# Market Power in the NZ wholesale market 2010-2016

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# Executive Summary

**Background.** Over a decade ago the NZ Commerce Commission engaged Frank Wolak to investigate market power in the New Zealand wholesale electricity market. Professor Wolak (2009) found evidence of substantial market power with market power rents of $4.3 billion over the seven-year period (2001-2007) covered by the report. There were a number of criticisms of the report, the most substantial of which was the assumptions made around the value of water, which was capped at the marginal cost of thermal plants. Browne et al (2012) using a different methodology argued that water values during dry years would at times be higher than this. Using a computer agent based approach to model market power and a calibrated water value curve they found similar market power rents to those calculated by Wolak. Philpott and Guan (2013) using stochastic dynamic programing to calculate water values also found high market rents.

**Changes in market conditions mean that it is timely to investigate market power**. Since the Wolak report, Browne et. al. (2012) and Philpott and Guan (2013) there has been no quantitative investigation into market power in the NZ wholesale market, even though there have been considerable changes in market conditions. Despite little demand growth over the last decade there has been a significant increase in new wind and geothermal generation. More recently, a number of thermal plants have exited the market and there have also been line upgrades. Furthermore there has been a number of market design changes aimed at alleviating market power and managing risk better in years of low inflows into the hydro dams. Thus it is timely to investigate whether there are still market power issues in the wholesale market.

**Competitive Benchmark.** The approach used in this report to model market power is to construct the competitive benchmark, where all plants bid into the market at their marginal cost. There is one exception - hydro bids into the market using the water value. The water value curve is computed as a function of the actual lake level, compared to the mean, for any given day. We compare the competitive benchmark to the prices simulated by the computer agent-based firms trying to maximise profits and attribute the difference as market power rents. We also compare the competitive benchmark to actual prices and compute rents using this approach. It turns out both approaches give similar results.

**A new dynamically consistent model.** We start off using the approach advocated by Browne et. al (2012), to investigate market rents over a seven year period from 2010-2016. This approach gives substantial market rents. However we argue that there is a dynamic inconsistency in this approach, as the competitive benchmark consistently dispatches more water than the strategic simulations, which cannot continue for any length of time as the lakes would eventually become empty. We constructed a model that is dynamically consistent by keeping track of dispatch and inflows for each time period and updating the lake level to find new water-values in the following period. This is our preferred approach as it is dynamically consistent and has simulated prices close to actual.

**Lake level paths and prices over the course of the year are similar to actual paths. The competitive benchmark lake level at the end of the year is very similar to the simulated lake level when firms behave strategically.** Figure (i) below is typical, based on 2011 output. The simulated lake level path in green broadly follows the actual path in blue in the top panel. The competitive benchmark path is typically different, as expected, however at the end of the year the lake levels of the competitive benchmark and the market power simulations are very close. Simulated prices tend to broadly follow actual prices. Although the simulated model price and lake level paths do not follow exactly the actual path, the agreement is very good considering that the real world is considerably more complex than this model.

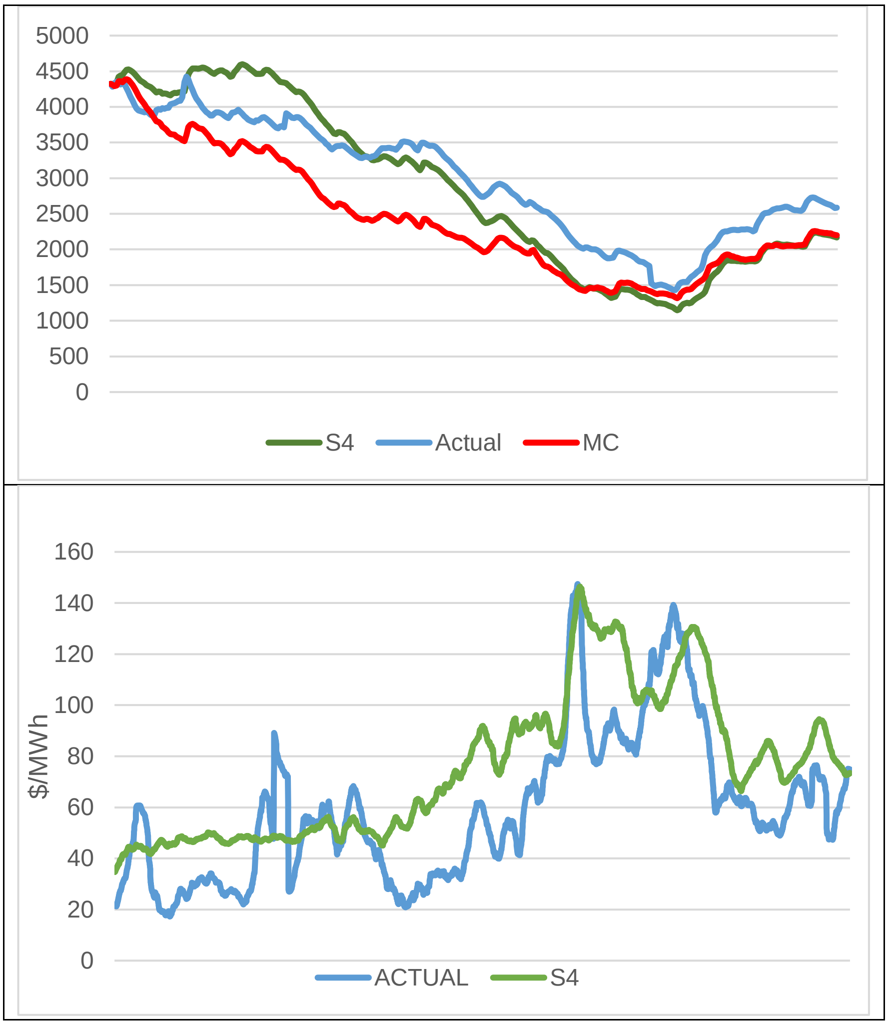



*Figure i: 2011 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

**Simulated prices are very close to the average of actual prices 2010-2016. However, most years there is some difference – typically \$5-\$10/MWh over the year.** Table ES 1 summarises simulated prices for each year using the methodology of Browne et. al (2012) (which we label CP) and the prices generated using the new dynamic methodology. These are compared to actual prices for each year. Over the ten years, average, yearly, simulated prices, using the approach taken by Browne et al (2012), were \$6/MWh below the actual prices. The yearly average dynamic prices are even closer – just \$5/MWh below the actual. The agreement gives us confidence in our methodology for estimating market power.

*Table i: Annual average prices.*

| Year | Actual | CP | Dynamic |
|---|---|---|---|
| 2010 | 60.1 | 56 | 65.5 |
| 2011 | 63.1 | 58.1 | 67.8 |
| 2012 | 84.8 | 84.3 | 84.3 |
| 2013 | 65.9 | 59.1 | 52.3 |
| 2014 | 76.7 | 60.3 | 63.7 |
| 2015 | 69.1 | 70.3 | 57.0 |
| 2016 | 56.6 | 47.8 | 49.9 |
| **Average** | **68** | **62.3** | **62.9** |

**Market power rents are substantial.** The computed markets power rents over the period 2010-2016 are substantial. They are similar or even higher, as a fraction of revenue, to those found by Wolak (2009). Table (ii) below shows computed market power rents for each year using our dynamic competitive benchmark and market power simulations. Over the 7-year period of the study total simulated market revenue was $14.9 billion. Total market rents are $5.4 billion, which is 36% of revenue. Table (iii) presents market power rent calculations using actual nodal prices for each year rather than simulated prices. Over the 7-year period total market rents are 6.0 billion, or 39% of revenue – about 10% higher than the results using simulated prices, reflecting slightly higher actual prices. The distribution of rents is also different, with lower rents in the earlier years and higher rents in the later years compared to the simulated results. The likely reasons for this are discussed further in the paper.

*Table ii: Simulated market power rents.*

| Year | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total revenue | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|
| 2010 | 1861 | 588 | 24% | 2449 |
| 2011 | 1668 | 678 | 29% | 2346 |
| 2012 | 1569 | 1305 | 45% | 2874 |
| 2013 | 1146 | 554 | 33% | 1700 |
| 2014 | 1290 | 831 | 39% | 2121 |
| 2015 | 1142 | 759 | 40% | 1901 |
| 2016 | 856 | 688 | 45% | 1544 |
| **SUM** | **9532** | **5403** | **36%** | **14935** |

*Table iii: Estimated market power rents using actual prices.*

| Year | Simulated Competitive Benchmark Revenue ($million) | Estimated Market rents ($ million) | % of total revenue | Actual Wholesale Revenue ($million) |
|---|---|---|---|---|
| 2010 | 1861 | 333 | 15% | 2194 |
| 2011 | 1668 | 393 | 19% | 2061 |
| 2012 | 1569 | 1077 | 41% | 2646 |
| 2013 | 1146 | 1003 | 47% | 2145 |
| 2014 | 1290 | 1136 | 47% | 2426 |
| 2015 | 1142 | 1044 | 48% | 2186 |
| 2016 | 856 | 1058 | 56% | 1878 |
| **SUM** | **9532** | **6044** | **39%** | **15536** |

**Changing in market conditions.** There is some evidence that market power rents have increased over the last few years. From 2010-2012 market rents under the simulated comparison are 33% of revenue, whilst from 2013-2016 rents are 39% of revenue. (The difference is even more pronounced in the comparison to actual prices, which shows average rents of 25% from 2010-2012 and 50% of revenue from 2013-2016). Despite falling prices due to an increase in low marginal cost supply our model suggests that firms are able to exploit market power, with costs coming down faster than simulated prices. However the different hydrological conditions and small sample size mean that this conclusion is tentative.

# 1 Introduction

The New Zealand electricity market design, which is "Energy Only", is one of the least regulated markets in the world. There are very few explicit measures aimed at alleviating market power – for example there is no price cap or capacity market. Exercise of market power is allowed and is widely seen as a way for generators to recover their fixed costs (Philpott, Read, Batstone and Millar, 2018). The New Zealand Electricity Authority, which is the regulatory agency, aims to encourage competition by reducing barriers for entry rather than explicit market oversight. In contrast, all North American markets have regulations to directly mitigate market power including price caps as well as real-time market power mitigation. An example is the PJM market which uses the three-pivot test. If the combined offers of the three largest suppliers are pivotal their offers are reduced by the market oversight authority to cost based bids (Crampton, 2017).

Given the light-handed regulatory approach, the New Zealand market is ideal to investigate market-power issues. Over a decade ago the New Zealand Commerce Commission was concerned enough about market power that it asked Frank Wolak (2009) to write a report to quantify market power rents. The Wolak report, as it became known, examined the period 2001-2007. Another study (Browne, Poletti and Young, 2012) using a different methodology computed market rents for 2006 and 2008. Both studies found that market power rents were considerable – over 25% of total revenue for some years. As will be seen below both of these studies have been criticised by academics as well as policy makers with the New Zealand Treasury (2012) dismissing the $4.3 billion market rents calculated by Wolak as "not credible". Additionally the New Zealand Treasury does not discuss the very careful and thorough work of Philpott and Guan (2013)[2], perhaps because the focus of the paper was on productive inefficiencies, however they do compute market power rents 2005 - 2008. They use a stochastic programme to estimate counterfactual competitive benchmark water values and report market rents as well as productive inefficiency of actual dispatch compared to the competitive counterfactual. For the year 2005 they calculate market power rents to be $935.4 million, very similar to those calculated by Wolak, of $950.7 million.

The extent of market power in the New Zealand wholesale market is clearly a controversial topic. Over a decade later it is timely to re-examine this issue. We use a new methodology here to calculate market power rents over the period 2010 - 2016 and find that market power rents continue to be high.

There is an extensive literature on modelling market power in electricity markets. Different approaches include using supply functions (Green and Newberry, 1992); identifying whether firms are net pivotal (eg Newberry, 2009 and Sweeting, 2007); using computer-agent based models (Bunn and Oliveira, 2003); and using Cournot models (eg Borenstein, Bushnell, and Wolak, 2002). Most studies find that there is market power in the electricity wholesale market, which at times can be dramatic. For example Bornstein et al. (2002) find that market power mark-ups over the competitive price, for California in 2000 were approximately 100%. Most studies start from the assumption that

[2] The latest version was released in 2013, however versions were available several years earlier.

market power arises legitimately with firms acting independently, however at least one study finds evidence of tacit collusion (Sweeting, 2007).

The approach taken here is similar to the competitive benchmark analysis (Mansur, 2008) used by many authors. Counterfactual competitive offers into the spot market are constructed using estimated marginal costs with information about transmission line capacities, generator outages, and market demand used to construct perfectly competitive prices which are compared to actual or simulated wholesale prices. If firms behave competitively they will submit bids into the market at marginal cost with the market price usually set by the highest cost unit dispatched (Stoft, 2002). The difference between this benchmark and actual or simulated prices would then be a measure of market power rents.

For thermal systems this is a relatively simple exercise, however it is not straightforward for systems with large amounts of hydro generation if there are storage constraints on the lakes. Marginal costs for thermal generators are generally well known. However, the marginal costs for hydro generators (those with storage) can vary wildly depending on the opportunity cost of water. If the storage lake is full, and more water is flowing in, there is no value in storing any water for the future, i.e. the opportunity cost of using water is zero. On the other hand, if there are low inflows to the lakes, and a spike in demand is forecast, the opportunity cost of using that water now is the price the hydro generator could have received had it held the water until the demand spike.

One of the few papers to analyse such a system is Bushnell (2007) who constructed a Cournot model of competition between firms that each possess a mixture of hydroelectric and thermal generation resources. He uses data from the western United States electricity market with a constraint on total dispatch over the time period modelled. He found that firms reduce peak supply and increase off-peak supply compared to the competitive benchmark which allows them to push average prices up considerably. Another study that investigates market power in a hydro dominated market is Tangerås and Mauritzen (2014) who find prices in the Nord-pool market are above marginal costs (including the opportunity cost of hydro). This is despite the storage lakes in the Nord-pool market being very large compared to the scale of energy demand.

In the New Zealand context the most significant study on market power in the New Zealand Electricity Market (NZEM) is the report by Wolak (2009), discussed above. Wolak concluded that over the seven-year period he studied, market power rents amounted to $4.3 billion dollars. This figure attracted considerable media attention and the report's methodology came under considerable criticism. The Electricity Technical Advisory Group (ETAG) released a report a few months after Wolak (ETAG, 2009) summarising "serious reservations" by commentators regarding the calculation of the rents reported by Wolak. In contrast to Wolak's report, ETAG concluded that "there is no evidence of sustained or long term exercise of market power" (p40).

Branson (2009) reviews the criticisms raised by ETAG (2009) of Wolak's analysis and dismisses many of these out of hand. However she strongly agrees that the Wolak report underestimates the opportunity cost of stored water, thus overestimating the extent of market power. The University of Auckland Energy Centre and University of Auckland Electric Power Optimization Centre (Energy Centre and EPOC, 2009) and Evans et al. (2012) also made this point. Other criticisms include: arguments that Wolak failed to properly take transmission constraints and plant availability into account and ignored possible demand responses (Evans et al., 2012); an argument that Wolak overstates the incentives of vertically integrated firms to exercise market power in the New Zealand electricity market (Hogan and Jackson, 2012); as well as direct criticism of Wolak's empirical methodology (Evans and Guthrie, 2012).

As seen above, much of the criticism of the Wolak report was directed at the way Professor Wolak treated the issue of water values for the hydro generators. During dry year events, Wolak determined that water values should be set equal to the most costly thermal unit since, he argued, there was always spare thermal generation. In our view, and in the view of many others, this does not properly take into account the potential risks and uncertainties surrounding a dry year event. It may well be the case that with hindsight one can infer that hydro generators managed their water too conservatively. However at the time hydro operators have to consider a range of different scenarios, some of which may lead to very high prices or even forced outages which could push the price up to VOLL (which is usually set at around $10,000MWh in New Zealand). Thus there will be times when the opportunity cost of hydro generation has a value above the marginal cost of generation. Since the water values that the generation firms use to determine their offer stack into the wholesale market are private knowledge, they must be inferred indirectly. Following an approach similar to that advocated by Tipping et. al. (2004) and Young et al (2012) we model water values as a function of national lake storage levels. In reality water values reflect price expectations and will be a complicated function of a number of factors including lake levels, expected inflows, expected demand and expected changes in non-hydro plant availability. However, as Tipping et. al. and Young et. al. show, modelling water values as a simple function of expected lake levels does a surprisingly good job. We use this approach to compute competitive benchmark prices for our target years.

As discussed above, the two quantitative investigations into market power rents in the NZEM were over a decade ago. Since then there has been considerable changes in the NZEM with demand much flatter than forecast and significant new wind and geothermal generation entering the market as well as the retirement of some thermal plants and significant line upgrades. Furthermore there has been a significant increase in hedge trades and a number of market design changes aimed at alleviating market power and managing risk better in years of low inflows into the hydro dams. The changes in the market mean that it is timely to investigate to what extent market power is still an issue in the market.

Although there has been no quantitative market power over the last decade the Electricity Authority (2012, 2013) has investigated the incentives and the ability that generators in the spot market have to raise prices using two different methodologies. They find that generators are structuring their offers to maximise profits. Whilst they may have, at times, the ability to raise prices they tend not to do so as the associated drop in their output reduces over-all profits. The work by the Electricity Authority however does not calculate what these market rents are.

New Zealand Treasury (2012) clearly is of the view that market power is not an issue, reporting to cabinet that "two independent peer reviews of Professor Wolak's report identified significant flaws with his methodology that render the conclusions he reached worthless" as well as

> Setting aside any flaws in Professor Wolak's methodology, the $4.3 billion figure for "excess profits" is not credible, as it represents over 90% of the total after-tax profits earned by the five major electricity companies. If these profits had not been made, these companies would have earned relatively small amounts on their billions of dollars of assets – certainly far less than their cost of capital - and would have had insufficient cash flows to fund any of the

> significant investment in new generation that occurred over 2001 to 2007 and the years following that. Without that investment, New Zealand would most likely be experiencing significant shortages of electricity and (ironically) higher prices. [p 4]

This is essentially the Long Run Marginal Cost (LRMC) argument made by the ministerial advisory group (Electricity Technical Advisory Group, 2009) who wrote “Using the LRMC benchmark, there is no clear evidence of the sustained or long term exercise of market power [in the NZEM] [p. 39]”.

These arguments should be taken with a grain of salt. Our view, and that of most economists, is that market power is being exercised whenever prices are consistently above marginal cost, which may well be below the LRMC for many years - since the investment costs are sunk.

In contrast to the position taken by government agencies, Geoff Bertram (2013) expresses the view that market power is found in the retail as well as wholesale market. He writes “that generator-retailers…are price gouging to increase their profits – a straight wealth transfer from consumers, reflecting the exercise of market power.” Clearly there is considerable disagreement on the extent of market power in the NZEM, a further reason for this report, which uses a new methodology to investigate these issues (explained below).

This work uses three different, but related methodologies to estimate market power rents in the NZEM 2010 - 2016. The first analysis uses the same methodology as Browne et. al. (2012). A computer-agent based market power simulation is compared to the competitive benchmark, where firms are forced to bid in at marginal costs – including the imputed water value for hydro. In this model, computer agents represent different firms in the NZEM, and search for profit maximising offers in the spot market by trial and error with an algorithm that reinforces profitable actions. This approach works well to simulate a single period price with given lake levels and demand. However, it does have a shortcoming, which is that the benchmark model tends to dispatch more low-cost hydro than the simulations which include market power. Over the course of a year this leads to dynamic inconsistency as eventually cumulative competitive dispatch leads to much lower lake levels than observed.

Thus we introduce a different dynamic methodology, where we keep track of dispatch and use hydro inflow data to model the change in lake levels and hence water values over the course of the year for the competitive benchmark as well as the simulations with market power. The lake levels over the course of the year are dynamically consistent using this approach. If the lake levels start to get low in the competitive benchmark the higher water levels lead to less dispatch which acts to correct the tendency for the competitive simulations to dispatch “too much” hydro. As will be seen below, the computer-agent based model has initial conditions which determine the starting bids into the spot market of the computer agent based firms. When prices are simulated for a single period there are only small differences in the final predicted prices depending on the initial conditions, which are generated by a random number seed. However using the dynamic framework, over the course of a year 4380 prices are simulated with lake levels changing and water values updated each period. This leads to considerably more variation in predicted yearly average prices. None-the-less in each case we could find a simulation with initial conditions that gave predicted prices very similar to actual prices. This approach, which we dub the “best seed,” is the methodology we favour, but we present results for all three approaches.

In Section 2 we describe the model. In Section 3 we present the main results. Finally in Section 4 we draw some conclusions.

# 2 Methodology

The computer agent-based model we use to model electricity prices in the NZEM, is described in detail by Young et al. (2011) and Browne et al. (2012)[3]. Here we summarise the key details. The computer agents are firms who own generation assets. Each period the firms offer all their available capacity into the spot market. The firms will typically choose to offer in different generation units at different prices. Some of the larger generation units are allowed to offer in up to four tranches of prices/quantity bids into the market by splitting them into units with smaller capacity. The offer prices are found by trial and error through a learning reinforcement algorithm. Each period, the firm draws offer prices for each of its generation units from a probability distribution which is updated at the end of the period using reinforcement payoffs. The market is cleared and profits computed. Actions that return high profits have an increased probability of being played the next round, with the process repeated 1200 times to simulate prices for a single half hour trading period. By the end of the simulation the computer has "learnt" what price offers will probably yield the best profits given the other firms' likely actions and the simulation ends. The average of the last 100 rounds of prices is computed to establish the simulated price prediction. Initial actions of each firm depend on the initial conditions that depend on a random number which we call a seed. For single period price simulation the final prices vary by a small amount depending on the seed (a couple of $/MWh at the most). We take an average over 5 seeds which we quote as the simulated price.

The model employs computer agents using the modified Roth and Erev algorithm with further modifications as suggested by Weidlich (2008). The market is simulated using a 19 node simplified version of New Zealand's network with electricity flows modelled by a DC flow model with line losses. Demand is assumed inelastic. The solver is a simpler version of New Zealand's market solver, and for given bids, demand, and network parameters, will output dispatch for each generator, prices at each node, and the flow on each transmission line.

Due to time constraints we have not constructed a network for each time period which would include data on period by period plant availability and any line outages. However there is generally a systematic difference between thermal plant availability in summer compared to winter. We roughly account for this by constructing a summer network and a winter network using the Electricity Authorities dispatch files. For some years we needed more than these two networks – for example if a new plant was commissioned part way through the year.

For example in 2010 summer the maximum generation from Huntly coal was 450MW with the Combined Cycle Gas Turbine (CCGT) plant at Otahuhu and the plant at Southdown not generating. Thus the summer network has Southdown and Otahuhu at 0MW and Huntly coal at 450MW. In winter all plants are operating except for Southdown with Huntly at a maximum generation specified of 800MW.

Some plants such as geothermal, wind, run of river hydro, or hydro on rivers with minimum flow requirements, are classed as "must-run". These are always dispatched in the model with bids of

[3] We dub the computer-agent based model "SWEM".

$0/MWh. We also accounted for plants set aside as spinning reserves, which cannot be dispatched on the spot market, by reducing the capacity of each plant by the average fraction of cleared reserves. We estimated these from Electricity Authority data to be 12% of total capacity.

The only contract explicitly included in the model was that held between Meridian and the Tiwai Point Aluminium Smelter. If this were not included transmission constraints in the South Island would leave Meridian as an effective monopolist. To account for this, demand is reduced at Tiwai by 570MW and the capacity of the Clyde dam is reduced by the same amount. The exception is 2009 when the smelter had reduced output for much of the year.

The firms in the agent-based model are assumed to have at least some incentive to maximise wholesale profits. All the major firms are vertically integrated. As noted by Wolak (2009) and Hogan and Jackson (2011), vertical integration means that firms have less incentive in the short run to drive wholesale prices up. However as long as they have some incentive to push prices up in the spot market the agent-based model should, in principle, be able to simulate prices effectively. The major firms are almost always net sellers onto the spot market. They either sell to large industrial users on real-time contracts or to other smaller firms that are net buyers on the spot market.

The calibration of the behavioural parameters for the agent based model[4] should implicitly account for the actual incentives that firms face to maximise spot market revenue. Similarly although we do not include long-term contracts between generation firms and load, which again may reduce incentives to maximise spot market revenue, they do not eliminate this incentive and, as above, the choice of behavioural parameters accounts for this.

Young et al. (2011) report how the behavioural parameters that describe the computer agents are calibrated using data from the centralised data set (CDS) of the NZEM. Initially, simulated prices are compared to actual prices for different behavioural parameters in an environment where water values are close to zero. Once the behavioural parameters are established water values are determined as a function of the difference between actual and expected lake storage level. They assume that the behavioural parameters established for periods where water is plentiful also describe the market when water is valuable. The water value is treated as an unknown effective marginal cost for the hydro generation assets. The water cost function is then backed out from observed market prices. They compare simulated and actual prices for different lake levels to estimate the unknown water value curve as a function of relative storage levels.

Clearly this approach depends crucially on the credibility of the agent-based model used here. Agent-based models are a relatively new approach to modelling electricity markets. Nonetheless, they are increasingly seen as a useful way of modelling realistic markets (Weidlich, 2008). The model used here is one of the most complex and realistic agent-based models for electricity markets existing. Young et al. (2011) establish that it simulates prices realistically on all 19 nodes of the simplified New Zealand electricity network across a range of market conditions for the validation year 2006. The calibration and validation results reported in Young et. al. (2011) gives us confidence that the model will accurately simulate prices, and that the conclusions we reach here will be credible and robust. There is one proviso however – the model was calibrated to 2007 data. As noted above, since then there have been changes in market conditions and institutional structure. Some of these, such as new geothermal supply and increasing demand should be accommodated within the current

[4] See Young et. al (2011) for more details.

model structure. Other changes, such as the increasing amount of hedge contracts, may impact on the accuracy of the simulations. However as seen below the model does surprising well at predicting prices. Not quite as accurate as reported in Young et al. (2011) but some of that will be due to the fact that we haven't constructed separate networks for each period, taking into account outages, or disruptions in gas supply. However, comparing the simulated prices to the competitive benchmark means that events like these are to some extent netted out.

Data on New Zealand generators was taken from the New Zealand Market Authority's Generation Expansion Model (GEM). The detailed cost functions we use can be found in Young et al. (2011). For thermal generators the marginal cost was computed from representative gas or coal prices using MIBE data for each year (Appendix B). Renewable fuel costs are zero but, like thermals, a small operating and maintenance cost is included in the marginal costs per MW. The hydro marginal costs include the water value as discussed above. The competitive benchmark model is used to establish competitive counterfactual prices assuming the same water value for the hydro assets established from the water value curve, with one difference, which is that the minimum water value is set to zero. We found that negative water values were not uncommon with market power simulation[5]. During dry year events we find water values rise considerably higher than Wolak assumed. Demand, generation data and actual market prices are from the Electricity Authority.[6] Lake level data and inflows (in GWh) were kindly provided by NZX Energy. Wind generation is from MERRA re-analysis data provided by Poletti and Steffel (2018). The data is in a more convenient form than that found in the Electricity Authority generation data and is strongly correlated with actual output.

The competitive benchmark for each year is constructed by forcing the agents to bid their capacity at marginal cost, including the calculated water value. Any differences in revenue between the agent-based model and the competitive benchmark we attribute to market power rents.

As discussed above, as well as using the computer-agent based model in a static setting, where each period prices are simulated independently of other period prices, we also use the model in a more dynamic setting, where the lake levels are updated each time period using modelled dispatch and actual inflow data. This means that the different period simulations are no longer independent since dispatch one period determines the lake level and hence water value the next period. We can then compare lake levels from the agent based simulations with, actual lakes levels, as well as the competitive benchmark to check for dynamic consistency over the course of a year. Not surprisingly we find path dependence in these simulations and variation in simulated prices, depending on the initial conditions (set by a random number or seed) for the agent based simulations. Systematic small differences in dispatch each period lead to different lake level dynamics over the course of a year. Both methods have pros and cons associated with them, which is why we present results from both approaches.

We also compare the competitive benchmark price to actual prices. If the simulated prices were the same as actual prices this would of course be equivalent. However overall simulated prices are about seven per-cent lower than actual prices, even more so for later years. This may be due to: (a) the model underestimating market power or; (b) it may be due to errors in the calibration process –

[5] Bushnell (2003) in his model found negative water values. The hydro dams operators would like to spill water if they could so they can reduce output. For the NZ market Young et. al (2011) found allowing negative water values gave a marginally better fit to the data compared to constraining water values to be positive.

[6] https://www.emi.ea.govt.nz/ Generation and demand data are from the wholesale data set, prices from the wholesale dashboard.

especially estimation of the water value curve or (c); the model not taking into account outages or gas supply disruptions accurately. If the difference is due to (a) then comparing to the actual prices gives a more accurate estimate of market power rents. If the difference is due to (b) or (c) then comparing to the simulated prices will give a more accurate estimate of market power. Our view is that the difference in average prices is likely due to (b) or (c) however other observers quite legitimately may have the view that the difference is along the lines of (a). Thus we present the results using actual prices as well as simulated prices.

# 3 Results

Twelve half hour periods were simulated each day starting at trading period 4, then 8 and so on till trading period 48. Two sets of simulations were run. The first used actual lake levels to establish the water level and the corresponding water value each day. The gas thermal marginal costs for each year are calculated using MIBE (2018) data for commercial natural gas prices and the heat rates for each plant listed in Appendix B, using data from the Electricity Authority and Denne (2017). The heat rates reported by Denne (2017) differ somewhat from those specified by the Electricity Authority as Denne (2017) has corrected for the age of the plants. These simulations give a good estimate of market power ceteris paribus (CP), however over the course of the year we find that the competitive market simulations have a slightly higher capacity factor for the hydro – around 6% higher. This leads to dynamic consistency issues since it is not possible to keep dispatching more hydro forever since at some stage the lakes will run out of water.

To overcome the dynamic consistency problem we also ran a set of more ambitious scenarios where the computer algorithm keeps track of hydro dispatch with the lake levels updated each day using simulated dispatch and actual recorded inflows. This introduces a powerful feedback loop into the competitive simulations. If too much hydro is dispatched in the competitive scenario, compared to the scenarios with market power, the lake levels with competitive dispatch are correspondingly lower which pushes the water value up and reduces hydro dispatch. Over the course of a year this means that the hydro capacity factors for the competitive and market power simulations are similar. Note that there is no reason to expect that the actual lake level trajectory generated by the competitive benchmark should be the same as those generated by the agent based SWEM algorithm. In fact we would expect them to be different (see Philpott et al., 2010). Broadly speaking if the water value is low the marginal cost simulations dispatch as much low cost hydro as possible whereas the computer agent based models hold back some hydro, forcing high cost thermals to generate which pushes up the spot price. With time the lower lake levels seen in the competitive model generate higher water values, which means less dispatch later in the year. The reason why these simulations are more ambitious is that the model now has to accurately track dispatch as well as prices. The result is that the difference between actual average prices and average simulated prices over the 7 year sample vary more than those for the ceteris paribus simulations.

We start off presenting and discussing the simulations for each year before summarising the results. Prices are simple nodal averages that are very similar to demand weighted prices and just a bit higher than producer weighted prices.[7] We report on three sets of results. The first are those from the static or ceteris paribus simulations, the second is the dynamic simulations with average prices and market power rents from all 5 seeds. It turns out that there is quite a bit variation between the simulations for the 5 seeds, however generally one of the seeds gives simulated prices similar to observed – we present these results separately as "best seed" results. The lake level and price path figures for the best seed are presented below with the diagrams for all five seeds relegated to Appendix A.

## 3.1 Market power simulations for 2010

On the whole hydrological conditions were favourable with lake levels above the mean except for March when lower than average lake levels causing prices to spike up. There was a significantly higher price spike in December which seemed to have no clear cause. The Electricity Authority was concerned enough to issue a report (Electricity Authority, 2011) stating that "the publicly available information at the end of November 2010 made it difficult to determine why the wholesale spot price increased so rapidly in December." After further investigation they concluded that the price spike was due to a number of factors, principally uncertainly surrounding hydrology with; an early snow melt; a strong emerging La Niña weather pattern; uncertainty surrounding the planned Maui outage in February 2011; and uncertainty surrounding thermal plant availability. Needless to say our benchmark model CP did not predict this price spike, although of some interest is that the dynamic models did.

New geothermal generation came online in June 2010, with Mighty River Power commissioning a 140MW plant, and the introduction of new 23MW Contact geothermal plant.

### 3.1.1 Ceteris paribus simulations

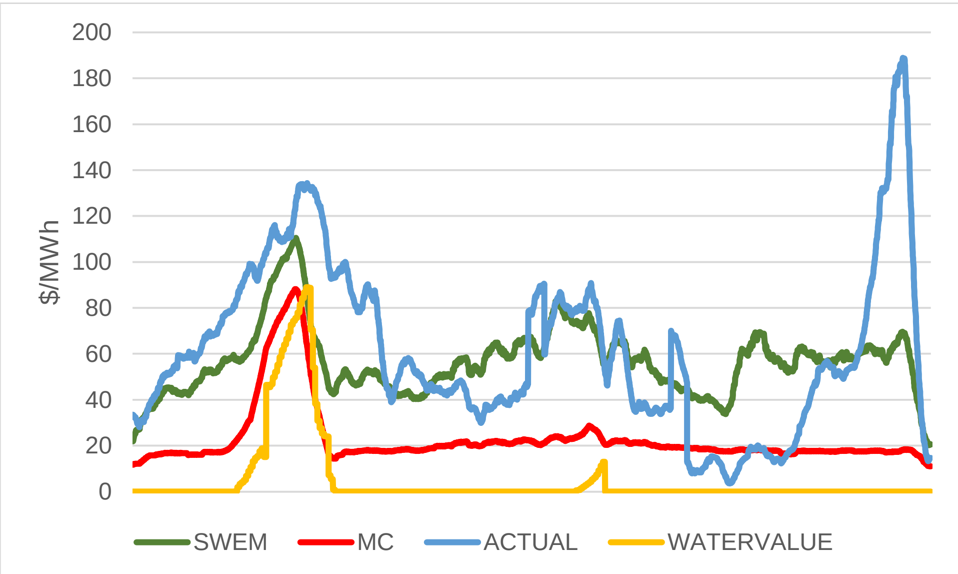



*Figure 1: 2010 Running average 7 day actual and simulated prices and water values.*

[7] The choice was dictated by the scope of the report and the timeframe.

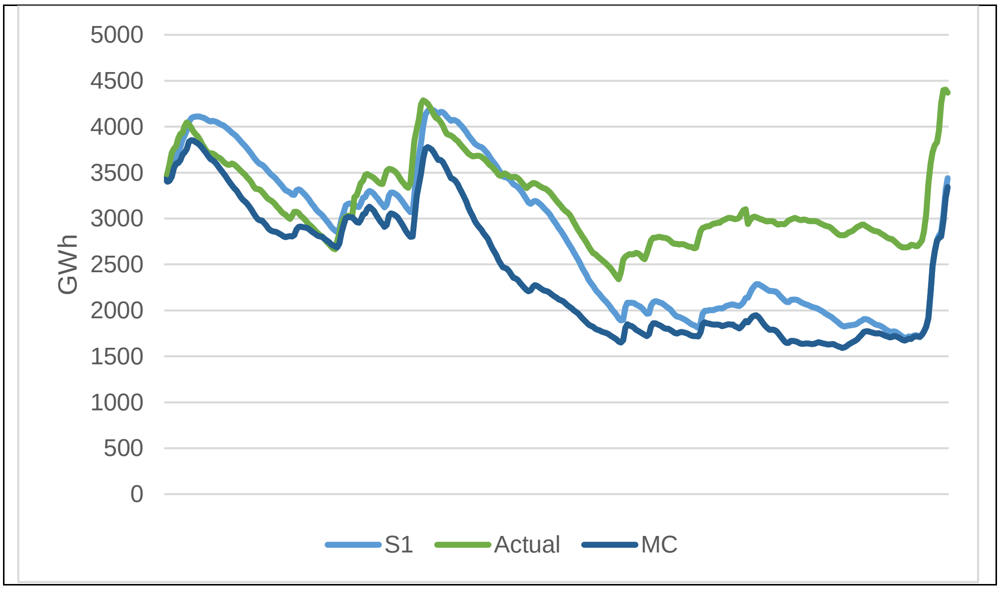
The CP SWEM prices are effective in tracking actual prices until the December price spike discussed above (figure 1). Even so the overall average price predicted of $56/MWh is close to the observed price of $60/MWh. The competitive marginal cost prices are low except for a brief spike in March, Simulated prices and revenues are reported below. Again market power rents are extremely high using this methodology.

*Table 1: 2010: Prices and Market power rents for CP simulations.*

| Actual ($/MWh) | SWEM ($/MWh) | Competitive ($/MWh) | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|---|---|
| 60.1 | 56.0 | 22.7 | 905 | 1279 | 58% | 2179 |

## 3.1.2 Dynamic simulations

Lake level dynamics are quite interesting with simulated SWEM lake levels tracking actual lake levels until September, thereafter remaining constant and below the actual lake levels (figure 2). Going into December lake levels fell further resulting in SWEM predicting successfully the December price spike. Although the cause of the SWEM price spike is somewhat different to the causes identified by the Electricity Authority report it is a reflection of the underlying hydrological vulnerability. For the best seed the predicted yearly average price of $65.5/MWh was close to the observed price of $61/MWh.



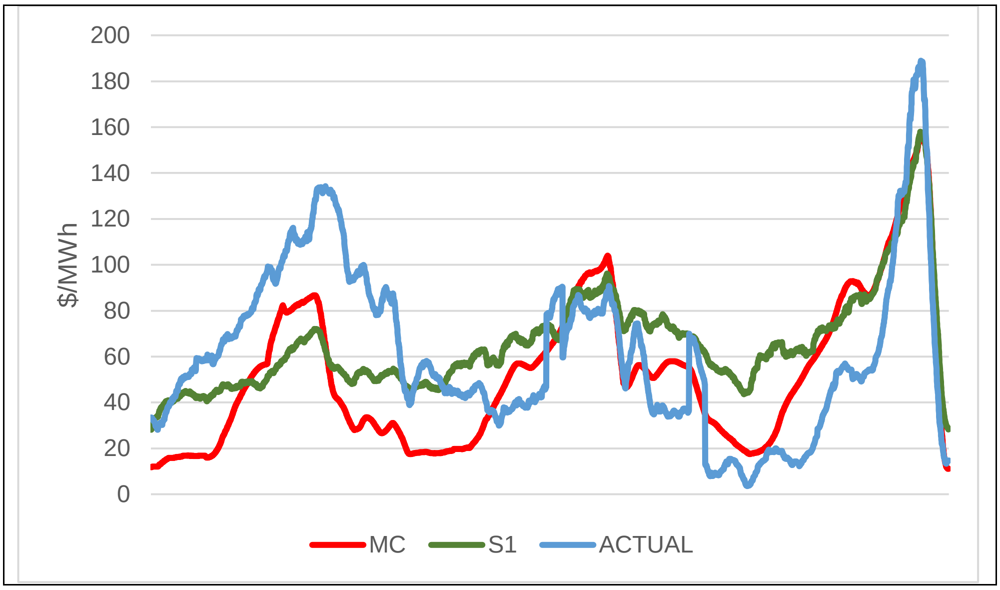



*Figure 2: 2010 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

*Table 2: 2010: Prices and revenues for the dynamic simulations.*

| | **Actual** | **S1** | **S2** | **S3** | **S4** | **S5** | **Average (price/revenue)** | **MC** |
|---|---|---|---|---|---|---|---|---|
| Price ($/MWh) | 61.0 | **65.5** | 70.9 | 82.3 | 103.5 | 72.7 | 79.0 | 52.1 |
| Revenue ($ million) | | 2449 | 2631 | 3026 | 3863 | 3863 | 3166 | 1861 |

Market rents for each of the different approaches can be found in table 3. Rents as a fraction of revenue vary between 24% - 58% - considerably higher than the rents that the Wolak found. If actual prices are compared to the competitive benchmark estimated rents are lower at 15% of revenue reflecting the fact that the simulated prices were about 10% higher than actual prices.

*Table 3: 2010: Market power rents for the different approaches.*

| **Method** | **Simulated Competitive Benchmark Revenue ($million)** | **Simulated Market rents ($ million)** | **% of total** | **Simulated Wholesale Revenue ($million)** |
|---|---|---|---|---|
| CP | 905 | 1274 | 58% | 2179 |
| Dynamic Average | 1861 | 1305 | 41% | 3166 |

| | | | | |
|---|---|---|---|---|
| Dynamic Best Seed | 1861 | 587 | 24% | 2449 |
| Actual Prices | 1861 | 333 | 15% | 2194 |

## 3.2 Market power simulations for 2011

In 2011 asset swaps as proposed by the 2009 Electricity Market Review were enacted. Virtual asset swap contracts mandated by the government had Meridian selling 450GWh/y to Genesis and 700GWh/y to Mighty River Power. There was also a physical swap with Meridian Tekapo A and B transferred to Genesis. In another development the 200MW Stratford gas peaker was commissioned.

### 3.2.1 Ceteris paribus simulations

On the whole simulated prices tracked actual prices accurately except in October they did not spike up as much as observed as hydro lakes ran low and the water value increased (figure 3). Over the course of the year the average simulated price of $58.1/MWh was close to the reported average price of $63.4/MWh.

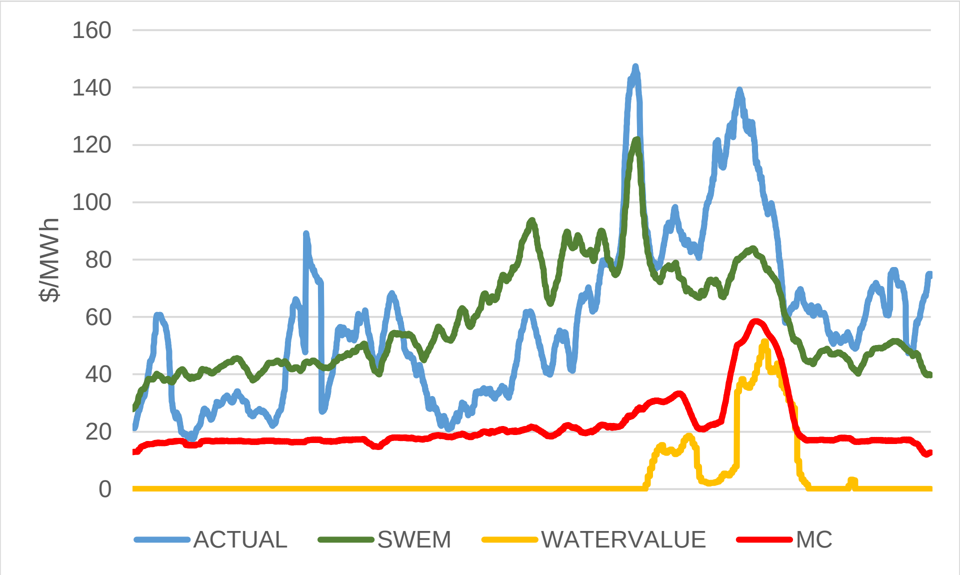


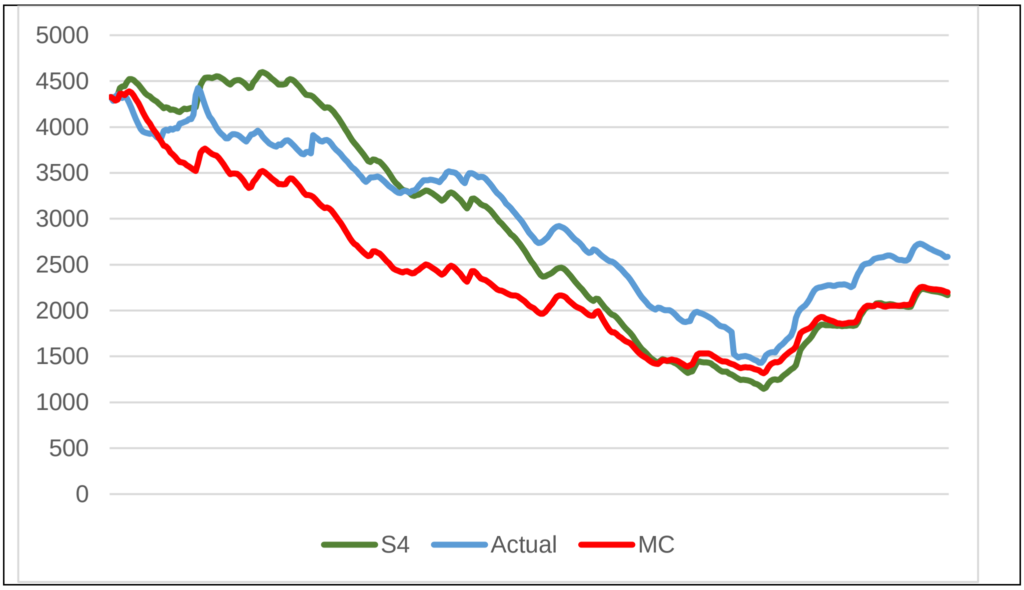

*Figure 3: 2011 Running average 7 day actual and simulated prices and water values.*

*Table 4: 2011: Prices and Market power rents for CP simulations.*

| Actual ($/MWh) | SWEM ($/MWh) | Competitive ($/MWh) | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|---|---|
| 63.4 | 58.1 | 21.7 | 837 | 1410 | 63 | 2247 |

### 3.2.2 Dynamic Simulations

Early in 2011 there were large inflows into the hydro lakes and almost certainly spill. To prevent the simulated lake levels going well above maximum storage capacity the inflows in January were adjusted down by the difference between actual lake levels and predicted lake levels. This meant that at the end of January actual and simulated lake levels were very close. Thereafter both simulated and the competitive benchmark lake levels tracked actual lake levels reasonably closely (figure 4), albeit at a slightly lower level. For the best seed, simulated and actual prices tracked closely. Also of note the lake levels of the best seed at the end of the simulation for the SWEM simulation with market power were very close to the competitive benchmark lake level, as has been the case for 2010.



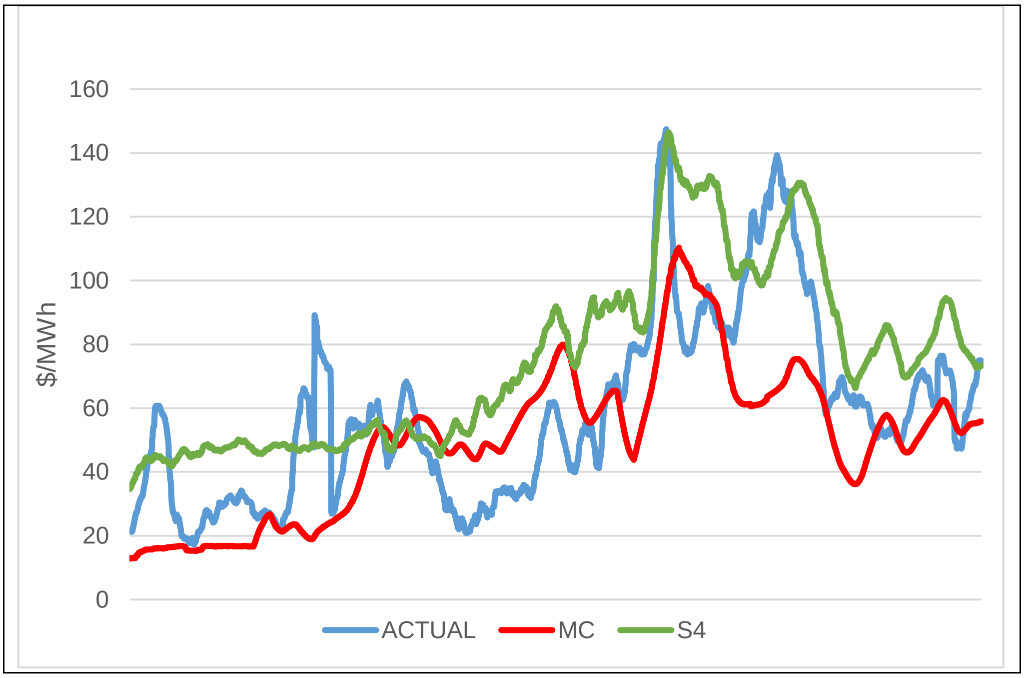



*Figure 4: 2011 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

The results for the different seeds are presented in table 4, with market rents for the different methodologies reported in table 9. Simulated market rents as a percentage of revenue range from 29% to 63%. As above for 2010, comparing the benchmark to actual prices gives a lower estimate of market power rents of around 19%, reflecting that actual prices were lower than simulated prices for 2011.

*Table 5: 2011: Prices and revenues for the dynamic simulations.*

| | **Actual** | **S1** | **S2** | **S3** | **S4** | **S5** | **Average (price/revenue)** | **MC** |
|---|---|---|---|---|---|---|---|---|
| Price ($/MWh) | 63.4 | **67.8** | 81.4 | 83.6 | 64.0 | 84.0 | 76.6 | 49.5 |
| Revenue ($ million) | | 2820 | 3534 | 3266 | 2713 | 3113 | 3089 | 1668 |

*Table 6: 2011: Market power rents for the different approaches.*

| Method | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|
| CP | 837 | 1410 | 63% | 2247 |
| Dynamic Average | 1668 | 1403 | 45% | 3089 |
| Dynamic Best Seed | 1668 | 678 | 29% | 2346 |
| Actual Prices | 1668 | 393 | 19% | 2061 |

## 3.3 Market power simulations for 2012

Inflows for the first six months into the South Island storage lakes were a record low in 2012, so 2012 is certainly a dry year. However, compared to the previous record low inflow year which was 2008 prices did not spike as high and lake levels remained higher. The Electricity Authority's (2012) view is that this may be due to a number of changes in market arrangements. The customer compensation scheme requires retailers to compensate its customers during public conservation periods, which increases the incentive to supply customers. Also a more robust hedge market, and the virtual asset swaps which commenced in 2011, may also have had an impact. Another difference is that inflow into the North Island lakes were considerably higher in 2012 compared to 2008. The changing generation mix with more low marginal cost geothermal is also likely to have had an impact.

October 2012 saw a network upgrade with a new 220kV duplex transmission line from Whakamaru to Pakuranga.

### 3.3.1 Ceteris paribus simulations

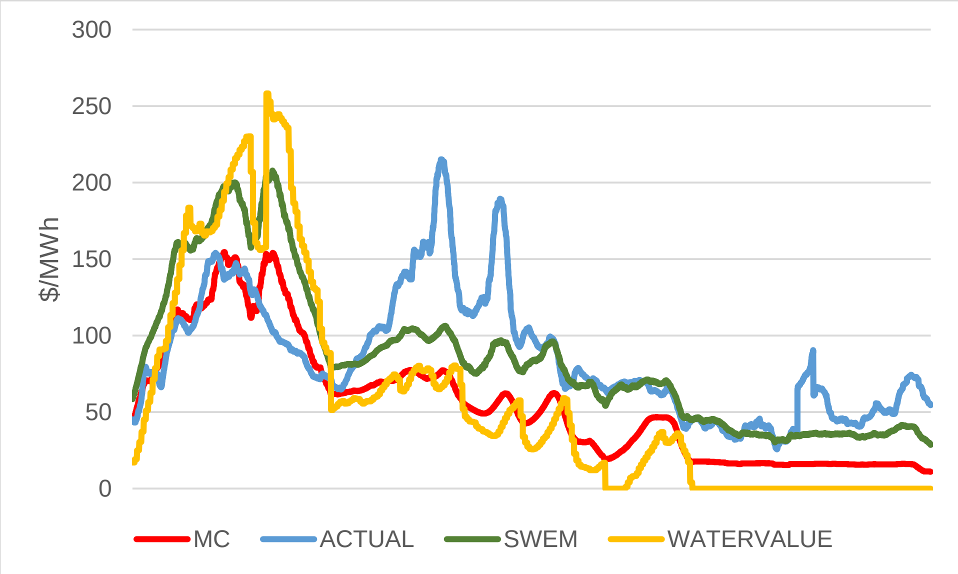



*Figure 5: 2012 Running average 7 day actual and simulated prices and water values.*

Figure 5 shows the SWEM prices track actual prices closely except for a price jump in actual prices from May-June. Part of the reason for these high prices is the high reserve prices in the South Island. The Electricity Authority (2012) has the view that "a big part of this increase was due to Meridian Energy acquiring the offer rights for 165MW of interruptible load from Tiwai smelter in March 2012" which allowed Meridian to exercise substantial market power.

*Table 7 2012: Prices and Market power rents for CP simulations.*

| Actual ($/MWh) | SWEM ($/MWh) | Competitive ($/MWh) | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|---|---|
| 84.8 | 84.3 | 55.2 | 1758 | 974 | 36 | 2732 |

Turning to table 7 we see that the SWEM price is pretty much the same as the actual price. The high water values for much of the year pushes the competitive benchmark price up with the result that rents as a fraction of rents are significantly lower than the "wet" years 2010 and 2011. The SWEM model tends to produce a similar absolute rent each year, which means that in wet years with lower average prices the ratio of rents to revenue is high.

### 3.3.2 Dynamic simulations

Examining the top panel of figure 6 we see that, for the best seed, lake levels for both the SWEM and competitive bench simulations track just a little lower than actual lake levels until the last quarter when observed lake levels jump up. Looking at the bottom panel this doesn't seem to have caused any price separation with the SWEM and actual price tracking close with exception as above when actual prices spike in May - June. Note also that again the SWEM simulation and the competitive simulation end the year with almost exactly the same lake levels and so are dynamically consistent in the sense described above.

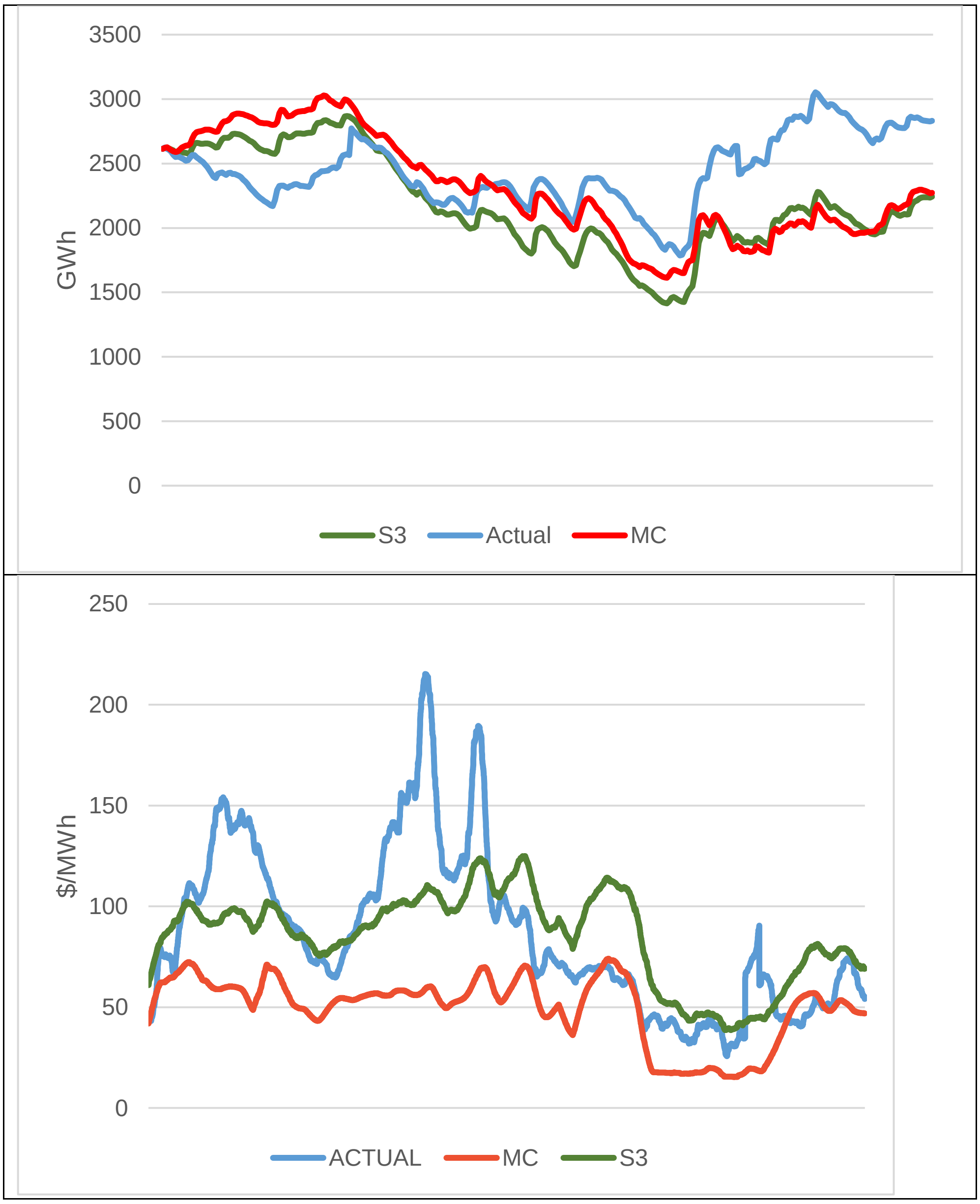



*Figure 6: 2012 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

The price, revenue and market power results are collated in tables 8 and 9. Note that the average price for the best seed is $84.3/MWh which is again very close to the actual average price of $84.8/MWh. Market power rents across the three different approaches are close – varying between 36% and 48% of simulated revenue. Using actual prices gives an estimate of market power rents in the middle of about 41% of revenue. All three simulated prices are very close to actual prices. The relatively small differences in the market rent calculations is mostly due to variation in the distribution of the nodal prices.

*Table 8: 2012: Prices and revenues for the dynamic simulations.*

| | **Actual** | **S1** | **S2** | **S3** | **S4** | **S5** | **Average (price/revenue)** | **MC** |
|---|---|---|---|---|---|---|---|---|
| Price ($/MWh) | 84.8 | 72.2 | 93.5 | **84.3** | 68.3 | 81.6 | 80.0 | 49.4 |
| Revenue ($ million) | | 2419 | 3120 | 2874 | 2346 | 2781 | 2708 | 1500 |

*Table 9: 2012: Market power rents for the different approaches.*

| **Method** | **Simulated Competitive Benchmark Revenue ($million)** | **Simulated Market rents ($ million)** | **% of total** | **Simulated Wholesale Revenue ($million)** |
|---|---|---|---|---|
| CP | 1758 | 974 | 36% | 2732 |
| Dynamic Average | 1569 | 1139 | 42% | 2708 |
| Dynamic Best Seed | 1569 | 1305 | 45% | 2874 |
| Actual Prices | 1569 | 1077 | 41% | 2646 |

## 3.4 Market power simulations 2013

The year 2013 saw large swings in the lake levels over the course of the year with full lakes in January followed by a drought with storage dramatically dropping to 30% below average. Lake levels remained low for most of the rest of the year until high inflows pushed up the level late in the year. The Electricity Authority (2013) observe that “wholesale prices rose and thermal generators stepped up production, allowing hydro generators to conserve water. This is similar to what occurred in the first six months of 2012, which had the worst inflows on record".

Demand continued to remain flat since 2008, despite increasing population growth and GDP growth – generally drivers for higher demand. Although demand remained flat supply continued to increase with significant new geothermal installed during 2013 – Mighty River Power's 82 MW Ngatamariki plant and Contact Energy's 166MW Te Mihi plant. This is on top of the extra 163MW of geothermal added in 2010.

Flat demand and increasing low marginal cost geothermal supply should put downward pressure on prices. We will see below that simulated prices do seem lower for the rest of the study time frame.

### 3.4.1 Ceteris paribus simulations

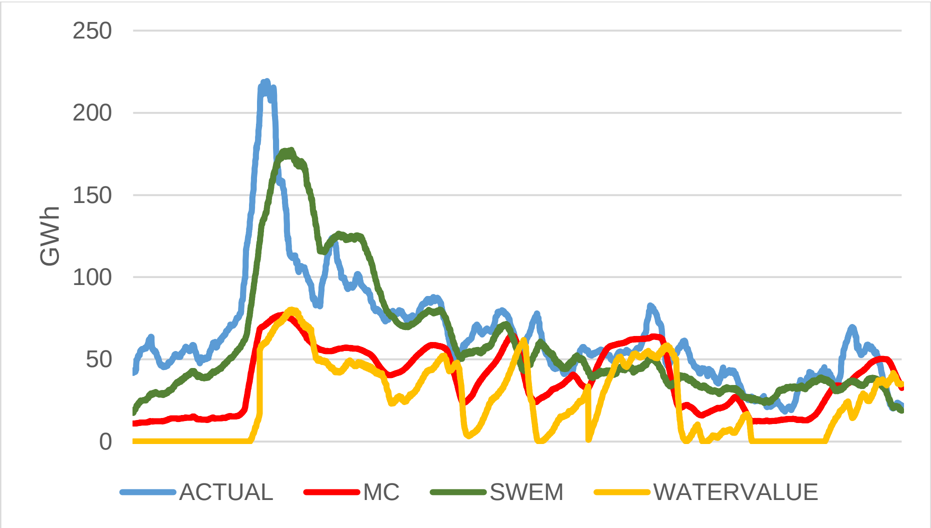



*Figure 7: 2013 Running average 7 day actual and simulated prices and water values*

The simulated SWEM prices CP for 2013 track actual prices closely with the yearly average price of \$59.1/MWh close to the observed price of \$65.9/MWh. Although the water value was above zero for much of the year prices remained reasonably low.

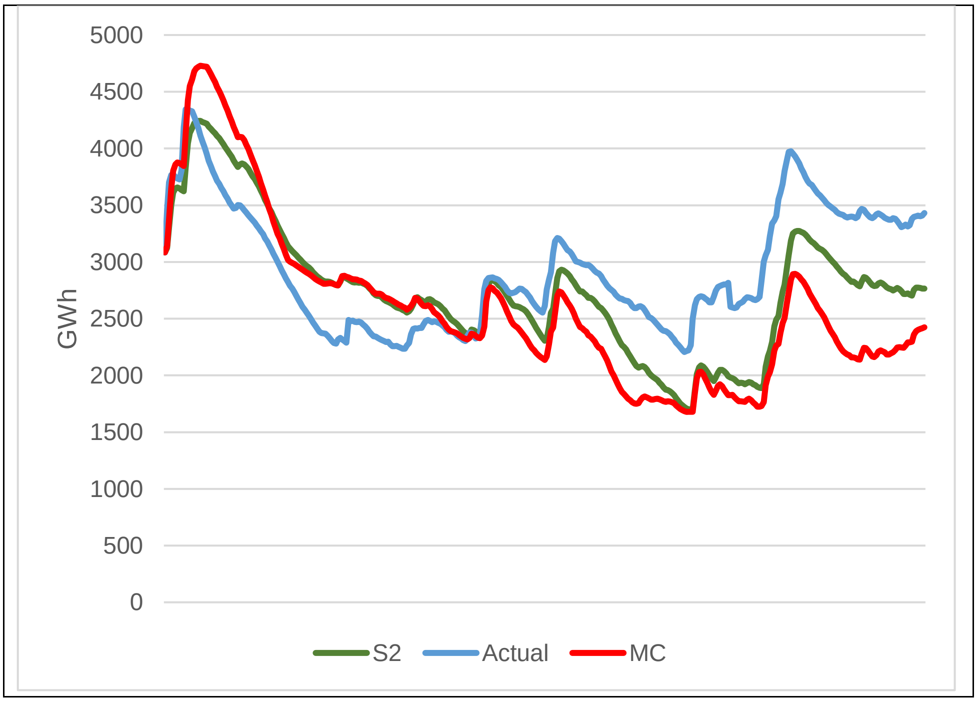
*Table 10 2013: Prices and Market power rents for CP simulations.*

| Actual (\$/MWh) | SWEM (\$/MWh) | Competitive (\$/MWh) | Simulated Competitive Benchmark | Simulated Market rents | % of total | Simulated Wholesale Revenue |
|---|---|---|---|---|---|---|

| | | | Revenue ($million) | ($ million) | | ($million) |
|---|---|---|---|---|---|---|
| 65.9 | 59.1 | 34.7 | 1207 | 710 | 37 | 1917 |

### 3.4.2 Dynamic simulations

Inflows were very high at the beginning of the year so these were reduced, as above, so that SWEM simulated lake levels and actual lake levels were the same at the end of January. Even so the competitive benchmark simulation came very close to exceeding the lake storage limit, which we estimate to be about 4700GWh. After January the SWEM and the competitive benchmark lake levels (top panel of figure 8) were higher than observed which means that the models didn't pick up the price spike seen in the observed data early in the year. The CP SWEM simulation above with water values derived from actual lake levels does pick up the price spike. The water value function is highly non-linear so even modest differences in lake levels can lead to significant differences in prices. For the rest of the year the market power simulated prices track actual prices closely. The relatively lower simulated price spike early in the year leads to lower prices for the best seed – an average price over the year of \$54.4/MWh compared to the actual value of \$64.8/MWh



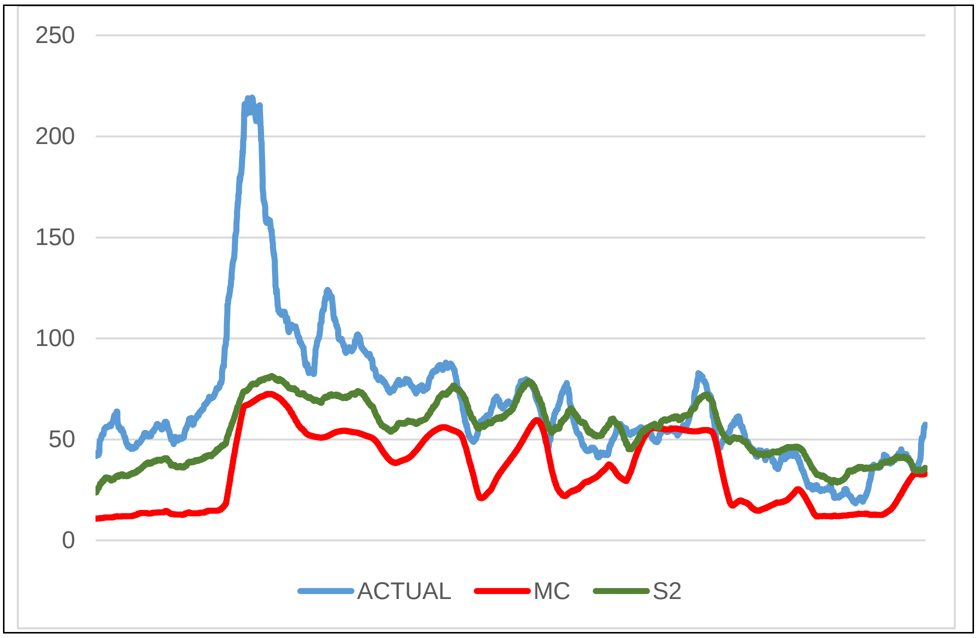



*Figure 8: 2013 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

*Table 11: 2013: Prices and revenues for the dynamic simulations.*

| | **Actual** | **S1** | **S2** | **S3** | **S4** | **S5** | **Average (price/revenue)** | **MC** |
|---|---|---|---|---|---|---|---|---|
| Price ($/MWh) | 65.9 | 45.3 | 52.4 | 46.0 | 47.2 | 46.4 | 47.5 | 35.0 |
| Revenue ($ million) | | 1572 | 1700 | 1635 | 1685 | 1807 | 1680 | 1145 |

Market power rents as a percentage of revenue were very similar for the three different simulation approaches – between 31% to $37%. Using actual prices estimated rents are higher at around 47% of revenue. The main reason for the difference is that simulated prices are lower than actual prices, a trend that continues (as seen below) for all subsequent years.

*Table 12: 2013: Market power rents for the different approaches.*

| Method | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|
| CP | 1207 | 710 | 37% | 1917 |
| Dynamic Average | 1146 | 624 | 31% | 1680 |
| Dynamic Best Seed | 1146 | 544 | 33% | 1700 |
| Actual Prices | 1146 | 1003 | 47% | 2145 |

## 3.5 Market power simulations 2014

Demand continued flat in 2014. Figure 9, reproduced from Electricity Authority (2014a) shows monthly demand for 2014 compared to the average from 2008 - 2013. For the first half of the year demand was less than average, whilst it was higher than average for the last half. Overall demand for 2014 was almost exactly the same as the average over the previous 6 years. Hydro inflows were low until April, which caused low lake levels and a corresponding price spike. The outage of the Maui transmission line in March meant that some thermal plants were unable to operate and put further upward pressure on prices. Prices spike again in August was due to an extremely high price spike as demand was unexpectedly high before South Island hydro supply could cover demand.

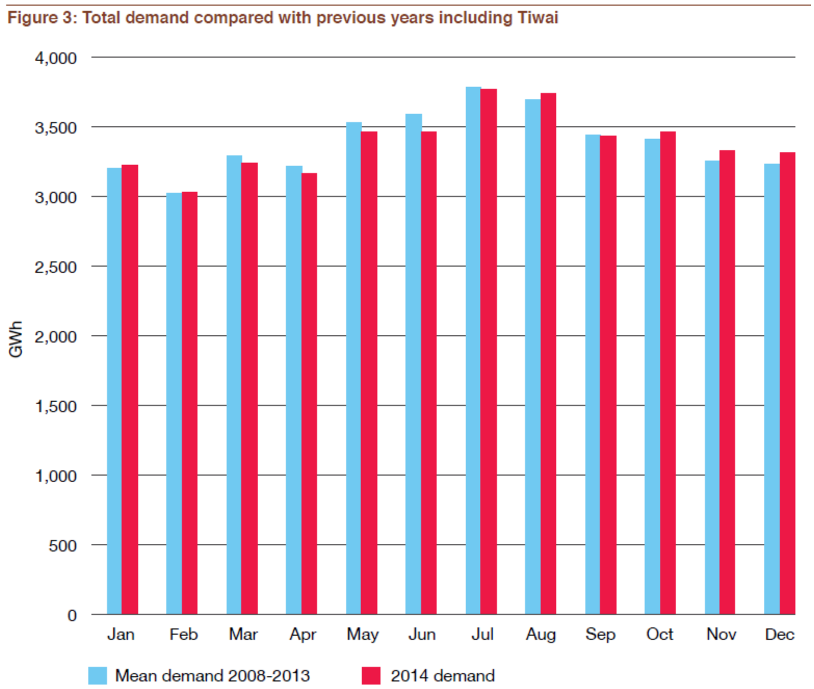



*Figure 9: Demand for 2014 compared to mean demand 2009-2013. Source: Electricity Authority (2014).*

The Electricity Authority also reports that the increase in geothermal generation in recent years has had an impact on the market with gas plants finding it hard to operate profitably. Contact Energy announced in 2013 that Stratford would not be offered during winter and withdrew the 380MW CCGT Otahuhu B plant from the market in August.

### 3.5.1 Ceteris paribus simulations

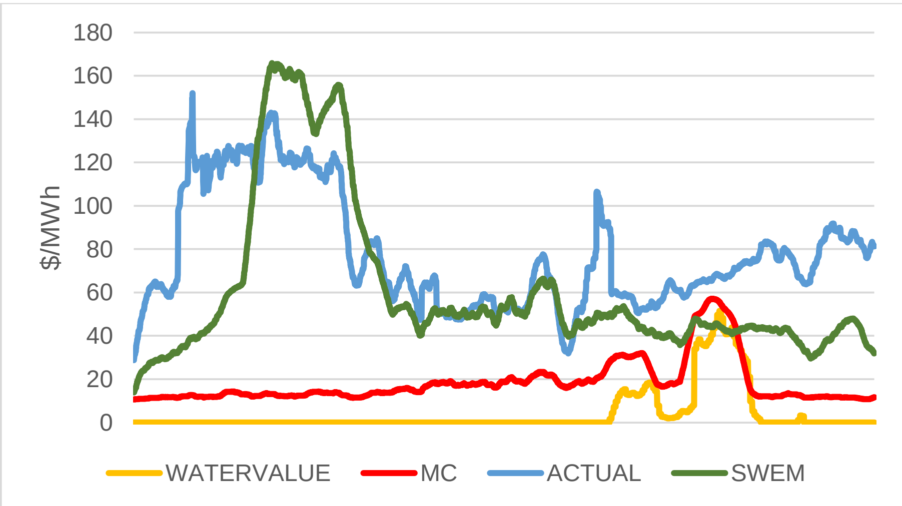



*Figure 10: 2014 Running average 7 day actual and simulated prices and water values*

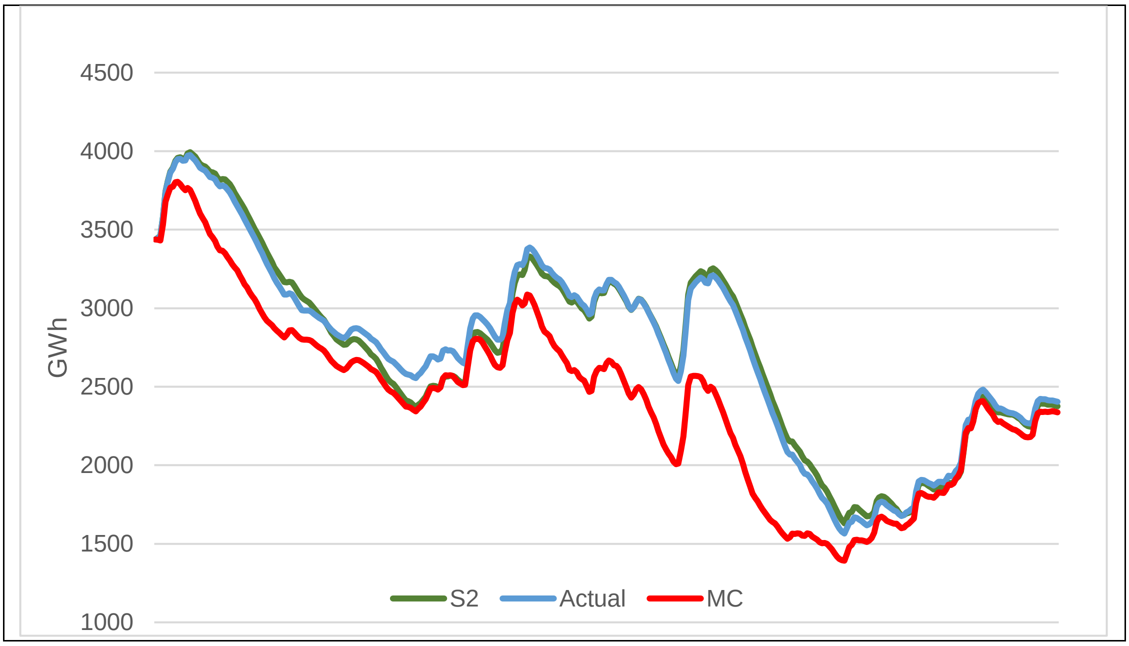
SWEM CP simulations do a reasonably good job of tracking actual prices for most of the year (figure 10). Actual prices spiked a bit early (perhaps due to interruptions of the gas supply in early March) and SWEM did not pick up the August price spike. Simulated prices of $60.3/MWh are again lower than the actual prices.

*Table 13: 2014: Prices and Market power rents for CP simulations.*

| Actual ($/MWh) | SWEM ($/MWh) | Competitive ($/MWh) | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|---|---|
| 76.7 | 60.3 | 18.2 | 605 | 1334 | 69 | 1939 |

## 3.5.2 Dynamic Simulations

Actual and simulated lake levels were remarkably similar over the whole year. Furthermore the water level for both these and the competitive benchmark were all the same at the end of the year. This means that these simulations are particularly important. The fact that market power rents are very similar to other years is a good indication that the results reported here are robust. Since the simulated lake levels are very close to actual ones it is no surprise that the bottom panel of figure 11 looks similar to figure 10.



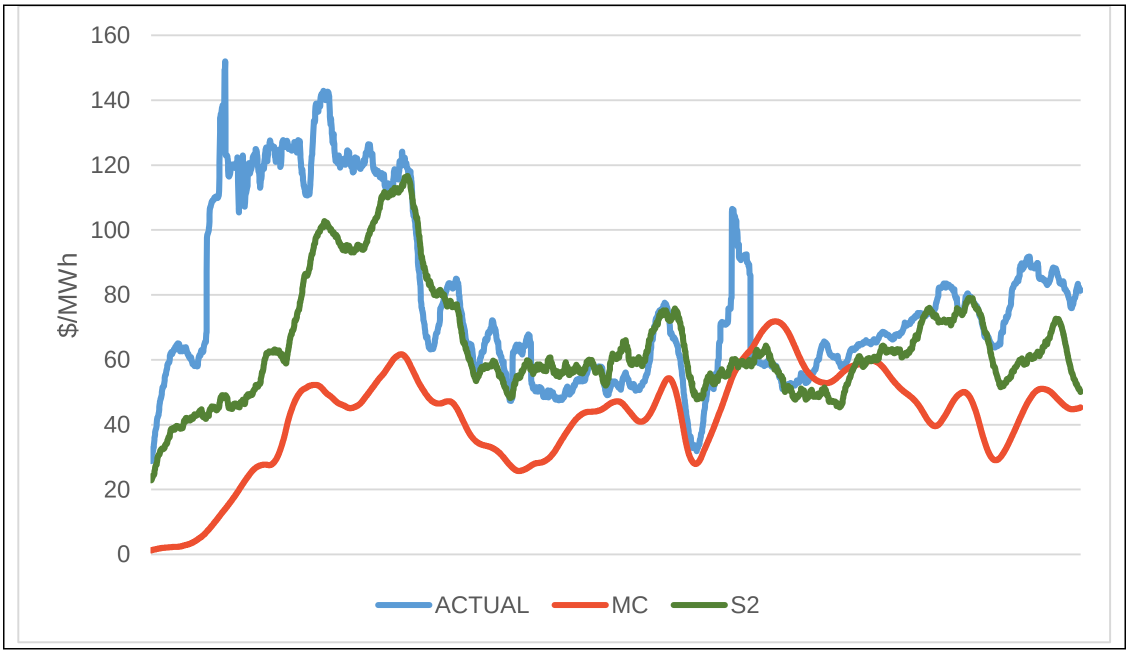



*Figure 11: 2014 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

*Table 14: 2014: Prices and revenues for the dynamic simulations.*

| | **Actual** | **S1** | **S2** | **S3** | **S4** | **S5** | **Average (price/revenue)** | **MC** |
|---|---|---|---|---|---|---|---|---|
| Price ($/MWh) | 76.8 | 54.8 | 63.7 | 55.5 | 57.5 | 60.8 | 61.5 | 43.7 |
| Revenue ($ million) | | 1808 | 2121 | 1868 | 1951 | 2008 | 1951 | 1290 |

Inspecting tables 14 and 15 the take home message is that simulated market power rents are between 34% and 43% of revenue, with market rents estimated using actual prices a bit higher at 47% of revenue.

*Table 15: 2014: Market power rents for the different approaches.*

| Method | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|
| CP | 605 | 1334 | 37% | 1939 |
| Dynamic Average | 1290 | 661 | 34% | 1951 |
| Dynamic Best Seed | 1290 | 831 | 43% | 2121 |
| Actual Prices | 1290 | 1136 | 47% | 2426 |

## 3.6 Market power simulations 2015

The year 2015 started off relatively dry with average prices spiking to $140/MWh at the height of summer. The reduced role of thermal plants noted last year continued. The Electricity Authority report (2015), stated that thermal generation was 26 per cent lower than the average from 2010 - 2014. In their view this is a direct result of increasing low marginal cost geothermal and wind supply. As a result Contact closed Otahuhu B in September (380MW) and the 180MW Southdown plant in December. Genesis announced plans to close the two remaining coal units at Huntly in 2019.

### 3.6.1 Ceteris paribus simulations

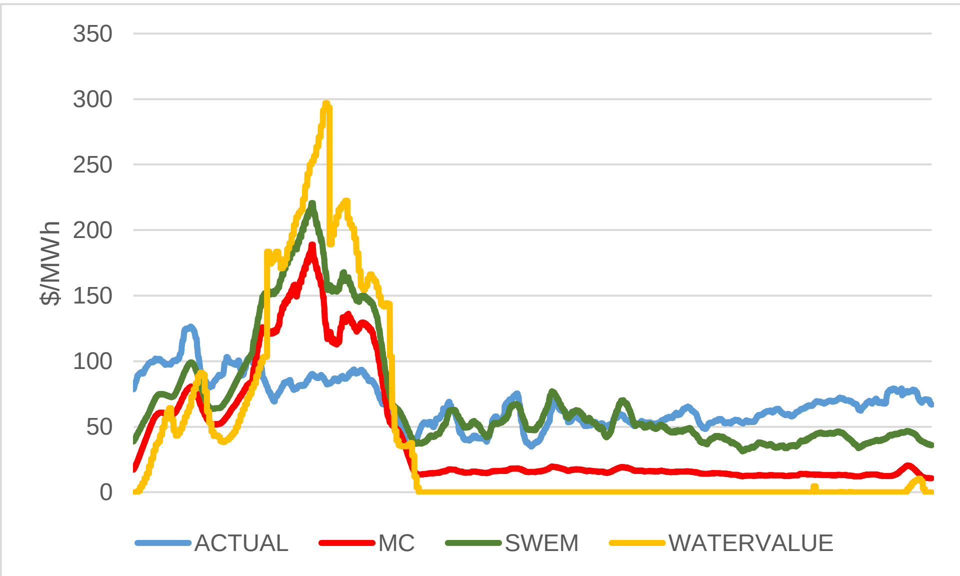



*Figure 12: 2015 Running average 7 day actual and simulated prices and water values*

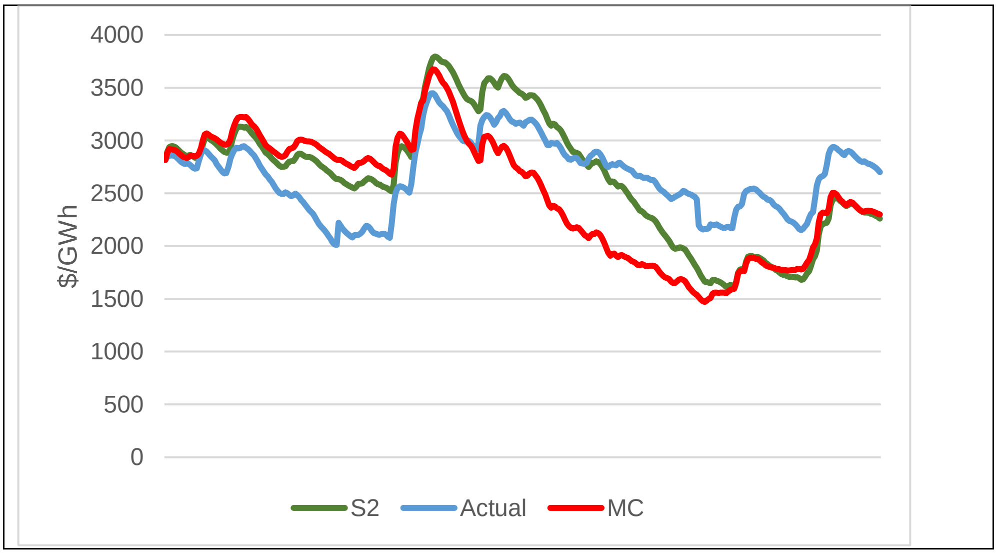
Actual prices were a bit below simulated SWEM prices for a couple of months late summer when the lake levels were low (figure 12). Interestingly they were below the competitive benchmark prices for this period as well! This indicates that the relationship between the water value and the lake level, which was calibrated for 2007 and 2008, may be starting to break down in the face of the significant changes in the generation mix. Nonetheless the average SWEM price of $70.1/MWh is very close to the observed annual average of $69.1/MWh

*Table 16: 2015: Prices and Market power rents for CP simulations.*

| Actual ($/MWh) | SWEM ($/MWh) | Competitive ($/MWh) | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|---|---|
| 69.1 | 70.3 | 41.8 | 1345 | 955 | 42 | 2300 |

## 3.6.2 Dynamic Simulations

A notable feature of the lake level dynamics (top panel figure 13) is that the high water values early in the year meant reduced hydro output and the lake levels remained higher. This paradoxically meant that prices did not spike up as much we saw in the CP simulation reported above. Apart for a period early in the year the best seed dynamic price follows the actual price closely. The annual average SWEM best seed price of $57.4/MWh is below the observed average of $69.1/MWh. Market rents vary between 35% - 45% of revenue for the three different simulation methods. Using actual prices estimated rents are higher at 48% of revenue.



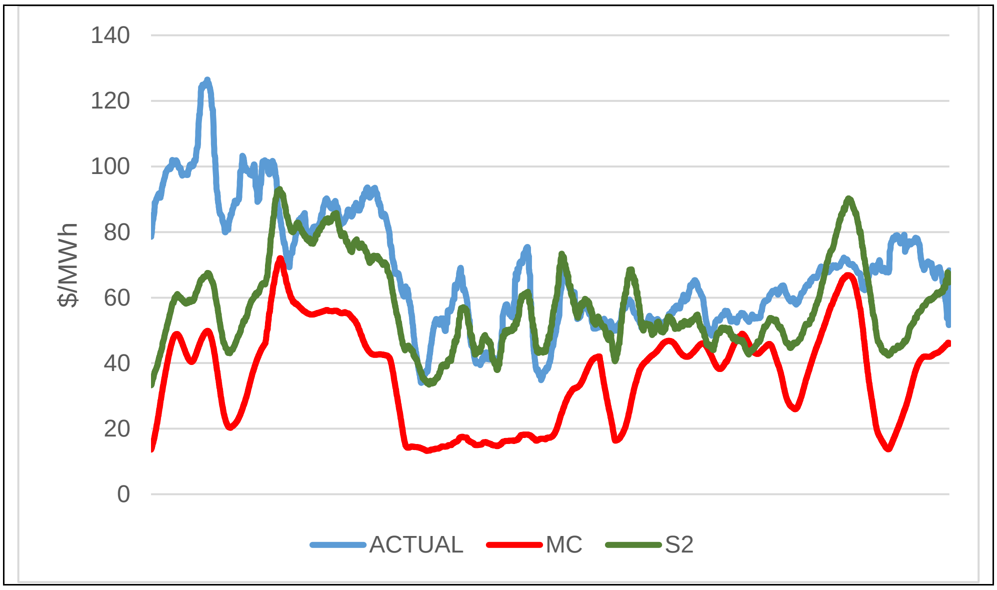



*Figure 13: 2015 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

*Table 17: 2015: Prices and revenues for the dynamic simulations.*

| | Actual | S1 | S2 | S3 | S4 | S5 | Average (price/revenue) | MC |
|---|---|---|---|---|---|---|---|---|
| Price ($/MWh) | 69.1 | 56.3 | 57.0 | 53.1 | 45.6 | 53.5 | 53.1 | 35.9 |
| Revenue ($ million) | | 1825 | 1901 | 1779 | 1505 | 1801 | 1762 | 1142 |

*Table 18: 2015: Market power rents for the different approaches.*

| Method | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|
| CP | 1345 | 955 | 42% | 2300 |
| Dynamic Average | 1142 | 620 | 35% | 1762 |
| Dynamic Best Seed | 1142 | 759 | 40% | 1901 |
| Actual Prices | 1142 | 1044 | 48% | 2186 |

## 3.7 2016 Market power simulations

Lake levels at the start of the year were below average with prices spiking up. Thereafter lake levels were well above average. Of some interest is the price spike of $4000/MWh for a few trading periods on June 2nd. In a subsequent report the Electricity Authority (2017) pointed the finger at Meridian, which was in a net pivotal position on a day with very high demand and little wind generation.

### 3.7.1 Ceteris paribus simulations

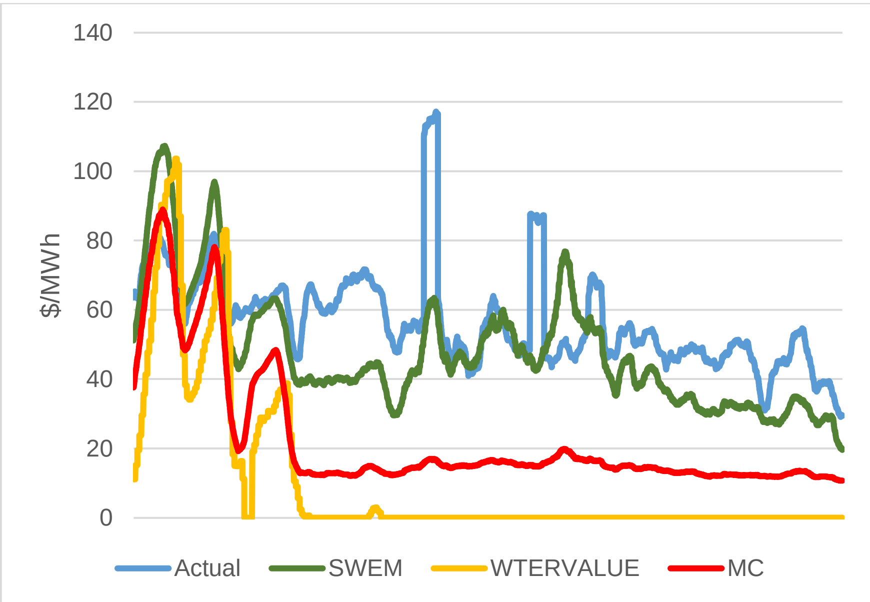



*Figure 14: 2016 Running average 7 day actual and simulated prices and water values*

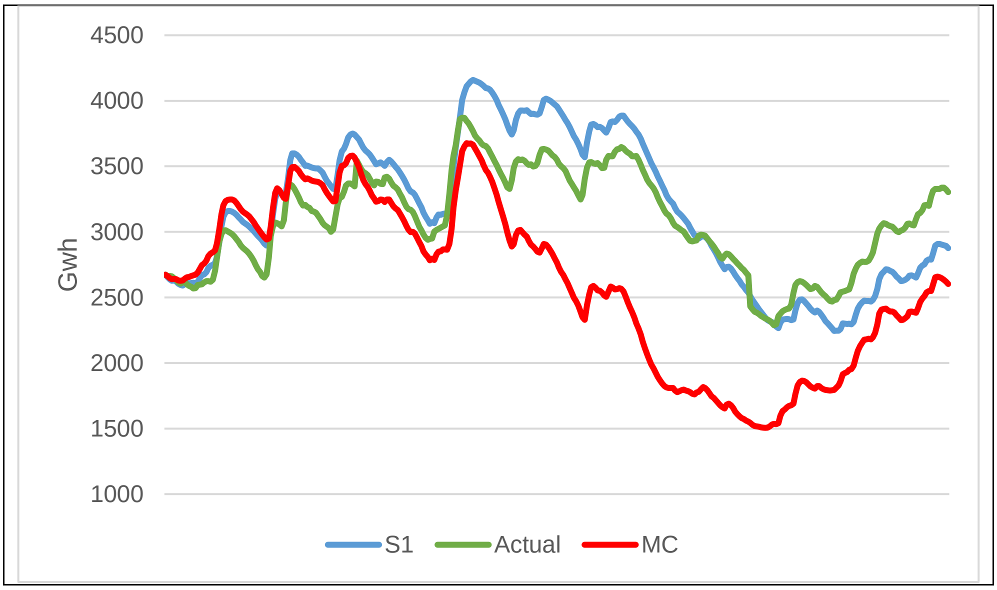
The SWEM CP prices generally track marginally lower than actual prices. There is a bit of a price spike around June 2 but not as high as actually observed, perhaps partly because SWEM prices are set at a maximum of $1000/MWh. As in the previous year the average SWEM simulated price of around $47.8/MWh is lower than the published value of $56.6/MWh. As is not uncommon for a year with low prices the market power rents as a fraction of revenue at 70% are high.

*Table 19: 2016: Prices and Market power rents for CP simulations.*

| Actual ($/MWh) | SWEM ($/MWh) | Competitive ($/MWh) | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|---|---|
| 56.6 | 47.8 | 22.7 | 436 | 1025 | 70 | 1461 |

### 3.7.2 Dynamic simulations

Turning to figure 15 the best seed lake path tracks slightly below the actual path. This pushes the average price up and closer to the actual data.



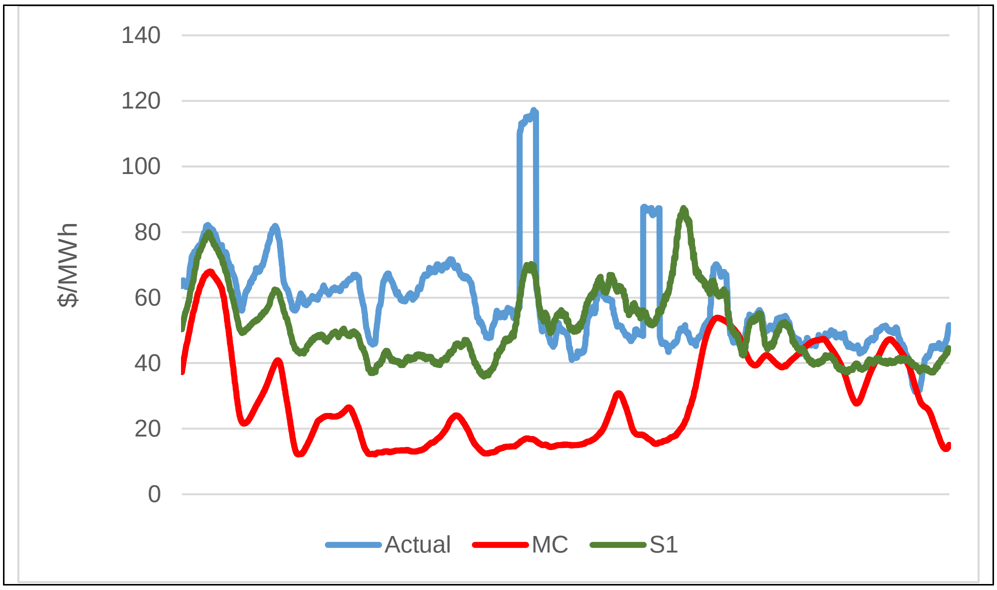



*Figure 15: 2016 Lake levels (top panel) and average 7 day actual and simulated prices for the best seed.*

The best seed average annual price is $49.9/MWh – slightly below that observed of $55.7/MWh. Market power rents for the three different approaches were between 39% - 70%. The best seed estimate of 45% is notably below the estimate using actual prices of 56%.

*Table 20: 2016: Prices and revenues for the dynamic simulations.*

| | Actual | S1 | S2 | S3 | S4 | S5 | Average (price/revenue) | MC |
|---|---|---|---|---|---|---|---|---|

*Table 21: 2016 Market power rents for the different approaches.*

| Method | Simulated Competitive Benchmark Revenue ($million) | Simulated Market rents ($ million) | % of total | Simulated Wholesale Revenue ($million) |
|---|---|---|---|---|
| CP | 436 | 1025 | 70% | 1461 |
| Dynamic Average | 856 | 548 | 39% | 1404 |
| Dynamic Best Seed | 856 | 688 | 45% | 1544 |
| Actual Prices | 856 | 1058 | 56% | 1878 |

## 3.8 An analysis of low demand periods with zero water value

So far we've presented results of the competitive benchmark prices compared to simulated and actual prices. The methodology relies on the simulated prices giving an accurate representation of the market and thus gives confidence that the competitive benchmark is correct. To understand better some of the issues, we focus here on low demand periods during a wet year where our estimated water value is zero. We choose 2011 because for much of the year the water value was substantially below zero in our SWEM model simulations. Of course for the competitive benchmark we do not allow negative water values but the negative water values for the SWEM model are a strong arguments that for most of the year water is abundant. There was a small period in spring where the water value briefly rose to around $40/MWh which we exclude from the analysis.

To illustrate assume that the market consists of just one node. Since we are confident that the water value for the competitive benchmark is zero, the competitive offer curve has must-run hydro and geothermal bidding in at zero as well as any wind. Remaining hydro comes in at $10/MWh, which are the operating and maintenance costs we use for SWEM. The thermal plants follow with offers in between $50/MWh and $300/MWh. Figure 18 illustrates the competitive supply curve ignoring wind, which if blowing would shift the curve to the right. We use the summer network since most of the low demand periods are in summer and ignore line constraints, which of course are there in the full model we use to estimate the counterfactual benchmark. The winter network has more thermal generation, however that shouldn't be relevant. The green curve is the typical demand in the lowest 10% of demand periods. It is very clear from the diagram that the competitive benchmark price should be around $10/MWh during these periods. Because of line constraints and line losses it is actually slightly higher at round $10.5/MWh.

Figure 19 illustrates the actual market price for these very low demand periods with zero water value ranked by demand. For the lowest 10% of demand periods, actual demand varies between 2800MW and 3200MW. Demand peaked in winter at around 6600MW so these demand periods are considerably lower than that. It can be seen that some of the time the price is close to zero which is what we would expect, however for much of the time the price is considerably higher, with a price above $50/MWh not uncommon. The average actual price is $27.6/MWh. It is very hard to reconcile such prices with marginal cost bidding[8]. It may well be the case that for operational reasons the operators of the thermal plants would like to ramp them down to a small output during these low demand periods but in a competitive market the thermals would not be dispatched unless they bid in at close to the marginal cost of the hydro plants. This is clear evidence of market power, even in conditions where the market should be the most competitive.

[8] A small number of the higher price periods may be due to line outages but these are uncommon and unlikely to change the conclusions.

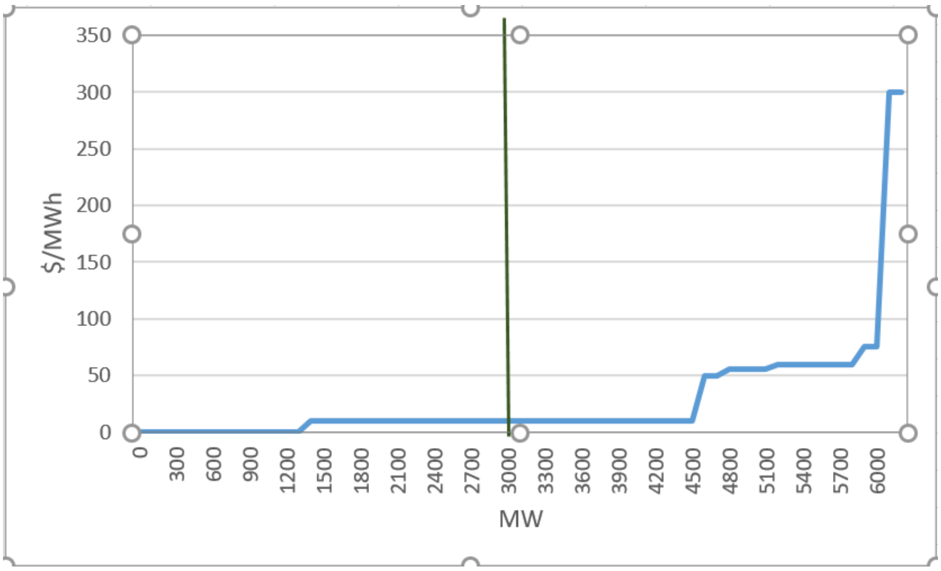



*Figure 16: 2011 Competitive supply curve for the summer network.*

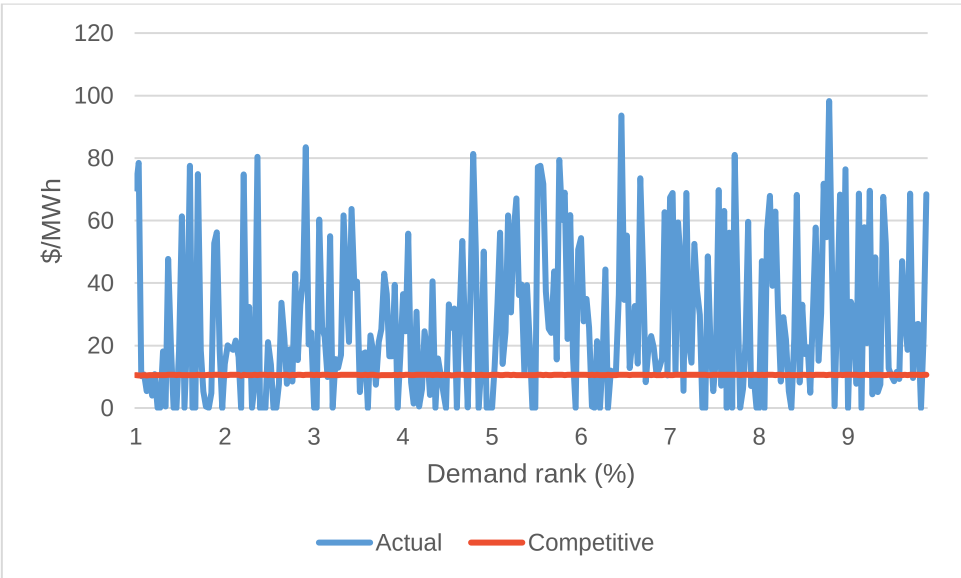



*Figure 17: 2011 prices for low demand periods with zero water value.*

# 4 Conclusions

Having reported in detail on the different methods of simulating market power for each of the seven years 2010-2016, there are some general points that emerge. The first is that all the methods give market rents which are high. The second is how important lake level dynamics are. Ensuring dynamic consistency generally resulted in a large fall in simulated rents. The third point is that nearly all of the simulations tracked actual prices well, with average annual prices typically between 0-$10/MWh of those observed. The SWEM model cannot capture all the complications of actual markets with changing expectations, fuel supply, planned or unplanned outages, and institutional structural changes, so it is remarkable that simulated prices are generally close to those observed.

Of the three different simulation methodologies, we come down heavily in support of the best seed approach for two reasons. The first is that it is dynamically consistent with the lake levels for both the best seed and the competitive benchmark at the end of the year general very close. As argued above we believe that dynamic consistency is crucial. The second is that the simulated prices were generally very close to those actually observed. Table 22 summarises the best seed average price results as well as the CP prices.

*Table 22: Simulated CP, and best seed prices compared to actual (annual averages)*

| Year | Actual | CP | Best See |
|---|---|---|---|
| 2010 | 60.1 | 56 | 65.5 |
| 2011 | 63.1 | 58.1 | 67.8 |
| 2012 | 84.8 | 84.3 | 84.3 |
| 2013 | 65.9 | 59.1 | 52.3 |
| 2014 | 76.7 | 60.3 | 63.7 |
| 2015 | 69.1 | 70.3 | 57.0 |
| 2016 | 56.6 | 47.8 | 49.9 |
| Average | 68.0 | 62.3 | 62.9 |

Averaging all the simulated yearly prices over the 7-year prices we see good agreement with actual prices. The simulated best seed price is just $5.1/MWh below the actual price. The CP price is also close - $5.8/MWh below the observed price. This suggests that the simulation model is not systematically biased. As seen above some years it performs better than others but the close agreement over time means, we believe, that the market power results are credible and robust. Focusing on the best seed the market power rent results are collated in table 23.

*Table 23: Market power rents for the best seed 2010-2016*

| **Year** | **Simulated Competitive Benchmark Revenue ($million)** | **Simulated Market rents ($ million)** | **% of total** | **Simulated Wholesale Revenue ($million)** |
|---|---|---|---|---|
| 2010 | 1861 | 588 | 24% | 2449 |

| | | | | |
|---|---|---|---|---|
| 2011 | 1668 | 678 | 29% | 2346 |
| 2012 | 1569 | 1305 | 45% | 2874 |
| 2013 | 1146 | 554 | 33% | 1700 |
| 2014 | 1290 | 831 | 39% | 2121 |
| 2015 | 1142 | 759 | 40% | 1901 |
| 2016 | 856 | 688 | 45% | 1544 |
| **SUM** | **9532** | **5403** | **36%** | **14935** |

Table 24 presents the market power rent calculations using actual rather than simulated prices. Over the seven year period these average out to be 39% of market income, slightly higher than the numbers from the best seed approach reflecting slightly higher actual prices. Of note is the market power rent calculations for the first two years of the study which are noticeably lower than those calculated for the last 5 years of the study which seems counter intuitive at first sight. The last 5 years saw significant geothermal and wind generation come online during a time when demand was flat. This resulted in lower market prices but not as low as our calibrated model predicted. Indeed during the later years there was exit of thermal generation which partially corrected the supply imbalance. However this means that the high marginal cost plants are being replaced by plants with extremely low marginal costs with the result that our competitive bench mark predicted significant even lower prices with the result that market power rents actually increased. The analysis of section 3.8 suggests that actual prices do not always behave as one might expect during times when the marginal generation costs are very low. For the lowest 10% of demand periods in 2011 with a water value of zero the mark-up of actual prices compared to competitive prices was 59%.

*Table 24: Market power rents using actual prices 2010-2016*

| Year | Simulated Competitive Benchmark Revenue ($million) | ACTUAL Market rents ($ million) | % of total | ACTUAL Wholesale Revenue ($million) |
|---|---|---|---|---|
| 2010 | 1861 | 333 | 15% | 2194 |
| 2011 | 1668 | 393 | 19% | 2061 |
| 2012 | 1569 | 1077 | 41% | 2646 |
| 2013 | 1146 | 1003 | 47% | 2145 |

| | | | | |
|---|---|---|---|---|
| 2014 | 1290 | 1136 | 47% | 2426 |
| 2015 | 1142 | 1044 | 48% | 2186 |
| 2016 | 856 | 1058 | 56% | 1878 |
| SUM | **9532** | **6044** | **39%** | **15536** |

To sum up – over the 7-year period we calculate total market rents using our preferred methodology of $5.4 billion which is 36% of total revenue of $14.9 billion. The market rents that we calculate are even higher than those announced by Wolak.

Our methodology relies on using an agent based model and using accurate cost estimates where possible. We use a simplified 19 node network and a market solver which clears the market based on the offers submitted by the generation firms. We argue that computer agent models have an established track record and that there is a substantial academic literature which demonstrates that they give credible descriptions of electricity markets (Weidlich 2008 and Young et al. 2011). To our knowledge there has not been any substantive criticism of this general approach to modelling electricity markets.

Our approach relies on using accurate network data taking into account line constraints, must-run generation, water-values and the reserve market. We think we have accounted for these accurately but there will always be areas where we could improve the model. One example is the way we have accounted for spinning reserves by de-rating all plants capacity by 12%.

In this report we have introduced a new methodology where we use the calibrated computer-agent based model to simulate electricity prices each period whilst updating water levels using inflow data and modelled dispatch. We have shown that this approach is dynamically consistent with simulated prices and lake level paths close to the actual. We believe that this is the first time such a model has been developed using a computer-agent based model. Analysing market power in hydro systems is notoriously difficult as seen here. We believe our approach is an important contribution to understanding how to approach this.

As discussed above, the prevailing view of government is that market power results reported by Wolak (2009) used a flawed and hence market power is not an issue in the New Zealand electricity market (Treasury, 2012; MIBE, 2009; Leyton, 2013). The Electricity Authority's view is summed up by Leyton (2013). We consider each of the critiques in turn. The first of these is that the opportunity cost of hydro storage, that is the water value, is underestimated. We agree with this as discussed extensively above. Our approach relaxes the constraint that the water value is capped at the thermal marginal cost and sees at times water value substantially higher than the maximum suggested by Wolak. Our approach comes close to reproducing actual prices when lake levels are low, which gives us confidence that water values are accurately estimated.

The second critique by the Electricity Authority is that the Wolak report failed to take into account the availability and opportunity cost of gas. We haven't done so either and at times this may have influenced our results such as in March 2012 when prices spiked up due to disruption of the Maui pipeline. Our market-power simulated prices didn't pick this up, but this was also true of the competitive benchmark model. Because our methodology takes the difference in prices between the benchmark and simulated prices, errors such as these, will to a large extent. net out to close to zero.

The third argument (Leyton, 2013, p8) is that "the 'competitive benchmark' price based on short run marginal costs used by the report to calculate market power rents are not sufficient to cover the costs of building new capacity and ensuring security of supply. The additional costs of, for example, payments to generators to provide capacity have been missed from the calculations." That is, the argument is that market power calculations should not focus on SRMCs, but instead LRMCs[9]. As noted above, in the economic literature, almost without exception, market power rents are calculated by looking to see if prices are above the SRMC competitive benchmark.

If our results are accepted it seems that the prevailing view of the New Zealand regulators is that market power rents are needed for firms to recover investment costs. For some industries with marginal costs substantially below average costs this is well established. The regulatory response in this case may well be to regulate prices so that the price equals average cost. However standard electricity market theory is that this is not the case for Energy Only electricity markets (Stoft, 2002). Pricing generation at marginal price with price spikes when supply and demand are close allows for cost recovery for all types of generation and zero economic profits. Price spikes are a regular feature of the NZEM and there is no price cap so there is good reason that the missing money problem should not be as severe as in other markets. Typically in the NZEM cost recovery is aided by extremely dry year events such as 2008 when average prices are substantially above LRMC. So it can be a bit misleading to focus on prices in a given year or given period of years given that these dry year events are infrequent.

The view that market power rents are needed in electricity markets to cover investment costs is one that we haven't seen expressed by regulators in other electricity markets. For example the North American markets have extensive regulation to try and get SRMC's down to the competitive benchmark. For instance, as discussed above, the PJM market uses the three-pivot test. If the combined offers of the three largest suppliers are pivotal their offers are reduced by the market oversight authority to cost based bids (Crampton, 2017).

The argument can of course be turned on its head. Market power rents in the New Zealand market may have encouraged excessive investment that has led to an oversupply of capacity. If prices were closer to SRMC then in the long run there would be less investment and more price spikes, which would be more efficient. Recent years have seen a rebalancing of the market with thermal plants exiting and more retirements on the horizon so it may well be that over the next decade prices will be closer to or higher than LRMC, partly due to market power rents.

Another argument is that "the analysis is done in hindsight, and assumes perfect foresight on the part of decision-makers, with no allowance for the uncertainties parties face in the real world regarding future demand, plant availability and hydro inflows" (Leyton, 2013 p8). To the extent that we have not taken outages and uncertainties of future plant availability into account the argument has some merit. However again, as we take the difference between simulated and benchmark prices, any errors will be common to both and hence mitigated. The more important point, regarding hydro inflows, is taken into account by our methodology that keeps track of lake levels throughout the year using actual inflows and water values which will reflect uncertainty regarding future inflows.

[9] See Electricity Authority (2014b) for estimates of LRMCs.

Another point made (Leyton, 2013, p8) is that “the analysis uses actual demand to estimate the competitive benchmark price in dry years, which ignores demand response to high wholesale prices and biases the competitive benchmark price in the study downwards”. Whilst it is true demand is inelastic in our model, actual demand elasticity is very low (Castalia, 2007). Furthermore, as above, any bias will be the similar for the benchmark as well as simulated prices.

Many of the critiques of the Wolak report are in our view tenuous and are used to justify the prevailing market arrangements. In particular no attempt is made to quantify the market impact of the critiques. Instead they are used to dismiss the Wolak findings in their *entirety.* Our methodology, which uses fitted water values and demands dynamic consistency in the lake levels over the course of the year for the benchmark and market power simulations, directly addresses the substantive critique of the report. In our view the other critiques are not substantial. None-the-less they are mostly taken into account by our methodology, which calculates market power as the difference between competitive and simulated prices, which nets out to a large extent any errors in marginal cost estimations. We also note that Philpott and Guan (2013) using a different methodology to the work here, which addresses many of the points made above, also find substantial market power rents.

There are a number of ways we could improve the modelling. The most obvious would be to construct detailed networks for each time period along the lines of Browne et al. (2012). We did this to some extent by having summer and winter networks but clearly this is second best. Another way would be to run the dynamic simulations with more seeds to get a better estimate of average prices – time constraints precluded this as an option. Another would be to treat spill more accurately. More computing power would allow the SWEM model to offer in several tranches for each plant, except for Huntly each generator offers all its capacity at a fixed price. A more sophisticated model would co-optimise both the reserve and spot price bid for each firm. One possible criticism of the competitive benchmark approach used here is that it doesn’t take into account the dynamics of start-up costs for thermals. Whilst there is some merit in this argument we believe that it is not important for the New Zealand market for two reasons: the first is that thermal generation is a much smaller fraction of generation than many other markets; the second is that examining the generation dispatch files provided by the Electricity Authority it is clear that the main thermal plants do not incur start-up costs as they are operating nearly all of the time, backing off generation during low demand periods but still operating.

Another way the modelling could be improved would be to recalibrate the model. Although the model does simulate market price reasonably well the changing market conditions such as the increase in hedging contracts[10] may mean that it would be useful to recalibrate the SWEM model parameters as well as the water value curve. This we leave for future work however the close agreement between average simulated market prices and actual prices means that we wouldn’t expect the results to change considerably. Indeed changes in the water value function would be in large part netted out in the approach we prefer using the best dynamic seed. For example a small increase in the water value (say less than $5/MWh) would increase the competitive benchmark price and the SWEM price. There would be some change in market rents as a fraction of income but these would not be high. Large changes in the water value function would almost certainly give simulated prices significantly different to those reported here and hence to actual prices.

[10] The Electricity authority report that hedging contracts have doubled over this period.

The focus of this paper has been on market power in the wholesale market. We conclude with a few remarks about the link between the spot price and the retail price. In the short term some customers on real-time price contracts will be paying higher prices than they would if prices were competitive. However customers on fixed price contracts, most of the market, would see no change in prices. However in the long run it is hard to see that the retail price is not benchmarked to some extent to the average spot price. New Zealand is a gross-pool market so the retail part of the gentailers have to buy at the spot price. Poletti and Wright (2018) develop a Cournot model of market power with some customers on real-time prices and some on fixed-price contracts. The model assumes perfect competition in the retail market and examines the long-run equilibrium, so that supply adjusts to changing market conditions. In their model the fixed price charged to traditional customers is a weighted average of the spot price. If the retail market in New Zealand is competitive than the implication of their model is that there will be a pass through of market power rents to higher retail prices.

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# Appendix A. Water values and prices of all 5 seeds for dynamic simulations

## A.1 Dynamic simulation figures for 2010

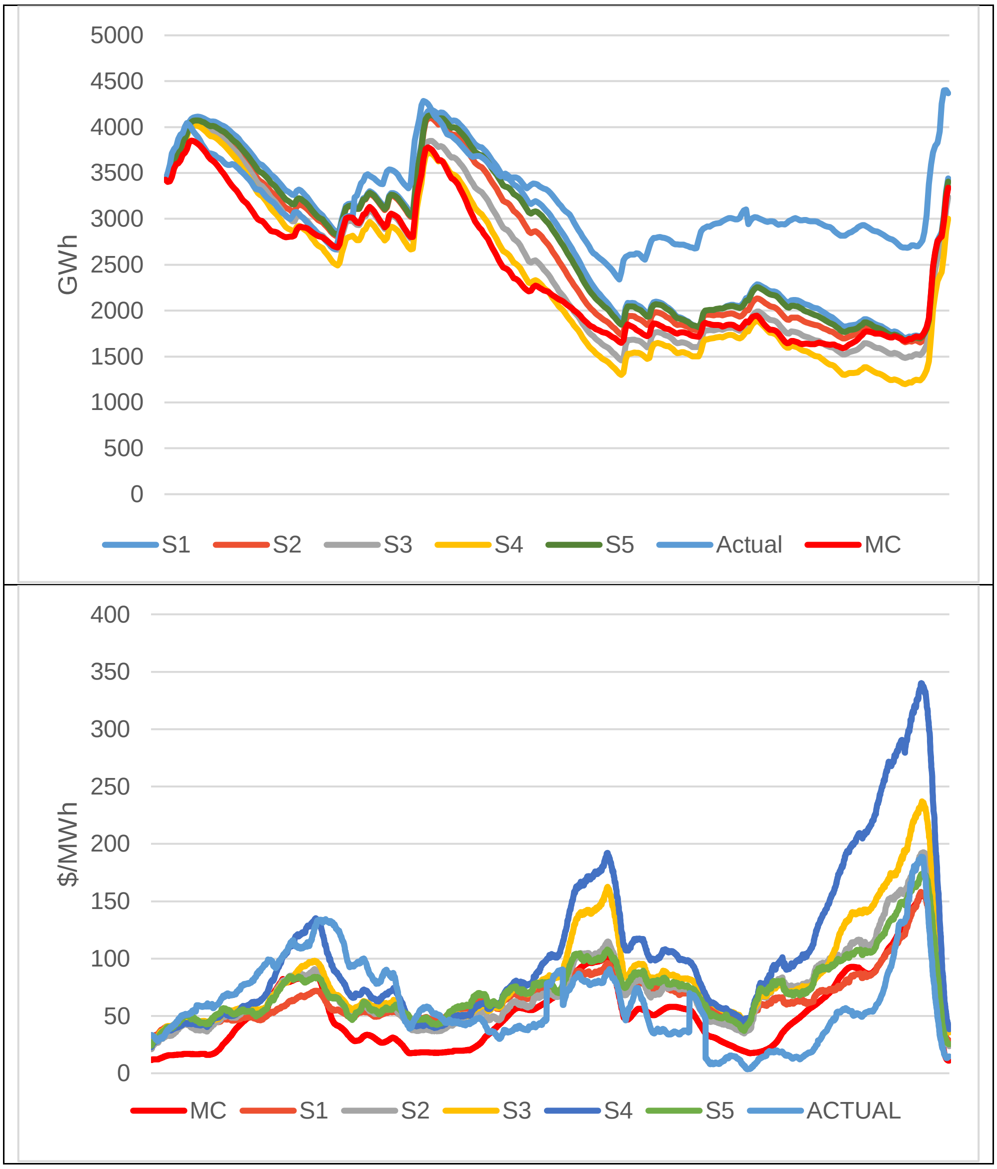


*Figure A 1: 2010 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

## A.2 Dynamic simulation figures for 2011

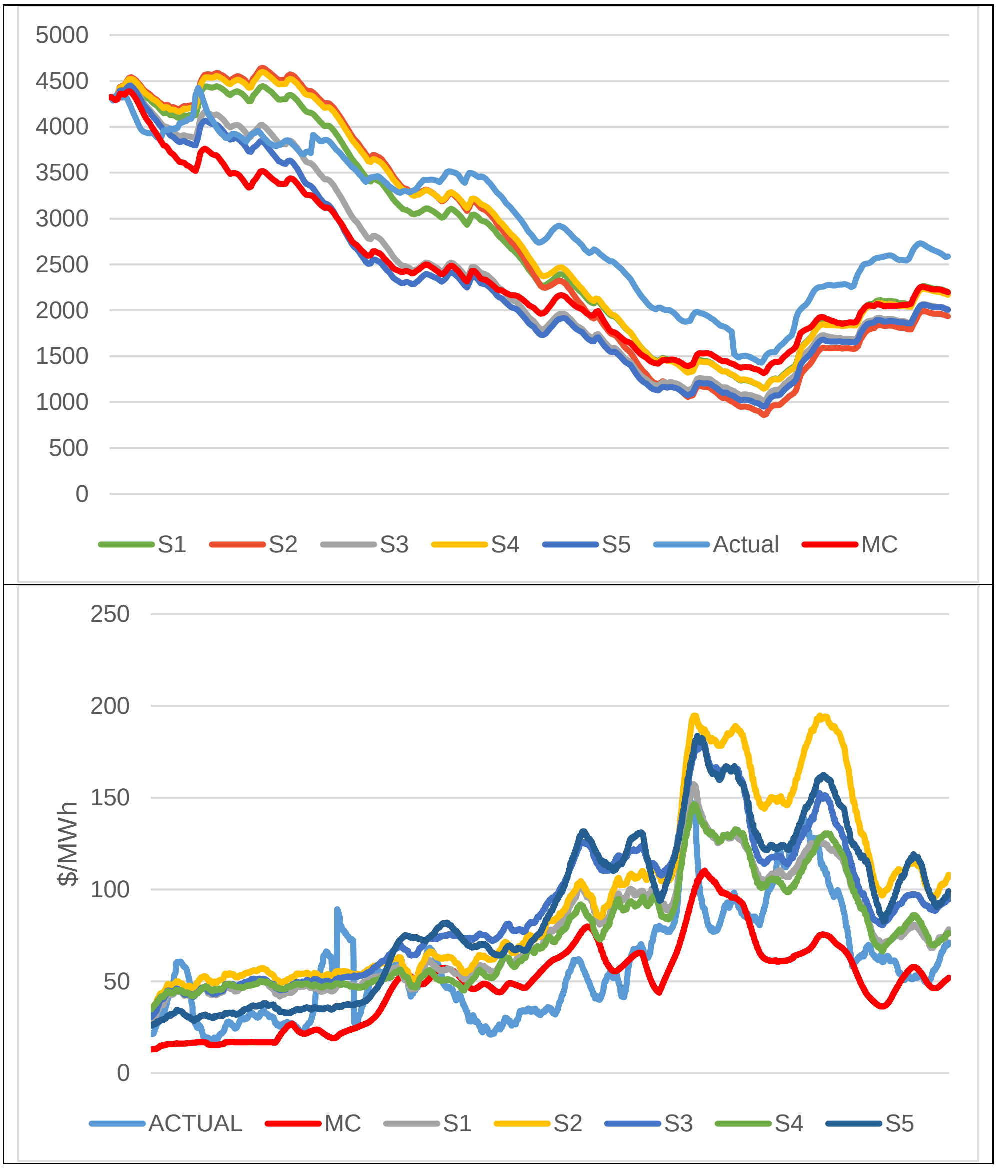


*Figure A 2: 2011 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

## A.3 Dynamic simulation figures for 2012

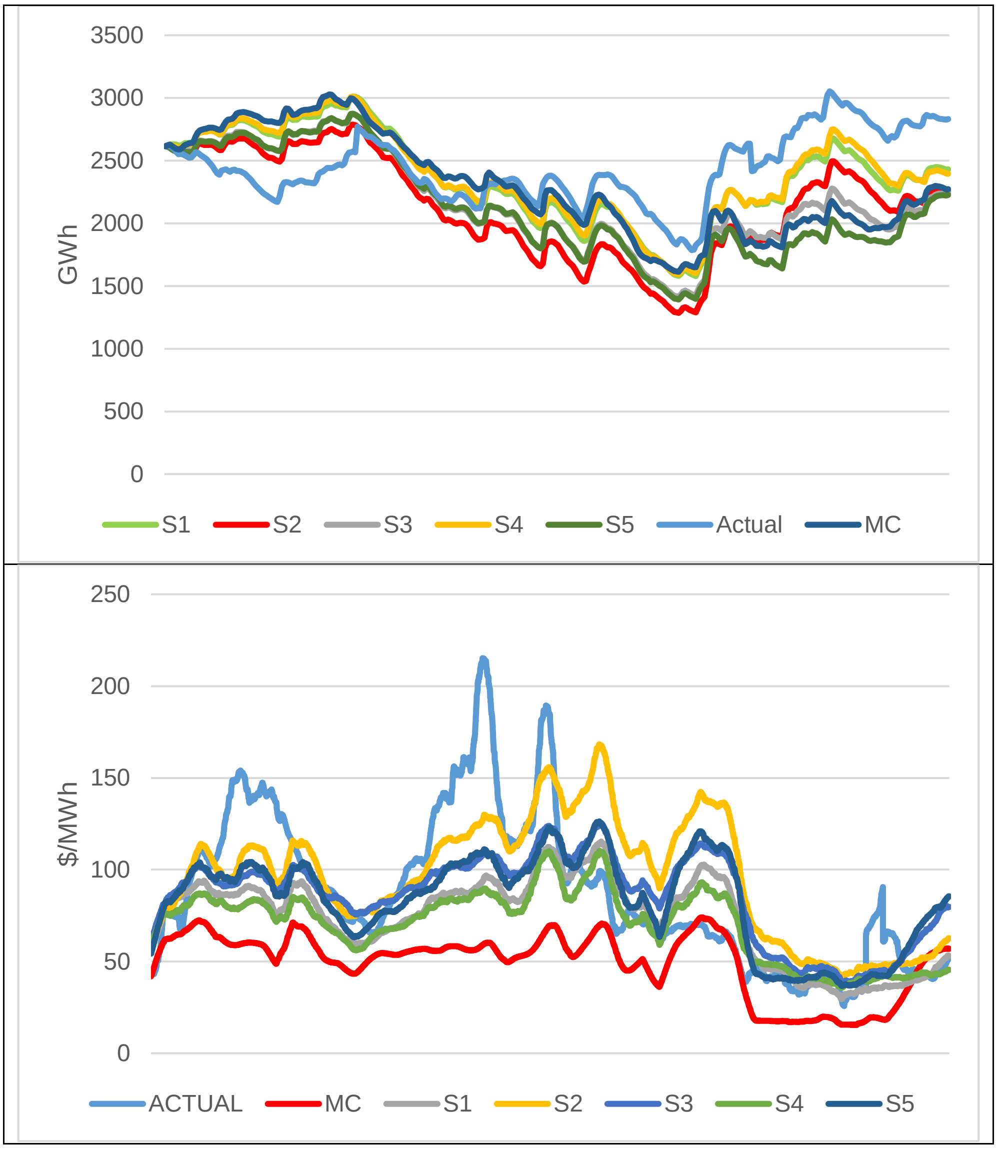


*Figure A 3: 2012 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

## A.4 Dynamic simulation figure for 2013

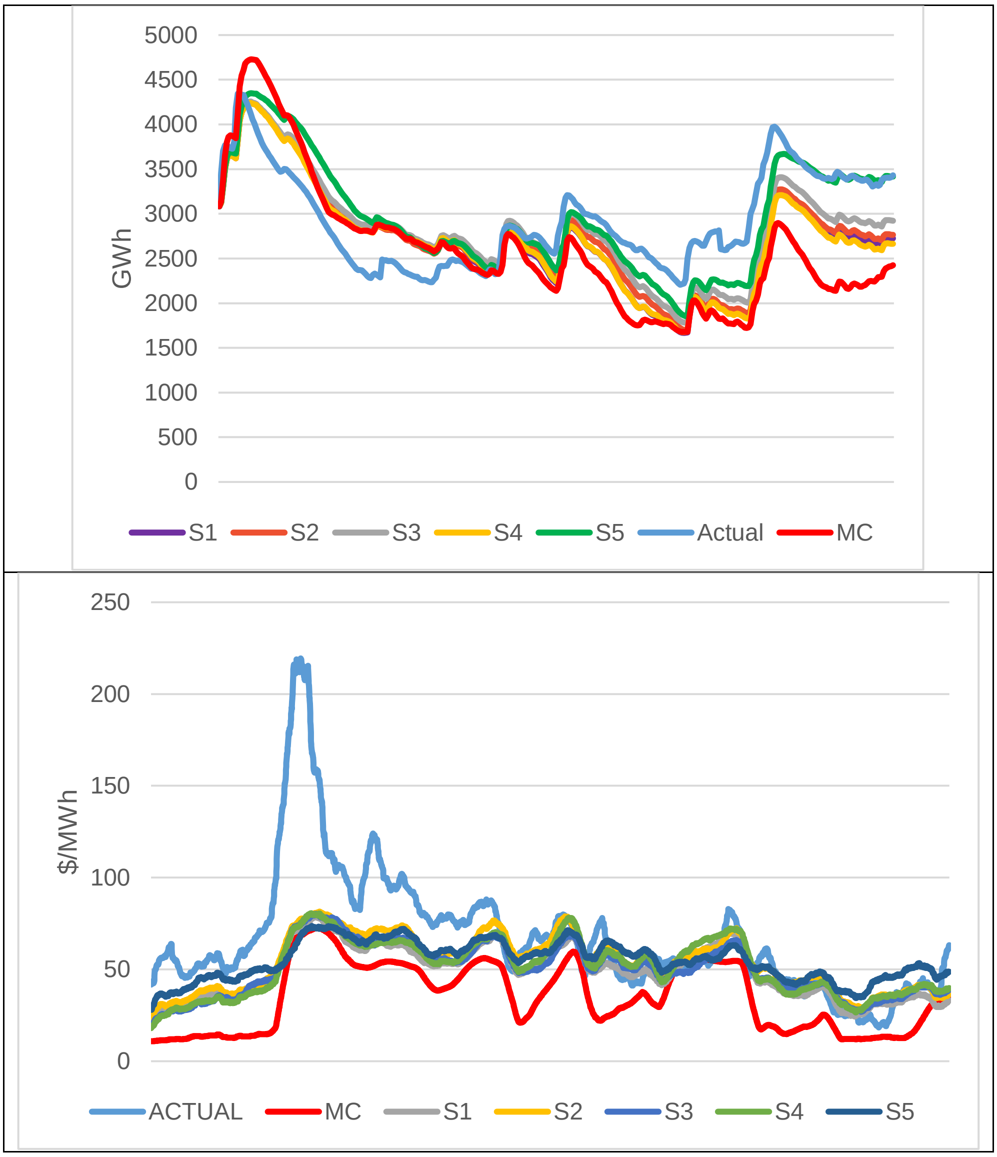


*Figure A 4: 2013 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

## A.5 Dynamic simulation figures for 2014

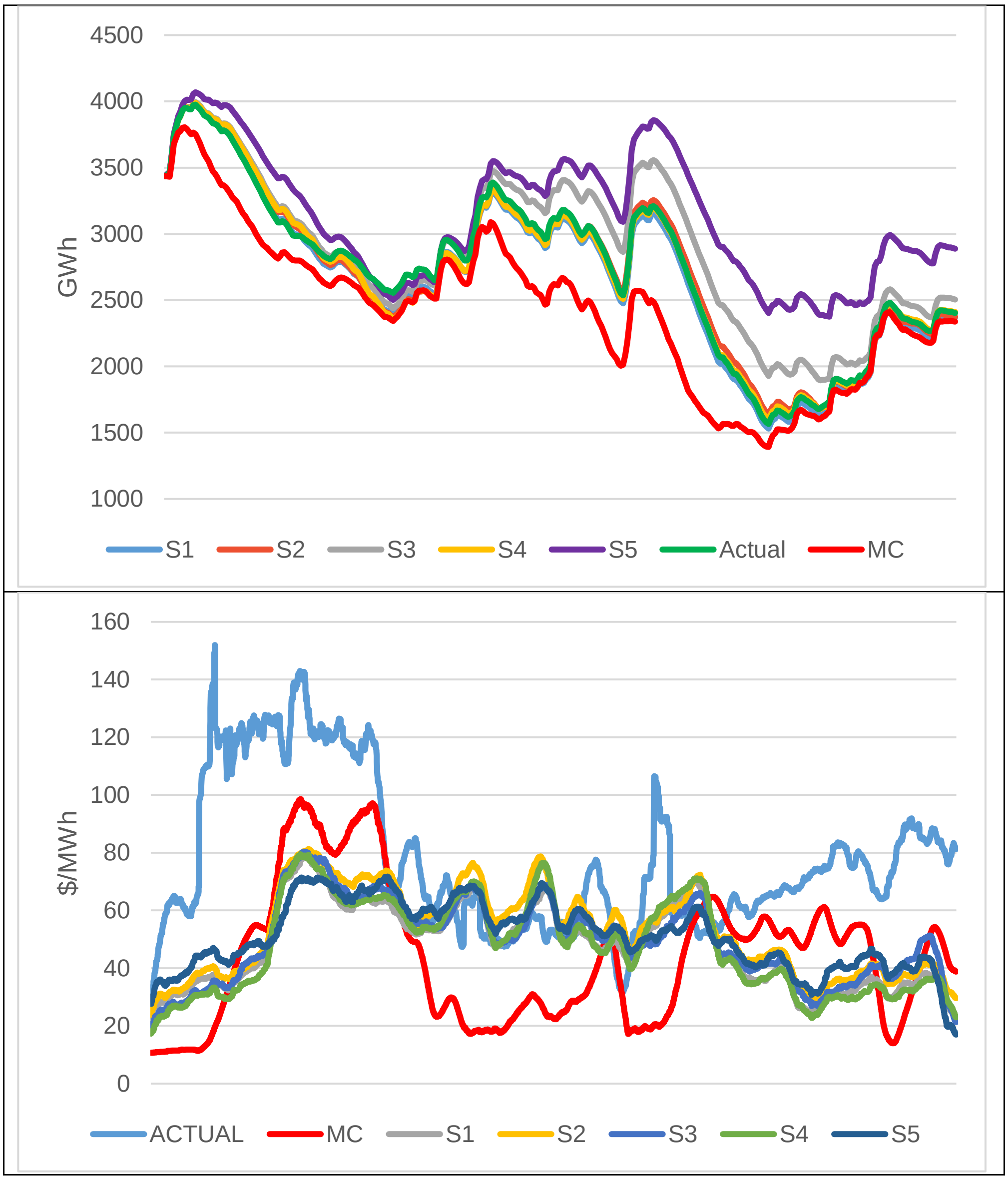


*Figure A 5: 2014 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

## A.6 Dynamic simulation figures 2015

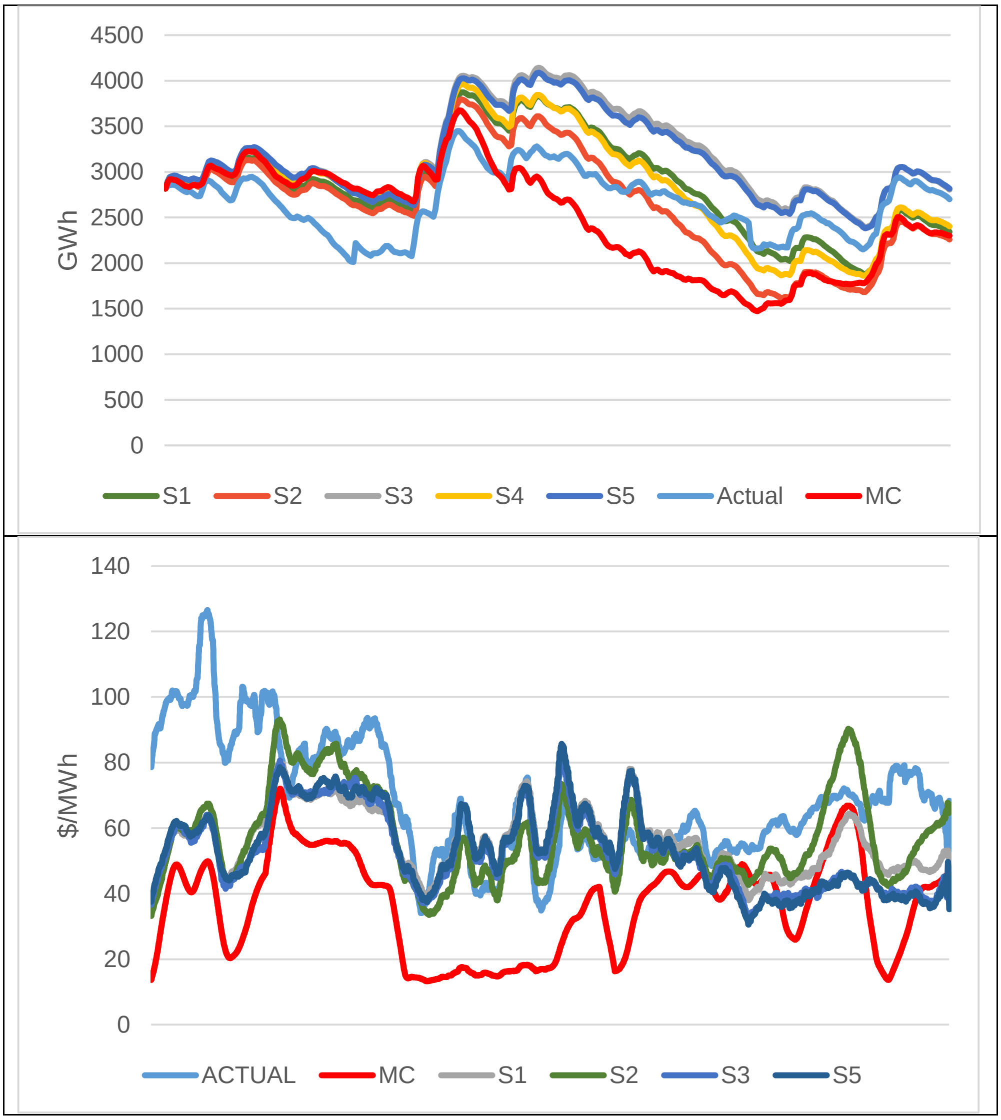


*Figure A 6: 2015 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

## A.7 Dynamic simulation figures 2016

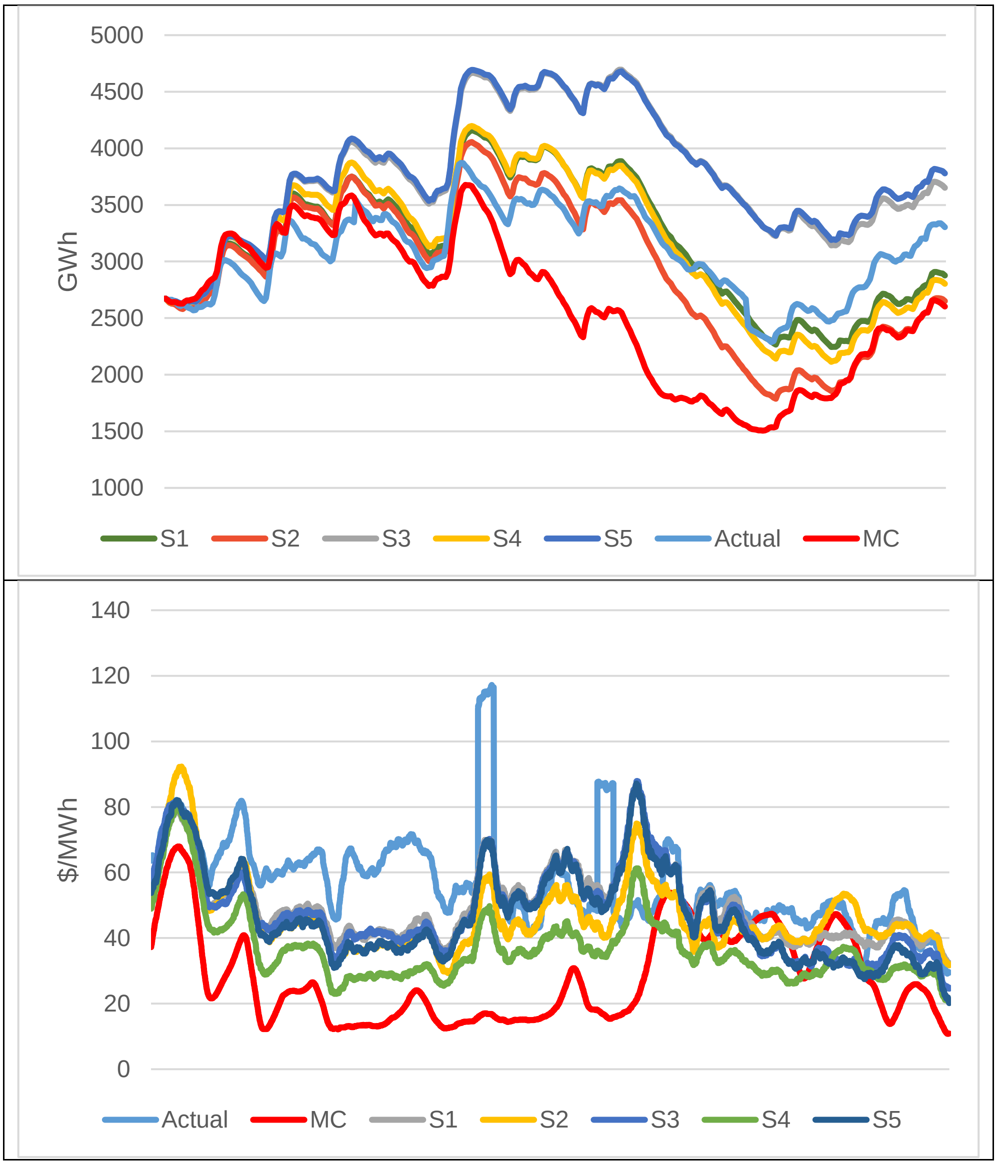


*Figure A 7: 2016 Lake levels (top panel) and average 7 day actual and simulated prices for all seeds.*

# Appendix B. Marginal Costs

Plant and network data are taken from Young et al (2011) except for the thermal plants. Coal prices vary between $4-$5/GJ over the time period (Covec, 2013). We use a constant cost throughout the simulation of $4.1/GJ. For the key thermal plants we calculate the fuel marginal costs using the following heat rates (Denne, 2017). Most of the time the carbon price was zero so we haven't adjusted fuel costs by including a carbon price.

*Table B1: Heat rates for selected thermal plants.*

| | |
|---|---|
| Huntly unit 5 | 7700 |
| Taranaki Combine Cycle | 7700 |
| McKee | 10500 |
| Southdown | 8250 |
| Stratford | 10600 |
| Otahuhu CCGT | 7700 |
| Huntly 1-4 | 10500 |

We calculate the marginal costs of the gas plants using MIBE data reproduced below for each year. The actual fuel costs for each firm are not publicly available but it is known that the firms have long term contracts with prices likely to be lower than the commercial rates quoted here.

*Table B2: Gas prices (MIBE, 2018).*

| Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| Gas $/GJ | 6.91 | 7.16 | 7.04 | 6.61 | 6.62 | 6.25 | 5.29 | 5.18 |