How Does Market Power Affect the Impact of Large Scale Wind Investment in 'Energy Only' Wholesale Electricity Markets?

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The rise of wind and solar in electricity networks has raised concerns about the reliability of supply in, and the design of, electricity markets with large amounts of intermittent generation. Two well understood facts in the literature are: Firstly, increasing the penetration of intermittent generation requires an increase in peaking generation to ensure security of supply during periods where the resource is unavailable. Secondly, increasing wind capacity leads to greater price and dispatch volatility due to the 'Merit Order effect', intermittents dispatch first when available pushing down price relative to periods whens they are not.

These issues raise concerns in 'energy only' electricity markets where firms do not receive side payments for available capacity outside of the revenue they generate on the spot market. In such a market it is unclear whether increasing intermittent penetration will provide a sufficiently large market incentive for firms to invest in the peaking capacity necessary to gurantee security of supply - particularly if regulators are reluctant to see significiant outage hours with high price spikes. In such a scenario returns for peakers will depend on the degree to which firms are able to exercise market power; For peaking plants to make a return on their investments they need sufficient market power to push prices above their short run marginal costs during periods of peak demand. Thus to assess security of supply under intermittent investment it is crucial to combine aspects of a model with capacity investment with one in which firms can exercise market power.

This paper examines the interaction between capacity investment, wind penetration and market power by firstly, using a least-cost generation expansion model to simulate capacity investment with increasing amounts of wind generation, and then secondly using a computer agent-based model to predict electricity prices in the presence of market power. We find the degree to which firms are able to exercise market power depends critically on the level of total installed capacity relative to peak demand. For our preferred long run generation scenario we show market power increases as wind penetration increases and prices overall increase. The market power in turn leads to inefficient dispatch, which is exacerbated, with large amounts of wind generation.

Our setting, the New Zealand Electricity Market (NZEM) provides an excellent laboratory for studying the effects of wind integration for several reasons. Firstly it is one of the purest examples of an 'energy only' electricity market, there is no formal price cap and firms receive no capacity payments. Secondly New Zealand has highly economic wind resource which unlike many countries is not subsidsed. Thirdly the market has a small number of firms and market power is known to be an issue. And finally the NZEM is relatively small hand has no interconnection to other markets which enables each plant in the market to be modelled at high resolution.

Methods

To simulate capacity investment we used the NZ Electricity Authority (EA)'s Generation Expansion Model (GEM) to generate a number of capacity investment scenarios for the year 2025 with varying amounts of intermittent wind generation (EA, 2010). GEM takes as inputs forecast demand and the operating and investment costs of new and existing generation and transmission throughout the country. It then solves assuming competitive dispatch for the generation and transmission mix that minimizes system cost, including capital, operating, and maintenance costs, over the horizon of the model.

Then to model realistic high frequency market dispatch and prices under market power we use SWEM, a computer agent based model developed by Young et. al. (2014). In SWEM, computer agents bid into the market with a portfolio of generation assets. Profits are computed using a simplified 19-node dispatch model of the NZEM These profits are fed into a Modified Erev-Roth computer-learning algorithm (Nicolaisen et. al., 2001). Each iteration, agents update their strategies, construct new bids and the process is repeated until prices converge. Half-hourly wind levels are obtained from National Institute of Water and Atmosphere (NIWA) simulated data. Demand is assumed inelastic and constructed by projecting forward current demand patterns using forecasts from the Statement of Opportunity (EA, 2010), which is also used to model expected future transmission upgrades.

Scenarios are constructed with different amounts of installed wind capacity whilst holding constant the ratio of the 'effective installed capacity' (where wind is discounted by its capacity factor) to peak demand. Firstly we run the long run GEM to determine the capacity mix for each wind penetration scenario. Then we

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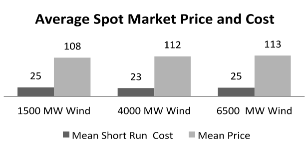
simulate strategic spot market bidding behaviour in the agent-based model SWEM to model dispatch and wholesale prices for each of our wind capacity scenarios.

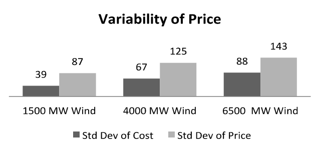
Results

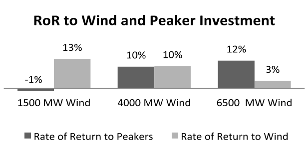
There are three factors which drive trends in average prices as wind penetration increases. Firstly there is the previously described 'Merit Order' effect. Secondly there is an 'Investment Response' effect; as wind penetration increases, the expected capacity factors for other generation in the market falls, so there will be a substitution towards plants with relatively lower capital costs and higher marginal costs. Thirdly there is a 'Market power' effect, as wind capacity increases, during low wind periods supply is tighter relative to demand which enables peakers to exercise more market power pushing prices up.

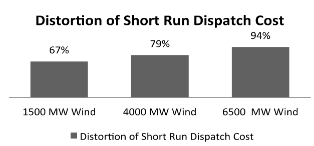
In out simulations we find that as wind penetration increases the merit order and substitution effects almost balance, the average marginal cost of dispatch is flat as wind penetration increases across our preferred scenarios. However the 'market power' effect is significant as the degree to which firms price above marginal cost increases dramatically. Our results support Twomey and Neuhoff's (2010) theoretical result that with market power thermal plants are able to exercise market power more than the intermittent wind generators. Increasing wind penetration leads to increasing price variance; both more periods where there is a zero equilibrium price of electricity and more periods when price is above the marginal cost of a peaking plant.

As the wind penetration increase, we predictably find the rate of return for wind generators falls, however counterintuitively the rate of returns to peakers increases. In our model when wind penetration is around 4000MW (31% of built capacity) both wind and peakers make sufficient returns to incentivse investment. Below this level of penetration there is inadequate returns to incentivise building new peaking capacity, above it there are inadequate returns to incentivise further wind investment.









Although market power enables peakers to make a return on their capital costs, it also leads to a loss of efficiency in our model. Firms have a systematic incentive to withhold capacity to push prices up and there is an asymettric asset allocation among firms. This leads to some low cost generation being withheld and high cost generation dispatching out of merit order. This leads to a loss of efficiency by distorting dispatch from its marginal cost optimal. The loss of efficiency is significant and increases as wind penetration increases. This also leads to increased greenhouse gas emissions compared to competitive dispatch.

Conclusion

To conclude, our results suggest that energy only markets can work with large scale wind penetration. In our simulations there is a 'sweet spot' where both wind and peakers make sufficent returns to invest in an energy only market. However this market would be characterised by highly volatile prices, significant market power and inefficient dispatch.

It is unclear if these are desirable features for electricity markets, some have argued that this implies markets need redesigining. For example (Hall, 2014) quotes "… capacity remuneration mechanisms [are] 'unavoidable' in countries with large shares of renewables with zero marginal costs, such as Germany, said Paul Giesbertz, head of infrastructure and market policies at Statkraft Markets … [because] … with regular high prices in some hours, it was unrealistic to think the public would accept a 'structural appearance of scarcity". Our results suggest that increasing market power seen in our simulations alongside increasing ineffeciciency of dispatch will exacerbate such concerns.

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