future (T).
     - Take the demand curve for storage (DCS) at the end of the period t (week), user defined for t=T.
     - Calculate the demand curve for release (DCR) for the week on a discrete price grid (40-50 points).
     - Account for inflows that arrive into the reservoir during the period:
       - Inflow uncertainty (defined by inflow history, h) creates multiple versions of $DCS_{bop(t)}$.
     - Determine the DCS for the beginning of period:
       - Average across all DCS instances to create a single, convolved $DCS_{bop(t)}$ for the week.
       - This is used as the water-value surface for week t and as $DCS_{eop(t-1)}$.
     - Step backwards in time and repeat until t = 1.
   - Applied to a single reservoir at a time (a single storage state-space) with a simple Markov process to account for inflow serial-correlation:
     - Loop through each reservoir in turn with simplified & smoothed run-of-river assumptions made for non state-space reservoirs.



Recursive step:

$$DCS_{bop(h,t)} = DCS_{eop(t)} - Inflows_{(h,t)} + DCR_{(t)}$$

DCR calculation:

For reservoir r, for each WV = 1..N

$DCR_{(wv,t)}$ = reservoir dispatch quantity from market solve:

$$\text{Min}\{\text{sum}_{all\_gen}(\text{genQ x offerP}) + \text{genR x WV}\}$$

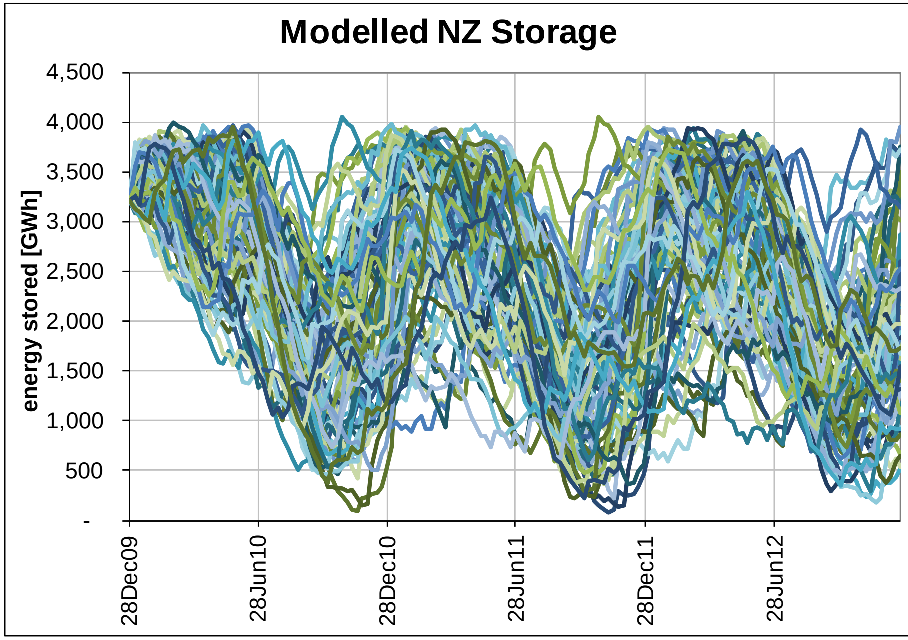
Subject to:

- sum(gen) = demand
- transmission constraints, Kirchhoff's laws, losses
- risk and reserve constraints
- hydro and thermal flexibility constraints
- wind and tributary flows availability
- … etc

LPcon: Simulation

LPcon is a two-stage hydro-thermal optimisation and **simulation** model of the NZ power system.

2. Simulation stage:
   - WORK FORWARD for operational system forecast.
   - Use water-values calculated in #1 above.
   - Simulate the market in the usual SPD-like fashion across all historical hydro sequences:
     - Security-constrained DC approximation of optimal power flow with dynamic hydro & thermal offers.
     - This can be as complex as you want to make it in terms of transmission resolution, time-step, river-chain details, demand resolution, thermal station constraints, system reserves, offer behaviour, etc
     - This creates multiple, separate simulations of the future as determined principally by hydrology.
     - Due to low serial correlation inherent in the NZ system, assumes that the best forecast of future hydrological outcomes is what has occurred in the past – in this case catchment inflows over the 1932-2017 period.
     - Huge volumes of simulated data are created – dispatched energy, power flows, risks, reserves, prices, revenues – and available to be examined and used for scenario-based forecasting and decision support analysis.



Market Solve:

For reservoir level s for reservoir r and week t look-up $WV_{(r,s,t)}$

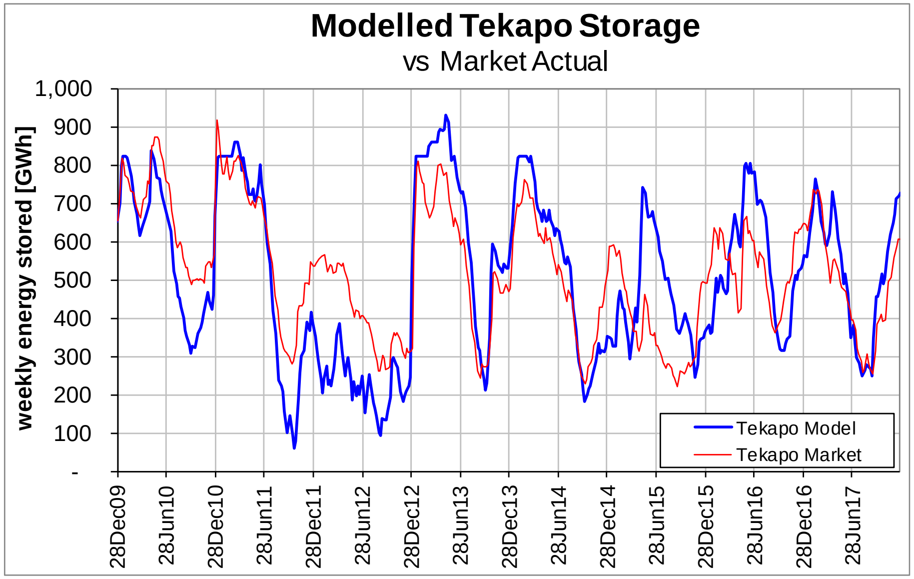
Solve market model:

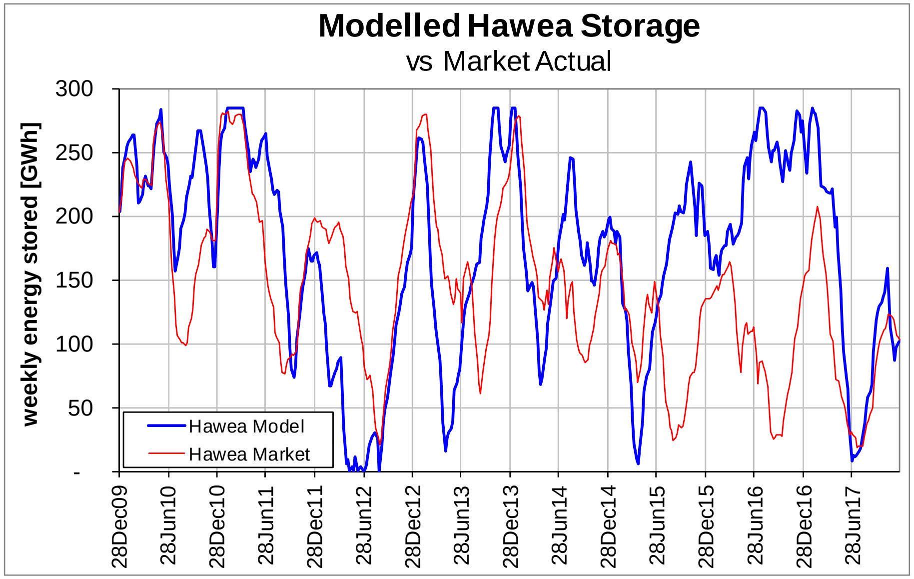
$$\text{Min}\{\text{sum}_{all\_gen}(\text{genQ} \times \text{offerP}) + \text{genR} \times WV_{(r,s,t)}\}$$

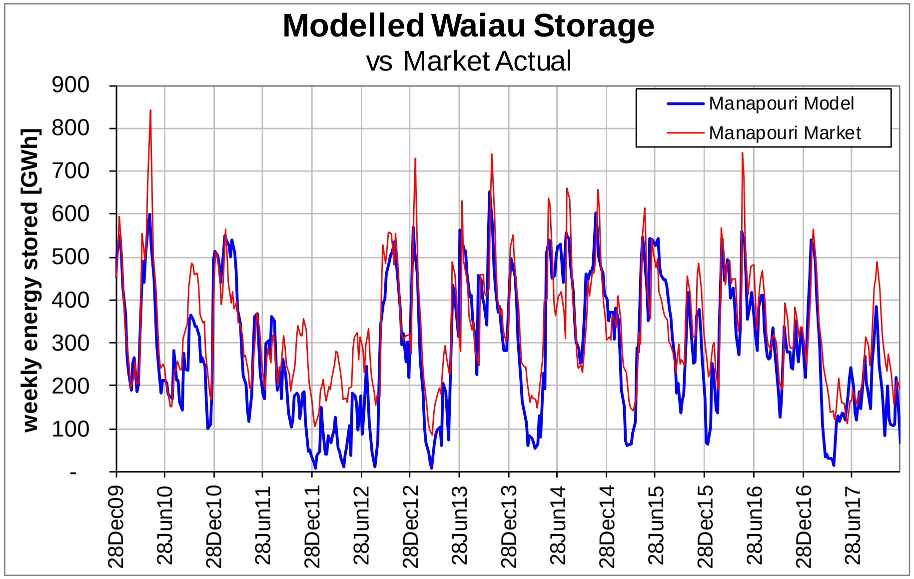
Subject to:

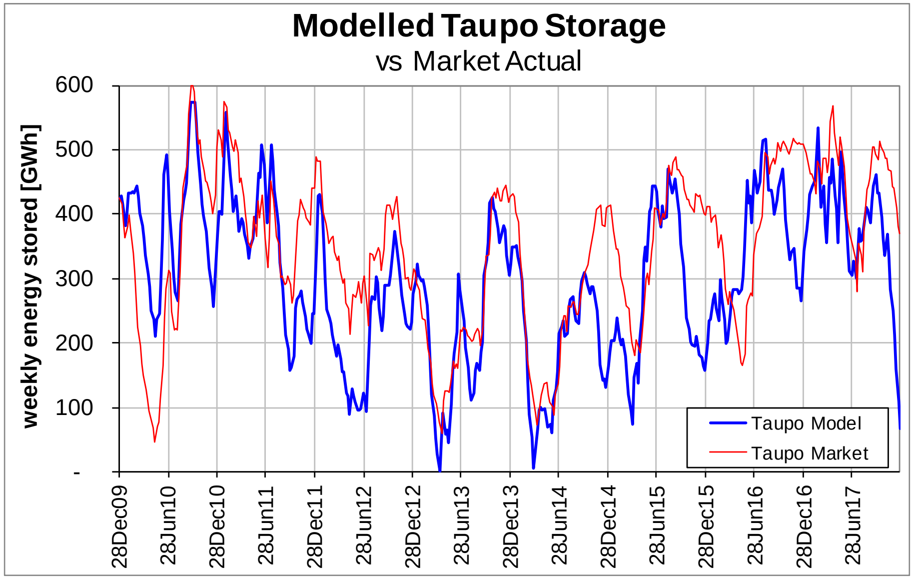
sum(gen) = demand
transmission constraints, Kirchhoff's laws, losses
risk and reserve constraints
hydro and thermal flexibility constraints
wind and tributary flows availability
… etc

Hindcasting: Additional Storage Comparison

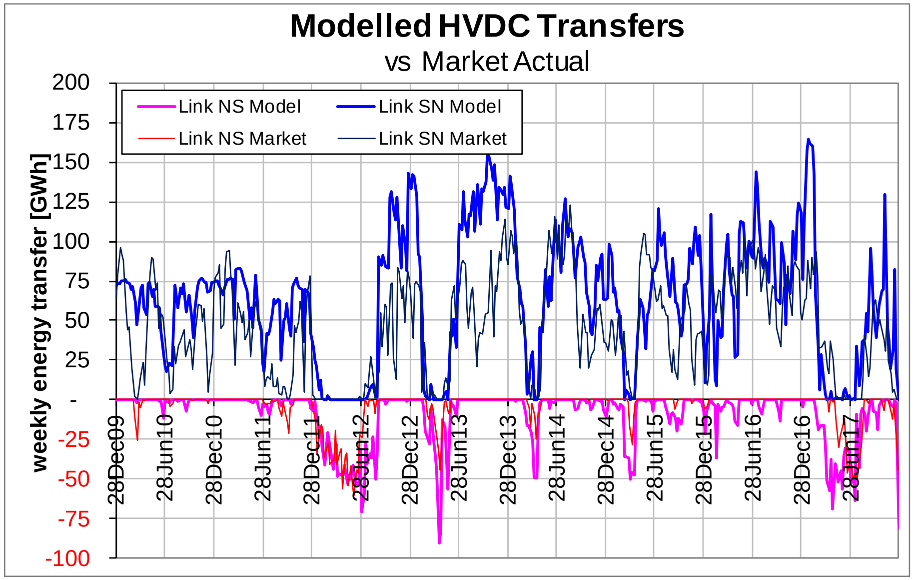


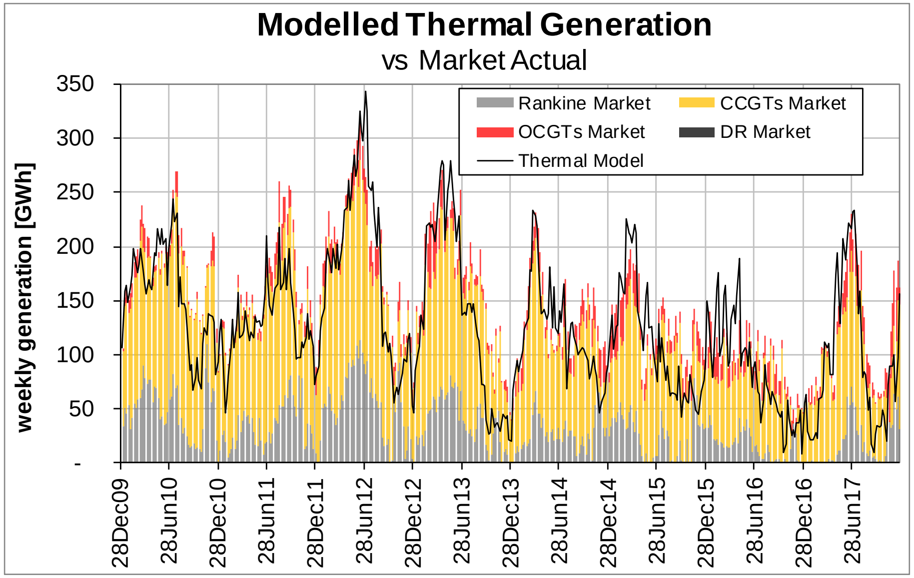


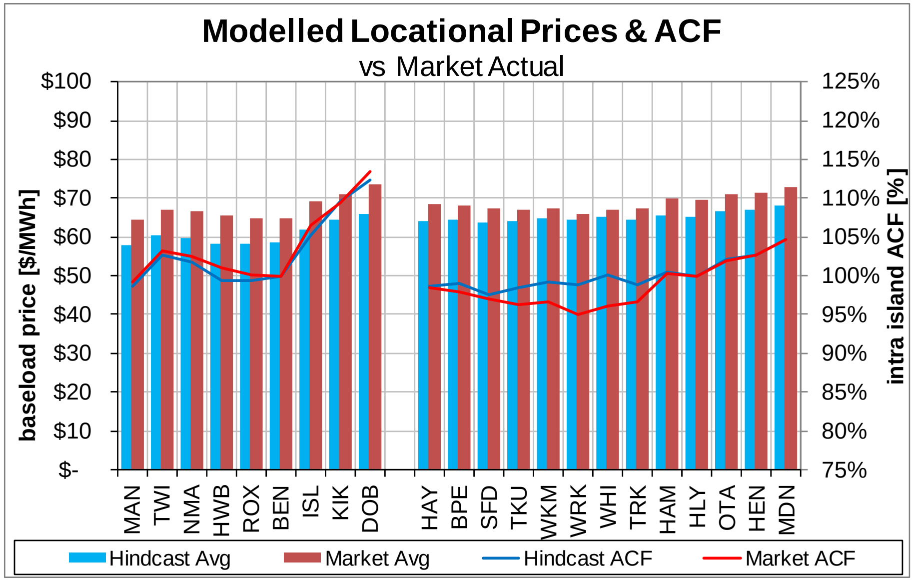


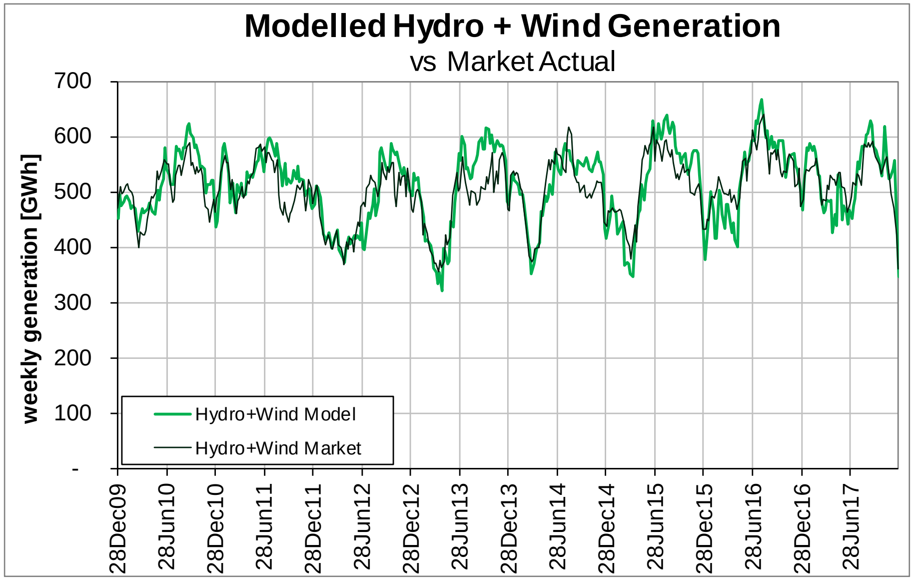


Hindcasting: Other Data Comparison









Hindcasting: Price Comparison by Year