The Spatial Analysis of Wind Generation on Nodal Prices in New Zealand

Le Wen and Basil Sharp
Energy Centre, Department of Economics, The University of Auckland, New Zealand
Corresponding author (E-mail): l.wen@auckland.ac.nz

JEL Classification: Q41 Q42 C21

Keywords: spatial analysis, wind generation, nodal price, intermittency, merit order effects

Abstract

The New Zealand government aims to lift the share of electricity generated by renewable resources from 80% to 90% by 2025. Due to the limited potential share from hydro power, wind power could contribute up to 20% towards the achievement of the government's goal. The study uses panel data models to estimate the impact of wind generation on nodal price. In particular, spatial Durban (SDM) are used to investigate spatial and seasonal effects. The direct effects of a marginal increase of 100 MW in wind generation at node *i* are associated with a reduction in the price at node *i* of $4.9 per MWh during the winter months and $20 per MWh during the summer months. The indirect effects of a 100 MW increase in wind generation at neighbouring nodes are associated with a price drop of $27.3 in winter and $95.7 per MWh in summer. Point estimates of the total effect of a 100 MWh increase in wind generation on nodal price are a reduction of $86.4/MWh in spring, $116/MWh in summer, $106.9/MWh in autumn, and $32.2/MWh in winter, and these effects are statistically significant. While increased wind generation reduces nodal price, it also increases the variance in nodal price.

1. Introduction

The expansion of wind generation in New Zealand potentially provides an important contribution to achieving the goal of having 90% of electricity generated from renewable resources by the year 2025. Due to the limited expansion of hydro capacity expected in the future, as much as 20% of the total may need to be generated by wind if this target is to be achieved.

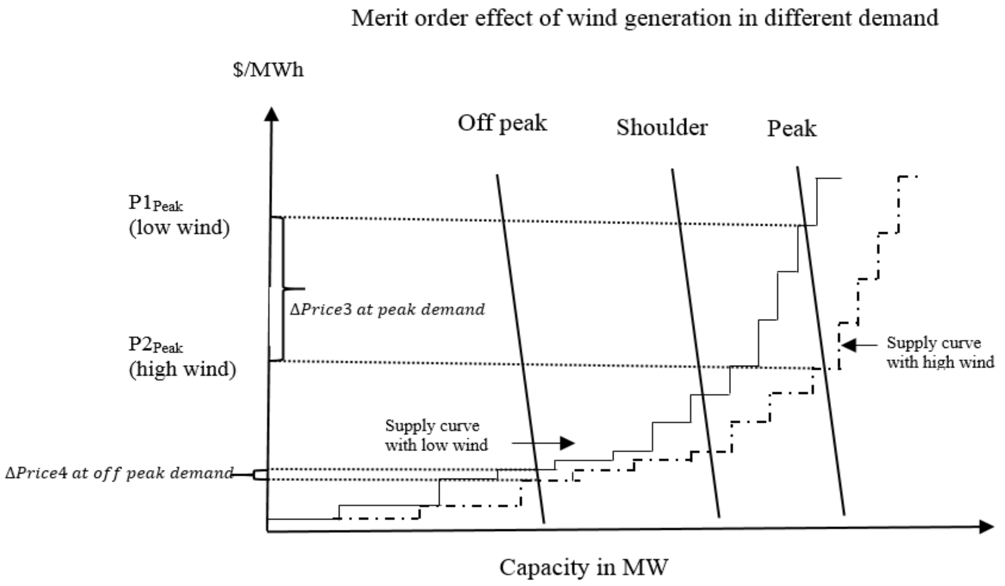
Understanding the behaviour of nodal prices is crucially important for the valuation and risk management of real assets and financial claims (Escribano et al., 2011). The non-storability of electricity, the characteristics of demand and supply and the structure of the market and the market power of the generators all contribute to the observed high volatility of electricity prices (Escribano et al., 2011).

Electricity generation in New Zealand is hydro-dominated, with around 60% of electricity generated by hydro power. New Zealand lacks significant capacity for water storage to provide reliable hydro generation. The total capacity of the hydro lakes in New Zealand is about 3.6 TWh, which can only meet about 5 weeks of winter demand (van Campen et al., 2011). This causes the New Zealand electricity system to be vulnerable to periods of dry weather. Average prices are less stable in markets that are dominated by hydro power. Wolak (1997) found instability of mean prices in the electricity markets of both NordPool and New Zealand.

In addition, hydro reservoirs play a role in the indirect storage of electricity, therefore in these markets we would expect an increased amount of inter-temporal substitution between inputs compared to markets with a higher proportion of electricity generated from non-storable sources. In markets with no inter-temporal substitution we should be able to observe a higher degree of mean-reversion since generators cannot use inventories to smooth out shocks, and the degree of mean-reversion in electricity prices is mainly driven by the mean-reversion in demand or in temperature (Escribano, et al., 2011; Tipping et al., 2004).

According to bids based on short-run marginal costs (SRMC) which compose fuel cost, operation and the maintenance cost of generation technologies, the system operator ranks the supply merit order curve. When more low-cost wind capacity is added, this shifts the merit order curve to the right and pushes out the most expensive generators. This results in the reduction of the wholesale electricity price at a given demand, as illustrated in Figure 1. This effect is called the merit-order effect. The extent of the merit-order effect depends on the steepness of both demand and supply curves. During peak demand, after most of cheaper technologies have been used, the demand curve intersects at the steep part of the supply curve. Consequently, wind generation has a stronger impact on reducing price. Figure 1 illustrates that the merit-order effect is larger in peak demand conditions than in other circumstances. To the contrary, the merit-order effect is smallest in off peak demand conditions. Both Nicholson et al. (2010) and Pöyry (2010) found that the merit order effect is stronger during the day than in the night. The strength of the impact depends on the generation mix and how much flexible conventional capacity there is available at the time.

Figure 1. The impact of wind generation on nodal prices in different segments of electricity demand



Source: own illustration

The addition of wind into existing power supply has been shown to reduce the price of electricity in Germany (Ketterer, 2014; Sensfuß et al., 2008), Spain (de Miera et al., 2008) and Denmark (Jónsson et al., 2010; Munksgaard & Morthorst, 2008). However, policies in these countries directly support renewable energy sources. In a recent review of support schemes[1] in Europe, CEER found that on average 12.6% of the gross electricity produced received RES support in 2012. Denmark had the highest share of electricity produced receiving RES support at 55.9%, followed by Spain at 30% and Germany at 18.2%. In 2013 the weighted average support ranged from 10.56€/MWh to 194.51€/MWh with a weighted average across 21 countries of 110.65€/MWh (CEER, 2015). Furthermore, the majority of countries give priority to renewable energy plants in terms of network access and dispatching. In contrast, the electricity market in New Zealand is open and supply technologies can opt to bid into each 30 minute trading period. When the market closes, the system operator dispatches supply at least cost. As no subsidies are offered in New Zealand for the promotion of renewable resources, this provides an ideal opportunity to examine the effect of wind power on wholesale price.

[1] Support instruments for promoting RES deployment are feed-in tariff and feed-in premium for Denmark and Germany, and feed-in tariff in Spain. More detail can refer to https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/4154396/33476CB022773277E053C92FA8C0B7A8.pdf

Further evidence from the U.S. (Woo et al., 2011) and Germany (Ketterer, 2014) shows that the integration of wind into the existing power supply reduces the price level but increases price volatility. The trade-off between lower nodal price and price variance implies that balancing, using hydro and fossil fuels, will be required with the expansion of wind generation capacity.

The New Zealand electricity market has been the subject of study in a number of academic papers. Young et al. (2014) developed the SWEM model by using a modified version of the Roth and Erev algorithm. They showed that a simplified 19 node model can mimic short-run electricity prices given inputs such as fuel costs, network data and demand. McRae and Wolak (2014) employed the framework in Wolak (2007) and data on half-hourly offer curves, prices, and quantities from the New Zealand wholesale electricity market over the period January 1 2001 to June 30 2007 in order to characterize the way in which the four large suppliers in this imperfectly competitive industry exercise unilateral market power. The empirical results demonstrated that although prices in a multi-unit auction wholesale electricity market depend on supply and demand conditions, the actual supply depends on the offer curves submitted by market participants to the wholesale market, which determine short-term wholesale prices. Tipping et al. (2004) proposed a top-down NZEM spot prices model, incorporating an exponential function of the reservoir storage levels (RSL) into a time series model. National storage level is very limited in New Zealand, making NZEM very sensitive to reservoir inflows. This results in the level and volatility of price fluctuation, being dependent on the amount of water in the reservoirs. They argued that this measure implicitly includes the expected annual average patterns of generation and inflows.

The Wolak report examined the extent to which the main suppliers of electricity exercise unilateral market power in the NZEM (Wolak, 2009). In his report, Professor Wolak makes a distinction between the ability and the incentive to influence price. The inverse elasticity of residual demand (net demand facing an individual supplier when the supply of all competing suppliers has been accounted for) is used to measure this ability. The more inelastic the demand curve, the larger the market power of the supplier. The incentive to influence price depends on the net position of the seller in the wholesale market. The more a seller is committed to selling under long-term contracts (fixed price forward-market obligations), the less gain there is from an increase in the wholesale market price. A supplier who is over-contracted will be a net buyer in the wholesale market and will have an incentive to reduce price (von der Fehr, 2009).

To the best of our knowledge, none of the published studies on the subject have examined the relationship among wind generation, price and price variance in the New Zealand electricity market. In addition, to date, there are no studies which have applied spatial models to research on nodal price. Inspired by the first law of geography: "everything is related to everything else, but near things are more related than distant things" (Tobler, 1970), we use a spatial model to examine the effects of wind power on nodal prices. We hypothesize that the nodal price is influenced, not only by factors at the grid injection point, but also by factors at the neighbouring nodes.

Spatial models have been extensively applied to urban and regional science studies, such as, knowledge and innovation (Anselin, Varga, & Acs, 1997; Boschma, 2005; Carlino, Chatterjee, & Hunt, 2007), cities and clustering (Duranton, 2007; Ellison, Glaeser, & Kerr, 2010), and labour and land markets (Faggian & McCann, 2009; Mellander, Florida, & Stolarick, 2011). The issue of local geographic spillovers between nodal price and wind generation is our particular area of interest, especially when studying the New Zealand electricity market, which is characterized by nodal connections and geographic spread.

Data used in this study are taken from the New Zealand Electricity Authority's Centralised Dataset (CDS), which provides details of actual generation, pricing, and demand data. The sample is restricted to a balanced panel for 2012. New Zealand electricity generation has high reliance on hydro generation which is vulnerable to dry years. The specific weather conditions in 2012 provide us with a good background with which to analyse the impact of wind power on nodal prices and how to balance the system in both dry and wet seasons.

Following the method used by Woo et al. (2011), we also estimate the effect of a 10% increase in wind generation installed capacity on price and price variance. We find that increasing the wind capacity tends to reduce nodal price, but also tends to increase the variance in this area. The results are consistent with those of Woo et al. (2011) who applied the method of maximum likelihood to study the four ERCOT Zonal market-price, and Ketterer (2014), who examined the effect of wind generation on the level and the volatility of the electricity price in Germany based on a GARCH model.

New Zealand's electricity market would face bigger challenges when integrating intermittent wind generated power into the power system than was the case with the Nord pool electricity market[2] due to its special geographical features where there are no interconnections available for exporting the surplus to, or importing to meet a shortage from, the electricity networks of other nations. This may exacerbate the increase in the price volatility when adding intermittent wind into an electricity system.

A number of studies have clearly demonstrated the impact of increased wind penetration on electricity market spot prices. However, robust econometric evidence is limited. By establishing the geographical location of wind farms, we estimate the spatial impact of wind generated electricity at neighbouring nodes, once again controlling for other sources of electricity.

This paper is the first empirical application of spatial econometric methods to examine the impacts of wind generation on nodal price in New Zealand, while also controlling for other competing sources. In particular, the spatial panel data model accounts for cross-sectional dependence and controls for heterogeneity. In 2012, the hydro storage level was lower than that of the last 20 years' average, except during the late spring. The particular feature in 2012, that it was dry in summer, autumn and winter, and wet in spring, provides us an ideal situation to analyse the integration of hydro power, wind, and other forms of generation. The seasonal effects show that price reduction varies across seasons, ranging from 2.25% in winter to 11.44% in spring. The reduction in nodal price is associated with increased nodal price variance except in spring. Even with a large price reduction in spring after adding 10% wind capacity, the variance in nodal price increase mildly compared to the increase in the dry seasons. In spring, electricity was exported from the South Island to the North Island via the HVDC link. The amount of electricity was mostly generated by hydro power in the South Island which balanced the shortage of electricity in the North Island. In this situation, the price variation from wind would have been reduced by the generation of hydro power. The findings imply that price variation in a wind-hydro system is smaller than in a wind-thermal-hydro system.

The paper is structured as follows. Section 2 describes the New Zealand Electricity Market context. Section 3 discusses the data and the statistical evidence. Sections 4 and 5 describe the methodology and the empirical results. Section 6 concludes this paper.

[2] In the Nordic electricity market, the surplus or shortage of electricity can be exported or imported within Nord pool electricity market (Denmark, Finland, Sweden, Norway, Estonia and Lithuania).

2. The New Zealand Electricity Market context for wind generation

Beginning in 1986 New Zealand embarked on a series of industrial reforms that transformed the sector from a state-owned monopoly into a sector founded on the market, with no subsidies, operating within a framework of light handed regulation. Transpower, originally a subsidiary of the Electricity Corporation, was separated in 1996 to become the owner of the national grid and the system operator. That year the wholesale electricity market began operating with nodal pricing. As a replacement of the Electricity Commission, the Electricity Authority, which was established in 2010, now oversees the New Zealand electricity market (NZEM).

Since 2004, the wholesale electricity market has operated a compulsory pool market where all generated and consumed electricity is traded. Bilateral and other hedge arrangements are still available but function as separate financial contacts. Each generator offers generation to the Independent System Operator (ISO) in the forms of offer stacks. Bids (purchaser/demand) and offers (generator/supply) are uploaded into the wholesale information and trading system (WITS) by electricity market participants. Transpower, in its role as the Independent System Operator (ISO), ranks offers in order of price and selects the lowest-cost combination that satisfies demand. Prices on the spot markets are calculated every half hour using scheduling pricing and dispatch (SPD) software and vary depending on supply and demand, and the location of an area on the national grid.

There are 11743 KM of high-voltage transmission lines in New Zealand. The transmission grid contains about 250 nodes and over 450 links. Currently, both electricity generation and retail are open markets, but transmission and distribution are natural monopolies. Five major generators (Contact, Trustpower, Genesis Energy, Meridian Energy and Mighty River Power) operate 179 out of 200 power stations and produce 95% of New Zealand’s electricity. Each generator has its own retailer business. With no subsidies promoting renewable resources, New Zealand’s deregulated market provides an ideal opportunity to examine the effect of wind power on nodal prices.

Annual average electricity demand is continuing its flat trend with an amount varying between 40,000 GWh and 42,000 GWh. However, demand varies from moment to moment with daily, weekly and seasonal patterns. Two daily peaks reflect the morning peak driven by households waking up and heating their houses and the evening peak driven by cooking the evening meal.

Commercial operations and manufacturing are active during the week rather than at the weekend. There is high demand for electricity during the winter for space heating. In the South Island, electricity demand increases during the summer because of the increase in farm irrigation in this region (EMR, 2012). Population, gross domestic product, and other factors also influence demand.

Currently, the total installed electricity capacity in New Zealand is approximately 10GW. In 2015, approximately 81% of electricity was generated by renewables (MBIE, 2016). As a hydro-dominated electricity system, the generation share changes annually according to the amount of rainfall. Hydro generation, as a dominant form of installed electricity generation capacity, accounted for 57% of electricity generation during the 2011-2014 period. During this period the electricity percentage generated from thermal sources was 21%, geothermal 15%, wind 5% and cogeneration 3% (MBIE, 2015).

Compared to Norway, a country that also has a hydro-dominated electricity system, with 98% of its electricity being generated by hydro and accounting for 50% of the total Nordic power generation, New Zealand's electricity market would face a bigger challenge when integrating the intermittent wind into its power system due to its special geographical features and relatively limited storage capacity. Electricity is supplied and consumed within the country, i.e., no electricity is imported or exported. The high reliance on hydro generation and the comparatively small amounts of water storage make New Zealand's electricity system vulnerable to dry years. A hydro generator would like to keep water for later use due to the increasing opportunity cost of water[3] in dry years. Spot prices can be very volatile on the mid-term scale because of uncertainty in drought years. While the surplus or shortage of electricity in Norway can be exported or imported within the Nord pool electricity market (Denmark, Finland, Sweden, Norway, Estonia and Lithuania), the same is not true for New Zealand. The interconnection between Nordic countries assures the necessary back up supply of electricity for Norway's electricity system in drought years (Van Campen, 2010).

Thermal generators produce electricity from coal, diesel and gas. Huntly power station, as New Zealand's largest power station with a capacity of 953MW, is comprised of one 403 MW gas-fired high-efficiency Unit 5, two 250 MW Gas/Coal Rankine Units, and one 50.8MW

[3] The opportunity cost of water depends on current water storage levels and expectations regarding the distribution of future water inflows and outflows.

Gas/Diesel Unit 6. These Units are operated as base-load or peak load when hydro power supply is low.

Geothermal energy provides a consistent and reliable supply because it draws on heat stored in the ground and does not depend on weather conditions. New Zealand has an abundant supply of geothermal energy. Total geothermal electricity capacity was 978MW in 2014 and provided 16% of the annual electricity in New Zealand that year. There is another approximately 1,000 MW of geothermal resource that could be tapped for generating electricity. The extent of renewability of a geothermal resource relies on the rate of extraction and heat regeneration rate. Excess extraction can lead to subsidence and depletion. Monitoring to control water and pressure levels is required when using geothermal resources (Malafeh & Sharp, 2015).

The relative contributions from the generation mix from 2011 to 2015 show that geothermal generation is displacing thermal generation over time and continuing to grow. Three thermal plants with a total capacity of 1055 MW closed in 2015. Two Rankine Units with a combined capacity of 500 MW in Huntly are expected to close in 2019. Because thermal generators provide a stable and flexible power supply, thermal closure would increase the potential security of supply risk. Hydro and gas peaking provide flexibility..

The fraction of power generated from wind is growing in New Zealand. As can be seen in Figure 2, the installed capacity experienced little growth over the 1993-2003 period, and there was a relatively large growth in 2011, reaching 623 MW; capacity stayed at 623 MW until 2014 when a further 66 MW was added. In 2015, the combined installed capacity reached 690 MW and electricity generated by wind accounted for about 6.4% or 2,333 GWh. Currently, there are 19 wind farms. The majority of the existing wind farms are located in the Waikato, the Manawatu, Wellington and Southland. Northland and the west coast of the South Island, the Waikato, South Taraniki, Hawkes Bay, Canterbury, Otago and Southland are the future wind growth areas.

The following section reports on wind speed at different sites across New Zealand. The evidence will provide important information for developers of wind farms when they select wind sites for investment. In addition, this evidence is examined in the model shown in Section 5.

A five-year MM5-based series with intervals of 10 minutes of synthetic wind data (SWD) at a hub height of 85m is used in this study. Data collected at a certain hub height provides a highly accurate assessment of wind power compared to data collected at a weather station at 10m height (Suomalainen et al., 2015). This synthetic wind time series covers 15 sites corresponding to either, existing, proposed, or potential wind farms, with records time-stamped to preserve realistic meteorological inter-area correlations and to allow modelling of the impact of specific meteorological events. NIWA with the NZ MetService as a sub-contractor, contracted by the Electricity Commission, has produced a multi-year wind SWD dataset for use in modelling the electricity system. The wind archive data has been inferred by running the local area model MM5[4]. Figure 3 (a) presents the regions within which these 15 sites were located. Results show that eleven sites reproduced the high frequency fluctuations well and 4 sites (CNI2, MWT1, CTY1, and STH1) reasonably well.

The wind speed[5] map in Figure 3 (b) indicates stronger wind at the bottom of the North Island and the South Island. Corresponding to the wind sites in Figure 3 (a), both MWT and STH are good sites for the installation of wind farms, holding other factors equal.

After excluding nodes that contribute less than 1% of annual demand, we used 11 of the 19 nodes, which is simplified version of New Zealand's 244 node network (Browne et al. 2012).In 2012, more than 90% of the total demand was supplied from these nodes. The map of the 11 nodes (blue colour) is depicted in Figure 3 (c). The locations for these nodes are dispersed across the country. Correspondingly, types and locations of generation plants are reported in Table 1. Each node has one or two types of generating plant. As in Browne et al. (2014), we have matched our nodes of interest with corresponding wind sites (Figure 3, (a)). Four wind sites are located in the North Island: MWT1, CKS1, NTH1 and CNI2; there are two wind sites in the South Island: STH2 and STH3 (Browne et al., 2014).

Wind is free, clean and abundant in New Zealand. Large areas exposed to high wind speeds provide great potential for wind generated power in New Zealand. The capacity factor[6] of wind

[4] MM5 was developed at Pennsylvania State University and the National Center for Atmospheric Research as a community based model.
[5] A typical wind turbine power is assumed to be zero before cut-in speed at which the turbine first starts to rotate and generate power, then cubic of speed between cut-in speed (around 3.5 m/s) and rated output speed (12-14m/s), and then constant until cut-out speed (usually 25m/s) at which a braking system is employed to bring the rotor to a standstill because of a risk of damaging rotor when power drops to zero (Whiten et al., 2013).
[6] Capacity factor is a measure of the amount of electricity actually generated relative to the amount that would have been produced if the generator had been running at its full output over the same period.

farms is the highest in the world with an average of 40 per cent. Statistics for wind speed at the nodes, reported in Table 3, show the higher the wind speed, the larger the standard deviation. This implies that wind generation is most volatile at wind sites with larger than average speeds. Further information is given in Figure 4. MWT1 has the highest average wind speed but also with the highest volatility. The wind speed is low at CNI2 and NTH1, but volatility is also low. Developers of wind farms should note that if they select a site with higher than average wind speed, appropriate instruments for risk management will be required to deal with wind volatility. At sites where the wind speed is low; but quite consistent, wind generation will be stable and reliable.

Table 4 illustrates the significantly positive correlation between wind speeds at different wind sites in New Zealand. The high correlation between different winds sites indicates that a shortage of supply at one site cannot be substituted for supply at another site because their wind speed is likely to be similar.

Nevertheless, since the correlation between sites is not perfect, having wind sites dispersed throughout the country will reduce the variability of wind generated power for the grid as a whole and will also reduce the impact of weather. A nationwide balanced wind network will ensure the reliability of wind contribution to electricity production and reduce price volatility (Wind Energy 2030).

The New Zealand Government aims to lift the share of electricity generated from renewable resources from 80% to 90% by 2025. Due to the limited expansion of hydro capacity expected in the future, wind may need to contribute as much as 20% of the total if this target is to be achieved. According to New Zealand Wind Energy Association (NZWEA), the supply of wind power will continue to increase. An additional 15 wind farm projects have been consented to, with a total capacity of 2725.5 MW. With this trend, wind generated electricity will reach at least 3,500 MW capacity by 2030 (Wind Energy 2030).

The long run marginal cost (LRMC)[7] of wind power is decreasing with NZ's large, mature and growing wind industry. The zero cost of fuel for wind and the increasing cost for fossil fuels provides wind with a comparative advantage in the future. The incentive for a developer to

[7] LRMC covers capital and variable costs, and varies over time with changes in equipment, fuel costs and new technology, etc. Developers are expected electricity prices need to be at or above LRMC to build new plant.

invest in wind farms depends on whether the spot price is expected to be larger than LRMC. The spot price is adjusted accordingly when a new plant starts to operate. Based on the SOO2008[8] and DBN2016[9] reports, the ongoing LRMC reduction for wind generation allows wind generation to be more competitive than other generation technologies in the future.

As discussed previously, due to NZ's special geographical features, the New Zealand electricity market will face greater challenges than the Nord pool electricity market does when adding intermittent wind power into power system. We hypothesize that the impact of wind generation on price is larger in dry periods than in wet periods because more backup thermal generation is required and fuel price is uncertain and varies over time. According to the SOO2008 report, the capacity credit[10] of wind in the hydro dominated system of New Zealand ranges from 32% for a low wind penetration level (5%) to 23% for a high wind penetration level (20%). The higher capacity cost and reserve cost from the increased wind penetration leads to a smaller wind capacity credit. In Germany (Nicolosi & Fürsch, 2009) found that increasing wind penetration reduces the relative capacity credit. In 2003, wind capacity was 14.5 MW with a capacity credit of 7-9%, meaning that 1-1.3 GW of conventional capacities can be substituted.

8 2008 Statement of Opportunities.
9 Deloitte, Bloomberg and NZWEA. Refer to http://www.windenergy.org.nz/store/doc/Wind_Energy_2030_Document_Web.pdf
10 The capacity credit is the peak demand less the peak residual demand, expressed as a percentage of the variable renewables installed. It is typically expressed as how much other generation capacity wind can allow to be shut down. For example, if 100MW of wind power plants are installed in a region, and their capacity credit is 30%, then there will be reduction of 30MW in the amount of other plants required, compared to a situation with no wind capacity.

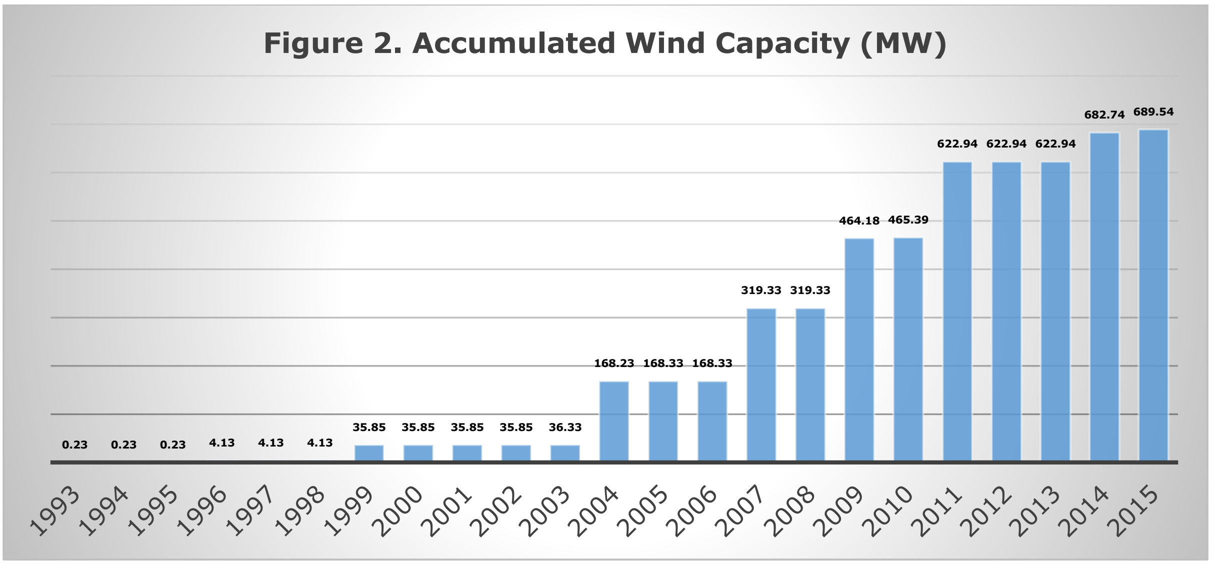
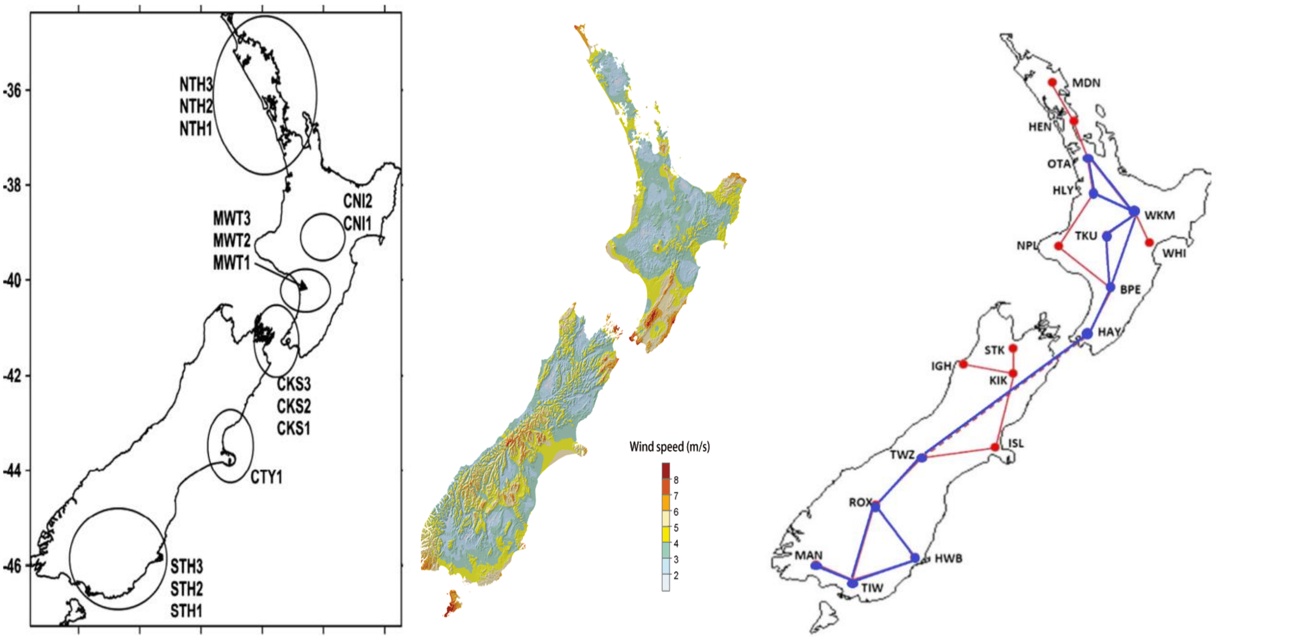


Figure 2. Accumulated Wind Capacity (MW)

Figure 3. Wind sites, Wind speed[11] and Simplified Nodes[12]



a) Wind sites　　a) Wind speed　　c) Simplified Nodes and Nodes in the study (Blue)

[11] Four wind sites in the North Island: MWT1, CKS1, NTH1 and CNI2. Two wind sites in the South Island: STH2 and STH3. Note, MWT for Manawatu and Wanganui, CNI for Central North Island and Hawkes Bay, and NTH Coastal parts of Waikato, Auckland, Coromandel, and Northland. STH is the regional identifier for Southland and Otago, CTY for Canterbury, CKS for Cook Strait.

[12] Geographic map for 11 Nodes (blue colour) in New Zealand: 6 nodes in the North Island (OTA, HLY, WKM, TKU, BPE and HAY) and 5 nodes in the South Island (TWZ, ROX, HWB, TIW, and MAN)

Table 1. Types of plant and X&Y coordinates of the 11 nodes (6 nodes in the North Island and 5 nodes in the South Island)

Index	**Node in the North Island**	**Plant types**	**Y-coordinate Latitude**	**X-coordinate Longitude**
1	BPE – Bunnythorpe	**Wind**	-40.2809	175.6396
2	HAY – Haywards	**Wind**	-41.150278	174.981389
3	HLY – Huntly	**Thermal, Wind**	-37.543889	175.152778
4	OTA – Otahuhu	**Thermal**	-36.9512	174.865383
5	TKU – Tokaanu	**Hydro**	-38.98113	175.768282
6	WKM - Whakamaru	**Geothermal, Hydro**	-38.419633	175.808217
7	TWZ	**Hydro**	-44.25	170.1
8	ROX	**Hydro**	-45.475811	169.322555
9	HWB	**Wind**	-45.854722	170.475
10	TIW	**Wind**	-46.598034	168.364105
11	MAN	**Hydro**	-45.521389	167.277778

Table 2. Matching SWEM Nodes to NIWA Wind Speed Data

North Island		**South Island**	
Node	**Wind Site**	**Node**	**Wind Site**
BPE	**MWT1**	**TWZ**	STH3
HAY	**CKS1**	**ROX**	STH3
HLY	**NTH1**	**HWB**	**STH2**
OTA	NTH1	**TIW**	**STH2**
TKU	CNI2	**MAN**	STH2
WKM	NTH1		

Notes: Four wind sites in the North Island: MWT1, CKS1, NTH1 and CNI2; Two wind sites in the South Island: STH2 and STH3 (Browne et al., 2014)

Table 3. Statistics for Wind Speed

Variable	Observations	Mean	Std.Dev	Min	Max
MWT1	262,662	10.525	5.365	0	43.72
CKS1	262,662	9.099	4.511	0	35.97
NTH1	262,662	8.450	4.034	0	32.73
CNI2	262,662	8.486	4.161	0	28.99
STH2	262,662	9.560	4.998	0	32.78
STH3	262,662	11.414	6.239	0	42.1

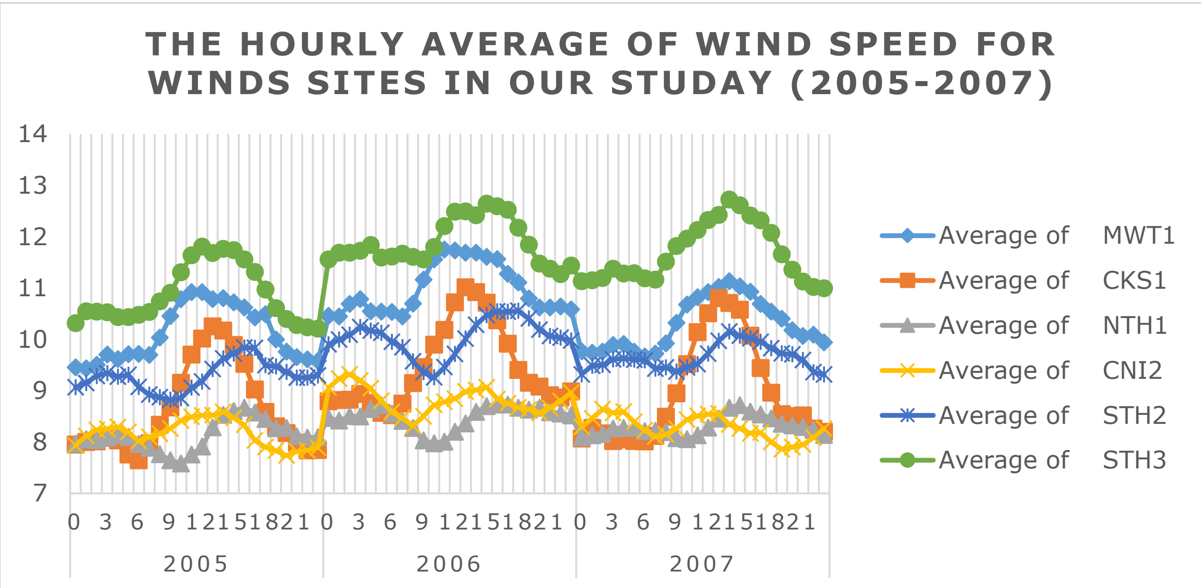
Source: NIWA (Sep 2003 to Aug 2008)

Table 4. Hourly Correlations between Wind Sites in New Zealand

	MWT1	CKS1	NTH1	CNI2	STH2	STH3
MWT1	1.000					
CKS1	0.494***	1.000				
NTH1	0.369***	0.308***	1.000			
CNI2	0.579***	0.273***	0.449***	1.000		
STH2	0.349***	0.280***	0.295***	0.412***	1.000	
STH3	0.435***	0.333***	0.276***	0.377***	0.655***	1.000

Source: NIWA (Sep 2003 to Aug 2008)
*** denotes statistical significance at the 1% level.

Figure 4. Hourly Average of Wind Speed for Wind Sites

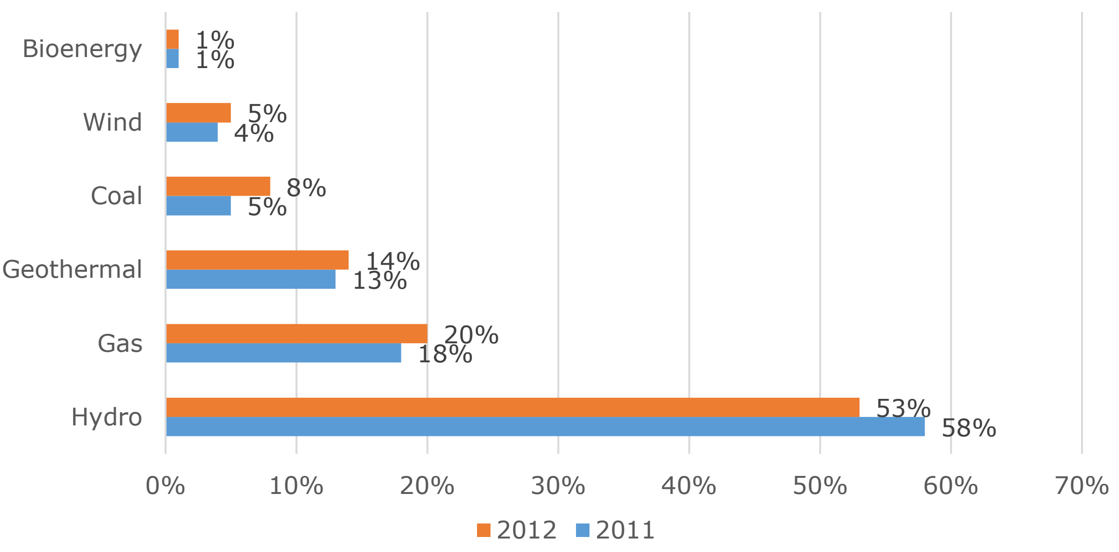


Source: NIWA (Sep 2003 to Aug 2008)

3. Data and Statistical Evidence

Data used in this study are taken from the New Zealand Electricity Authority's Centralised Dataset (CDS), which provides details of actual generation, pricing, and demand data. The sample is restricted to a balanced panel for 2012. There are a number of reasons for the choice of 2012 data. First, 2012 was a dry year. As a hydro-dominated electricity system, in a dry year, the opportunity cost of using water is expected to increase; wholesale prices are expected to rise and thermal plants are expected to increase generation, this will lead to more price spikes in comparison with wet years due to greater uncertainty during periods of drought. We are interested in estimating the effects of wind generation on nodal prices during dry and wet seasons. The findings will provide empirical evidence on how to integrate wind power into the electricity system. Secondly, as discussed previously, there was a minimal increase in installed capacity over 1993-2003. In 2011, there was a relatively large increase in installed capacity, reaching 623 MW; remaining at 623 MW until 2014 when the addition of 66 MW occurred. Thirdly, Figure 5 shows that wind energy accounted for 5% of energy generation in 2012 compared to 4% in 2011. The decrease in hydro generation from 58% in 2011 to 53% in 2012 is associated with an increase in thermal generation from 23% in 2011 to 28% in 2012. Thus, the behaviour of generation mix in 2012 provides an ideal platform with which to analyse the effects of wind on price and price volatility.

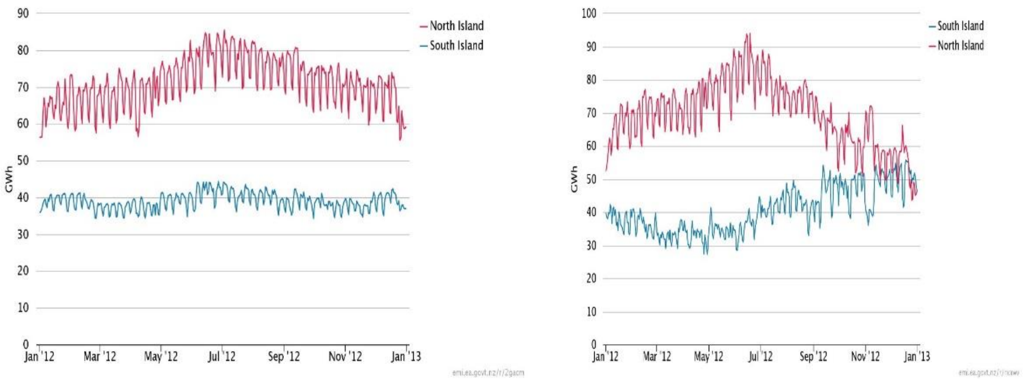
Figure 5. Electricity Generation by Fuel Type for 2011 and 2012
(Source: MBIE 2013: Energy in New Zealand 2013)



In the following sub-sections, detailed information on grid demand, supply, hydro storage level, HVDC transfer, price and thermal generation in 2012 is presented, followed by statistical evidence concerning wind, thermal and price.

3.1 Grid Demand and Supply Trends 2012

Figure 6. Grid Demand and Supply Trends 2012 (daily average)



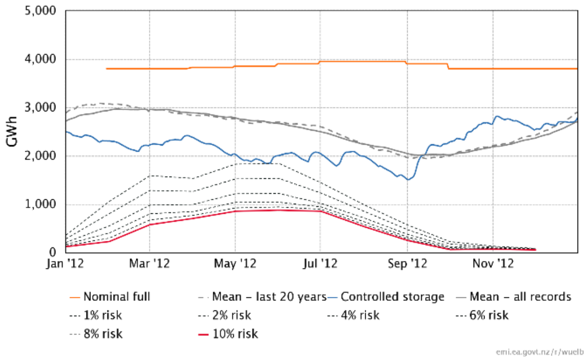
a) Demand b) Supply

Source: Electricity Authority-Electricity Market Information (EA-EMI)

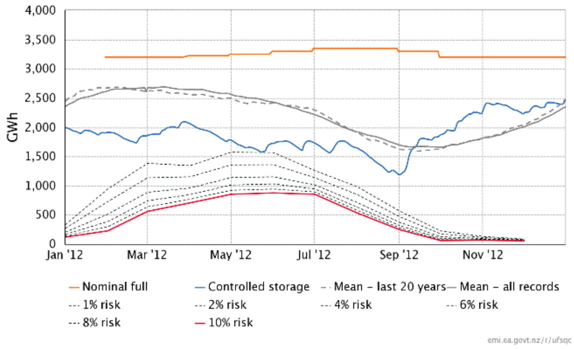
Figure 6 presents grid demand and supply trends in 2012. In general, demand in the North Island was higher than that in the South Island. Demand was high in winter in the North Island, while demand was flat in the South Island. The electricity use for irrigation in summer may have countered the effect of the high use in winter in the South Island. Further information can be revealed from the supply side. Correspondingly, to accommodate demand and lack of hydro generation before September due to low hydro levels in the South Island, a large volume of electricity was generated in the North Island, more in winter than during other seasons thus meeting demand in the North Island; the remainder of the power generated was exported to the South Island. As discussed previously, geothermal generation provides a consistent supply of power, wind generation depends on weather, and thermal power generation covers shortages in hydro generation.

3.2 Hydro Storage

Figure 7. Historical Hydro Risk Curves 2012



a) New Zealand



b) South Island

Source: Electricity Authority-Electricity Market Information (EA-EMI)

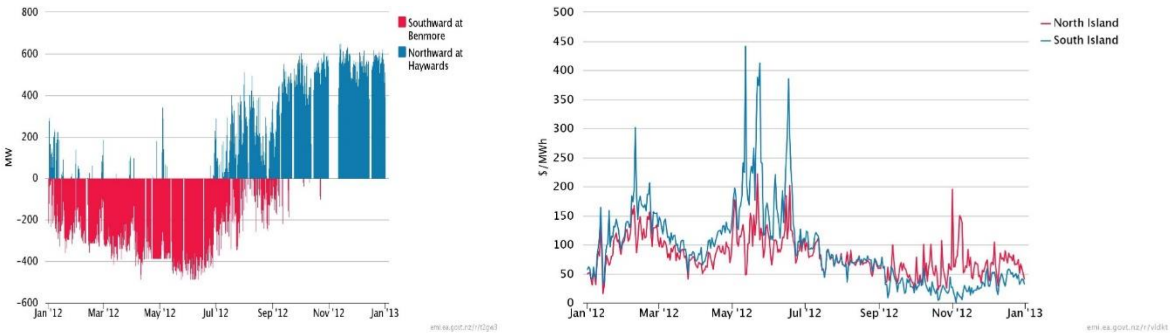
Around 60% of the total amount of electricity in New Zealand is generated by hydroelectric generation. The overall supply risks are indicated by controlled and contingent storage. Generators use controlled storage at any time and contingent storage during defined periods of shortage or risk of shortage. South Island controlled storage represents about 85% of New Zealand's controlled storage capacity.

The above graph shows that controlled storage for the period indicated was lower than the previous 20 years' average level, with the exception of the time during the late spring of 2012. Storage hit a 1% hydro risk curve[13] in May, and continued to fall. It recovered in mid-September when controlled storage was closer to the mean and eventually reached the mean storage point. After this point, storage remained above the mean storage level for the rest of the year. Storage in the North Island is the subtraction storage in New Zealand from the storage in the South Island. The similar patterns in two figures imply that the North Island had stable hydro storage and that the South Island experienced dry seasons before September 2012.

[13] Hydro risk curve is a measure of the probability of forced electricity cuts.

3.3 HVDC Transfer and Nodal Prices

Figure 8. HVDC Transfer between Islands and Nodal Prices



a) HVDC Transfer b) Nodal prices

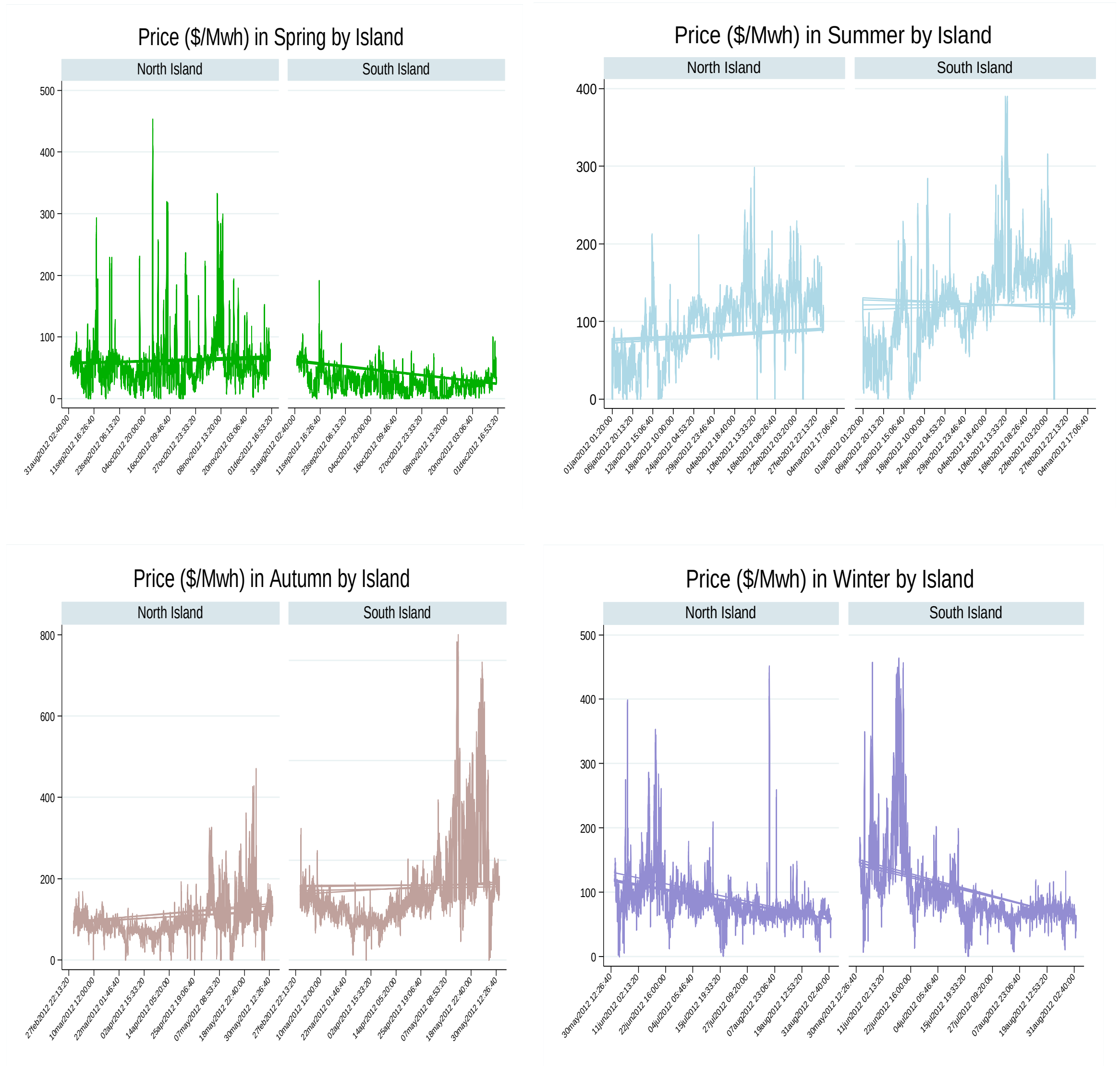
Source: Electricity Authority-Electricity Market Information (EA-EMI)

The electricity surplus of one island is transferred to the other island by a high-voltage direct current (HVDC) link. During dry periods, HVDC provides the South Island consumers with access to the North Island's thermal generation capacity. As can be seen in Figure 8, there was a consistent southwards flow over the HVDC before September 2012. During wet periods, the HVDC transfers surplus South Island hydroelectric power northwards to the North Island. Correspondingly, the nodal price was higher in the South Island than in the North Island before September. This adverse effect on price remained for the rest of the year. In addition, high prices were found in dry periods and low prices in wet periods. The HVDC transfer also reflected the reduction of water available for hydro generation for future use; this was due to the relatively high value of water during dry periods.

The market responded to the shortage of water available for hydro generation in the South Island in a variety of ways and thus avoided the need for extraordinary measures. Customer compensation scheme provisions introduced in April 2011 require that each retailer has a scheme and describes how it will compensate its customers during public conservation periods. This creates an incentive for retailers with generation capacity to continue to generate and supply rather than calling for conservation measures. Generators that enter into hedges also have incentives to continue to generate to cover their hedge positions, although they would not be directly affected by the customer compensation obligations of the energy purchasers holding these hedges.

3.4 Nodal Prices by season and Island

Figure 9. Nodal Prices by Season and Island

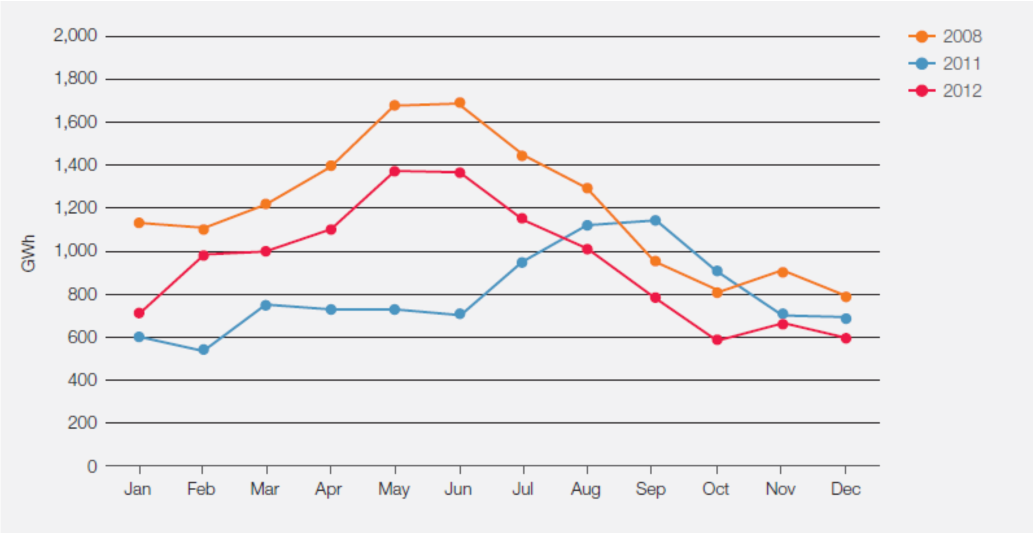


Source: Electricity Authority (EA), Centralised Dataset

Figure 9, illustrates seasonal and spatial variations in nodal prices. In spring, when hydro levels were high in the South Island, the nodal price was lower than the North Island. More price spikes were found in the North Island than in the South Island. Nodal pirces rose during dry periods, and prices were higher in the South Island than in the North Island when HVDC transferred surplus North Island thermal power southwards to the South Island. With the addition of more thermal generation, further price spikes occurred.

3.5 Thermal generation

Figure 10. 2008 (dry year), 2011(wet year) and 2012(dry year)



Source: Electricity Authority. Electricity Market Performance: A Review of 2012.

Both 2008 and 2012 were dry years as opposed to 2011, which was a wet year. The year, 2012 had more thermal generation than 2011. The highest thermal generation occurred in May for both 2008 and 2012 compared to the rest of the months. Low hydro storage levels in the South Island earlier in 2008 and 2012 caused high spot prices because the marginal water value for hydro was increasing and the offer stacks were relatively steep compared to those in a wet year. Thermal generators generated more power in the North Island to gain profit from high spot prices. Since it required only a portion of the total thermal generation to meet power demands for the North Island, the rest of thermally generated power was exported to the South Island.

3.6 Wind generation

Tararua, Te Rere Hau and Te Apiti wind farms are aggregated into one Node, BPE. The Tararua wind farm is New Zealand’s largest wind farm with 264 MW capacity, both in terms of the number of turbines and output. The HLY node has both wind and thermal generation which allows us to analyze the relationships among wind, thermal and prices. The shares of supply from BPE, HAY and HLY are presented in Table 5.

Table 5. Wind generation for Nodes BPE, HAY and HLY

Aggr. node	Type	Plant	Inst. Cap. [MW]	Typ. output [GWh/yr]	Share of supply (Typ.out/Total production 42900 GWh/yr)
BPE	**wind**	Tararua Stage 2	36.3	147	
	wind	Tararua Stage 1	31.7	128	
	wind	Tararua Stage 3	93	375	
	wind	Te Rere Hau	48.5	160	
	wind	Te Apiti	90.75	258	
BPE(Total)			**263.95**	**1068**	**0.025**
HAY	**wind**	West Wind	**143**	**550**	**0.013**
HLY	**wind**	Te Uku	**64.4**	**225**	**0.005**
	thermal		**1453**	**8105**	**0.189**

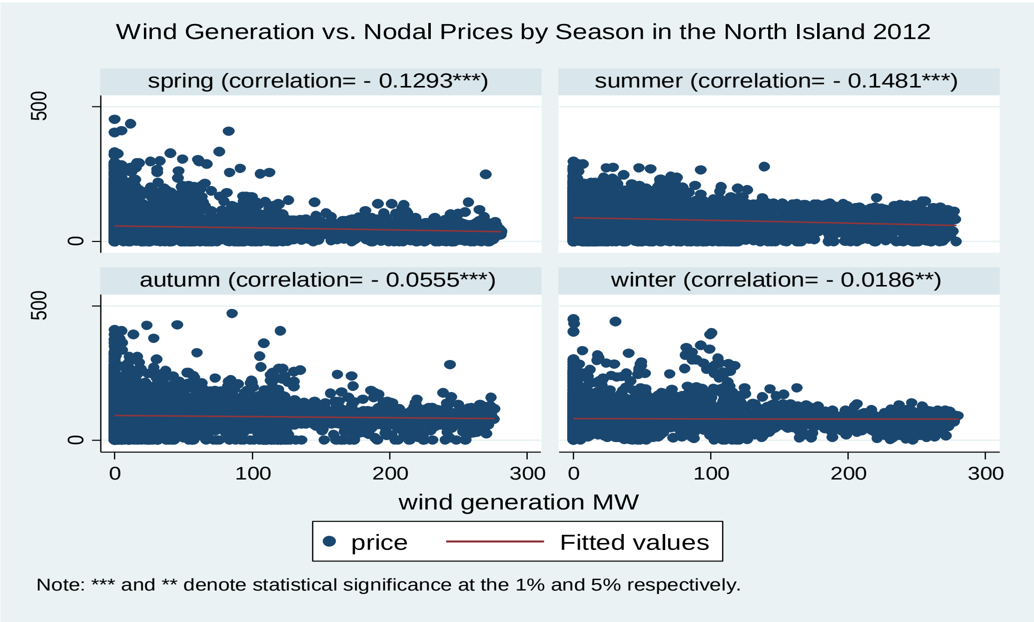
Source: New Zealand Wind Energy Association (NZWEA).http://www.windenergy.org.nz/wind-energy/nz-windfarms

3.7 Negative relationship between spot price and wind generation

This section follows the structural analysis that was adopted by Morthorst (2007) to quantify the impact of wind power on spot price. We hypothesize that high wind generation would lower the nodal prices and that, conversely, low wind generation would lead to higher nodal prices.

Figure 11 shows the scatter plots that demonstrate the seasonal effects of wind generation on nodal prices. They indicate statistically significant negative but weak correlations ($-0.1481<R<-0.0186$) between wind generation and prices. Correlations in autumn and winter were low relative to spring and summer. However, there are other factors which may also influence price such as load, fuel price, and rainfall. The impacts of wind generation on prices will be examined in our spatial models.

Figure 11. Wind generation for Nodes BPE, HAY and HLY



Source: Electricity Authority (EA), Centralised Dataset.

After data cleaning, we found that the average wind generation for BPE and HAY was 114 MWh and 56 MWh, respectively. We selected two specific days; 5 January and 23 October. The graphs in Figures 12 and 13 reflect the relationship between spot pricing and wind generation for BPE and HAY under conditions of both high and low wind generation in an intra-day electricity market.

On the 5 January 2012, there was a high level of wind generation (>114MWh for BPE and >56 MWh for HAY); in general, there is a negative relationship between spot price and wind generation. On this occasion, “noise” existed because there were a few overlaps between curves for the chosen days. This suggests that a high level of wind generation does not always imply a lower spot price when compared to conditions in which there is low wind power production. This result is also consistent with Morthorst’s (2007) findings. Significant statistical uncertainty exists; moreover, factors (e.g. electricity demand), other than wind generation, also influence the spot price.

Similarly, on 23 October 2012, there were low levels of wind generation (<114MWh for BPE and <56 MWh for HAY). On average, the price was higher on that day compared to the price on 5 January.

3.8 Positive relationship between spot prices and load

Figures 14 and 15 present the relationship between spot prices and load for node BPE and HAY. The graphs show that the price level in conditions of low wind generation is higher than the price level during conditions of high wind generation. However, electricity price is not solely determined by wind power generation (Ketterer, 2014). The demand for electricity dominates spot pricing and has the greatest influence on spot pricing when compared to the influences of other factors (Cutler et al., 2011).

In general, we found a positive relationship between load and spot prices. Peak demand occurs in the morning about 8am and about 7pm in the evening, spot prices are high during these periods of peak demand.

3.9 Relationship among spot prices, wind and thermal at HLY

Apart from considering the relationships among wind, load and prices, the thermal generators' behaviour and their generation decision-making in regard to nodal price changes are also explored in this study. The HLY node has both wind and thermal generation which allows us to investigate the relationship between thermal generation and nodal price. However, this exploration has to be undertaken with caution because wind capacity (64.4 MW) is substantially smaller compared to large thermal capacity (1453 MW) which may weaken the role that wind plays on prices at HLY node.

We selected four specific days; 21 and 22 March when wind generation was high and 3 and 4 January, when wind generation was low. Based on the storage level shown in Figure 7, 21 March and 22 March were two autumn days that were drier than 3 and 4 January. In this situation, water value was high and hydro generators kept water for more profitable future use. Nodal prices were high and thermal generators became profitable for despatching more thermal generation to meet both base and peak loads. The graphs in Figure 16 illustrate the relationship among nodal price, thermal and wind generation under conditions of both high and low wind generation in a two intra-day electricity market.

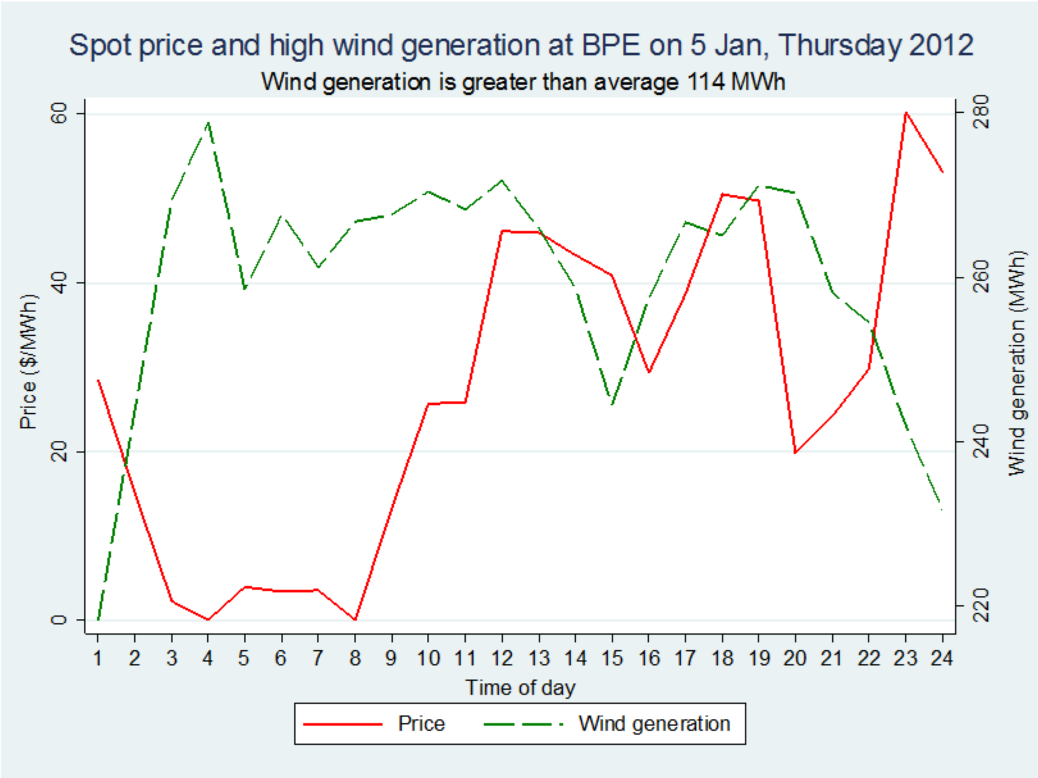
As shown in upper diagram in Figure 16, on 21 and 22 March, 2012, on average, there was a high level of wind generation. In general, there was a positive relationship between spot price and thermal generation. The price was high when thermal generation was high. Price changes seem to depend on thermal generation. Low price was found to prevail during the night; whereas, high price was found in the morning and in the evening, prices corresponded to peaks in demand. The relationship between prices and wind generation was unclear on 21 March, but was negative on 22 March.

Similarly, on 3 and 4 January 2012, the positive relationship between thermal generation and price was found, except between the hours of 1 am and 6 am on 3 January. Thus far, we have been unable to find a feasible explanation for this anomaly. No clear relationship was found between nodal price and wind generation.

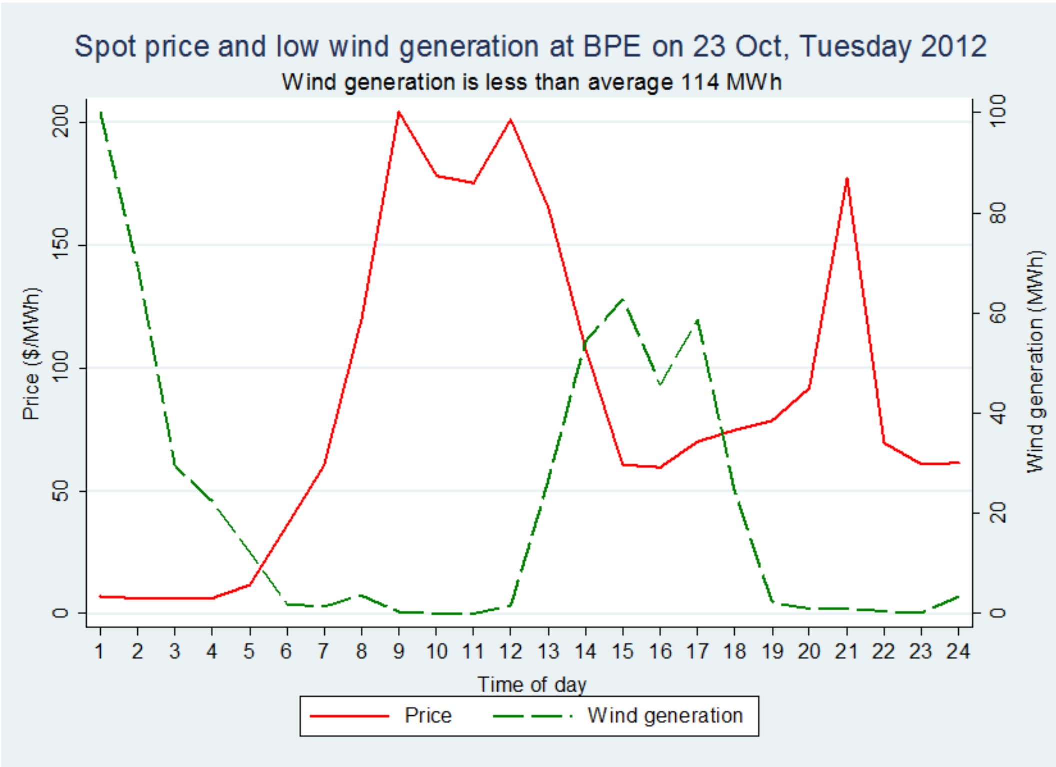
In summary, when wind share is small, this seems to have no impact on nodal price. Prices and thermal generation are positive correlated. It appears that the companies who generate thermal power would like to generate more electricity in order to obtain higher levels of profit from high nodal prices. This would be achieved by using more thermal generation to meet base and peak loads, which would further push up nodal prices.

Figure 12. Spot prices and wind generation at BPE

(1) High wind generation



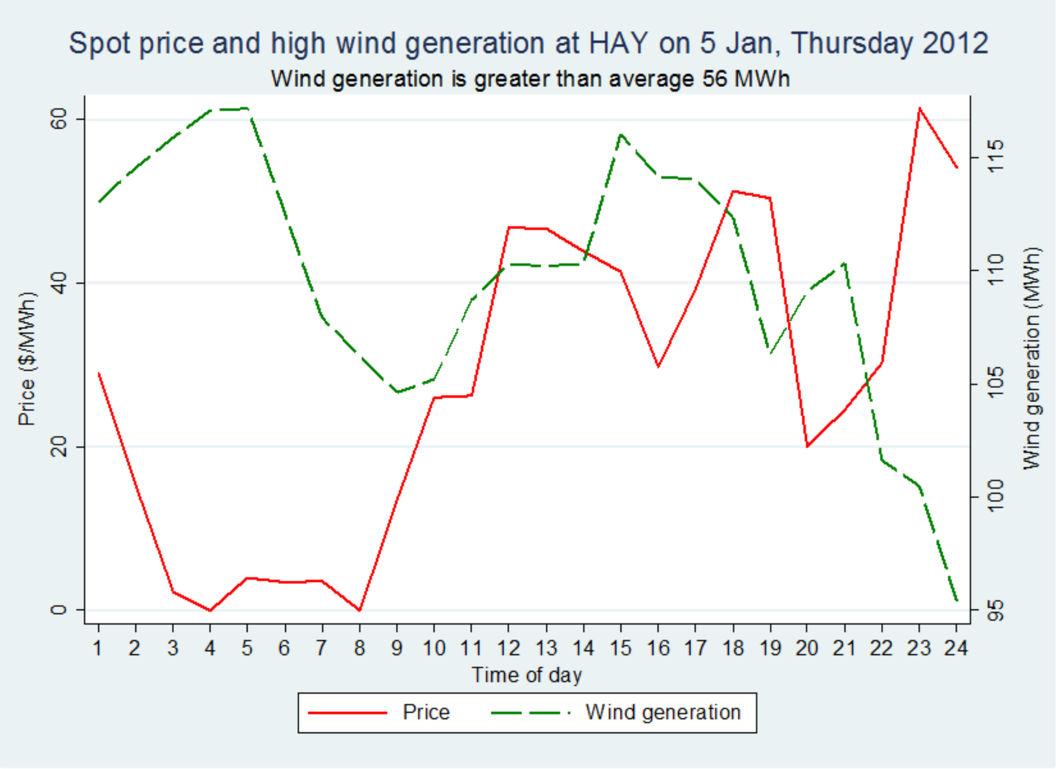
(2) Low wind generation



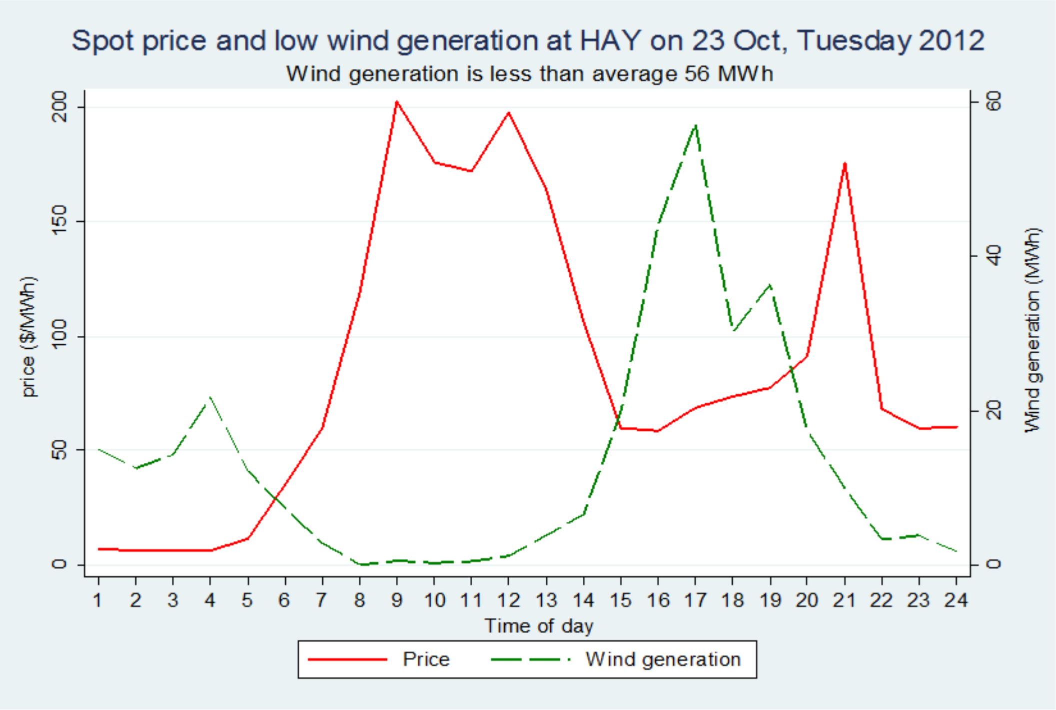
Source: Electricity Authority (EA), Centralised Dataset.

Figure 13. Spot prices and wind generation at HAY

(1) High wind generation



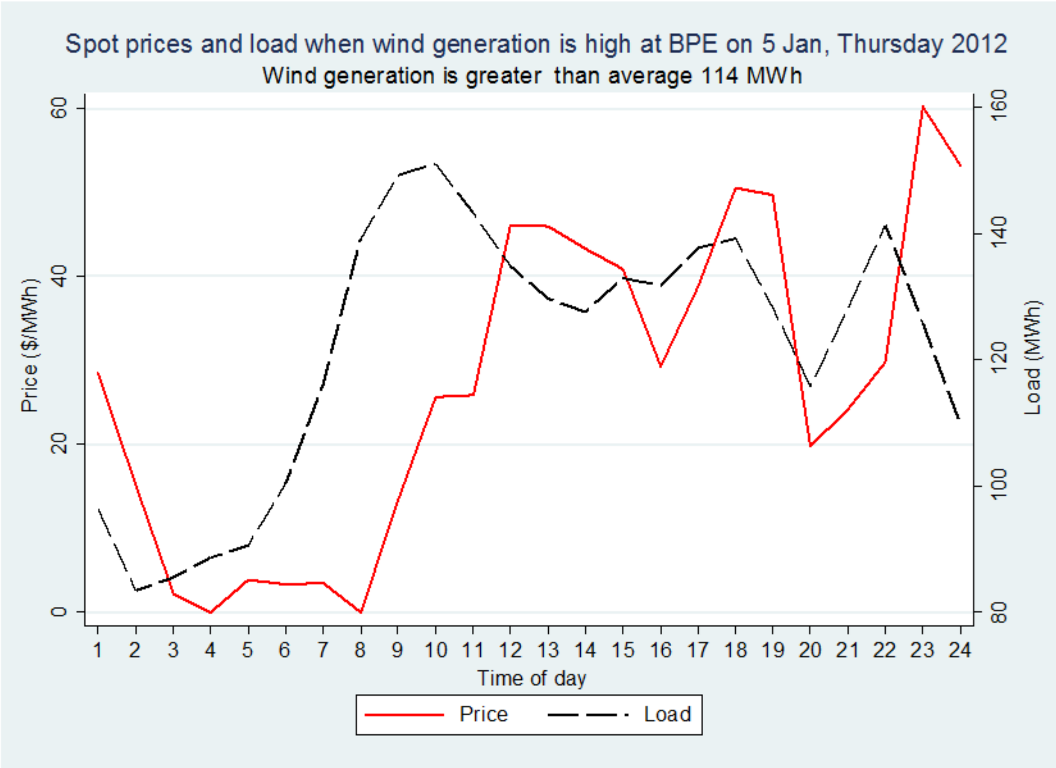
(2) Low wind generation



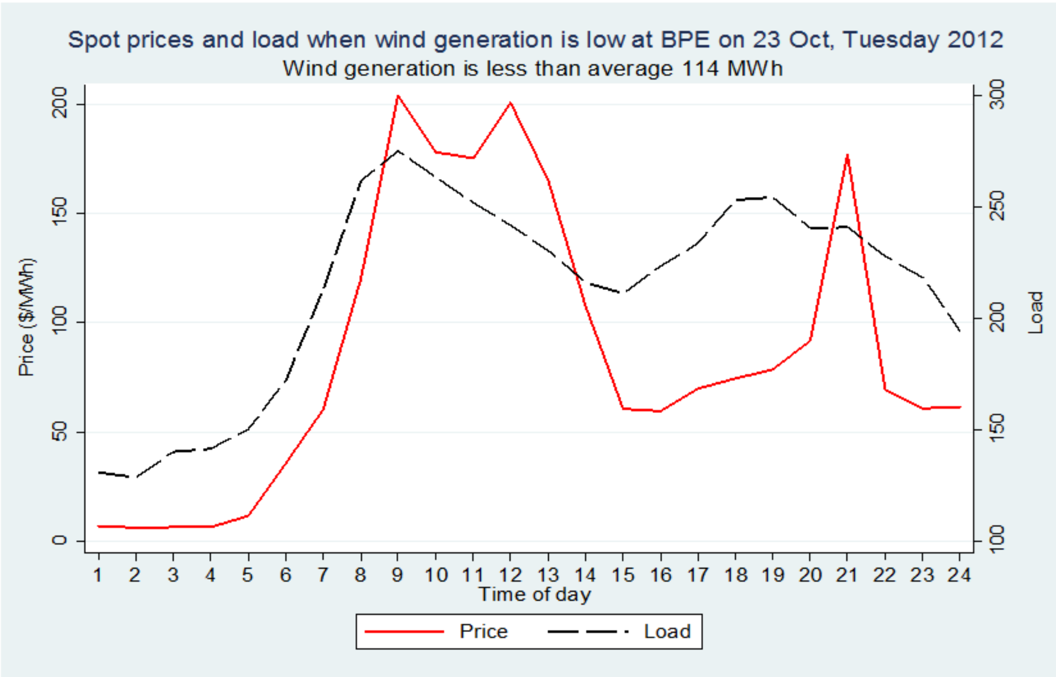
Source: Electricity Authority (EA), Centralised Dataset.

Figure 14. Spot prices and load at BPE

(1) High wind generation



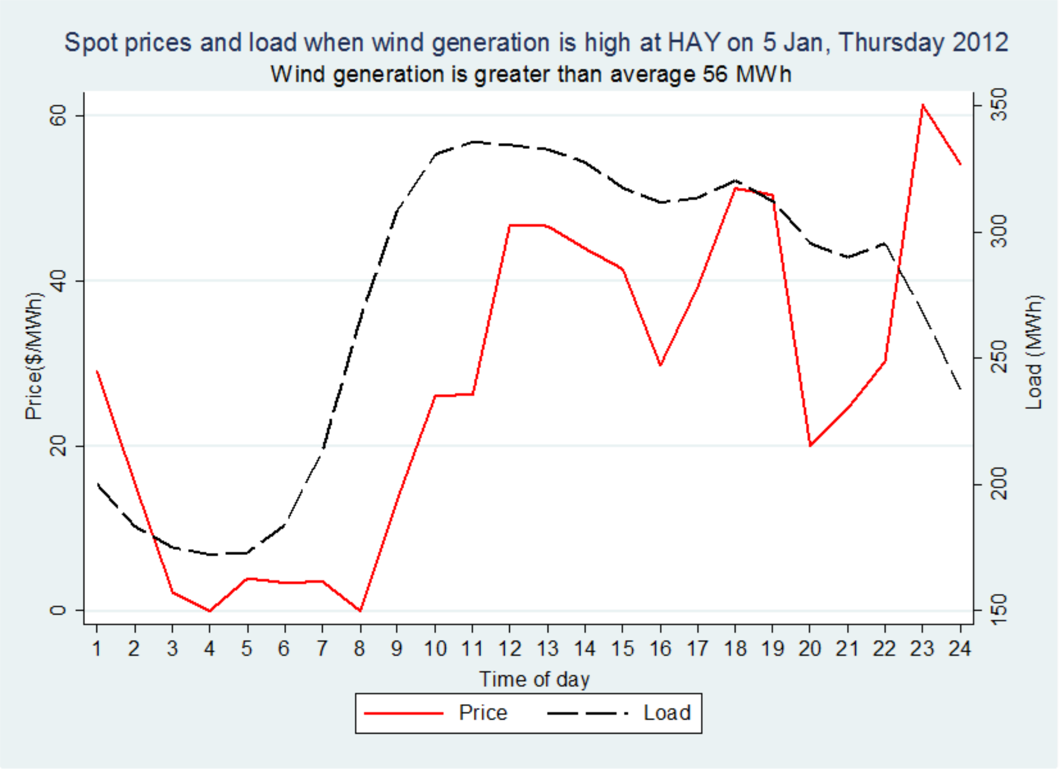
(2) Low wind generation



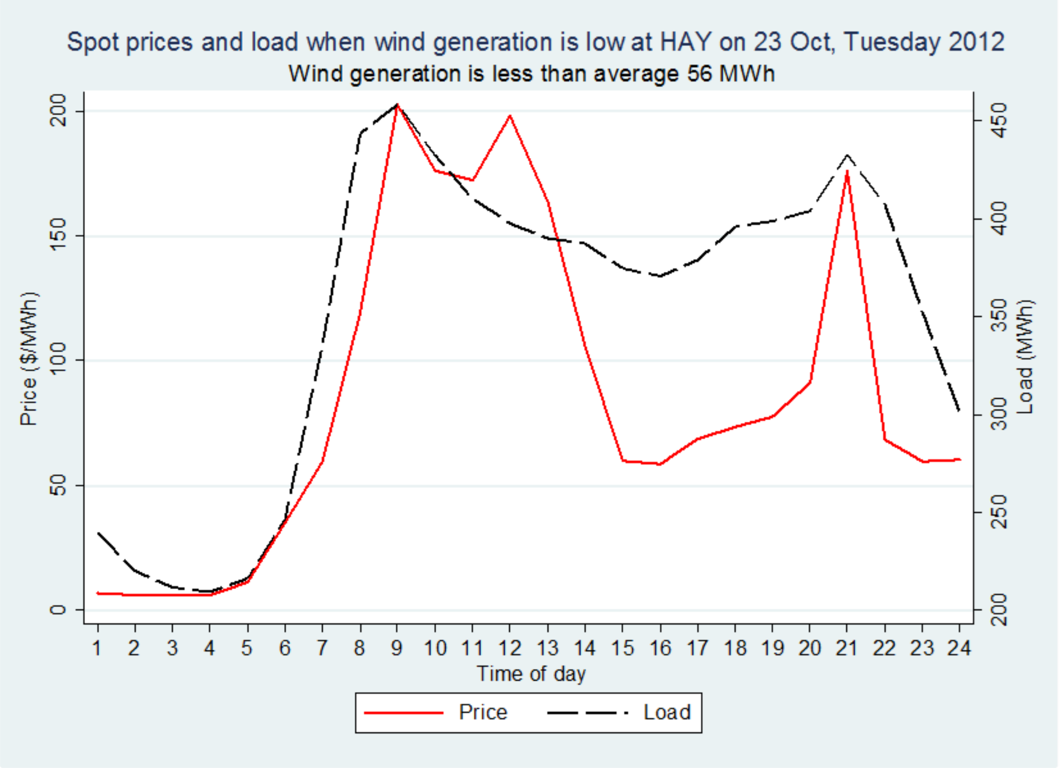
Source: Electricity Authority (EA), Centralised Dataset.

Figure 15. Spot prices and load at HAY

(1) High wind generation



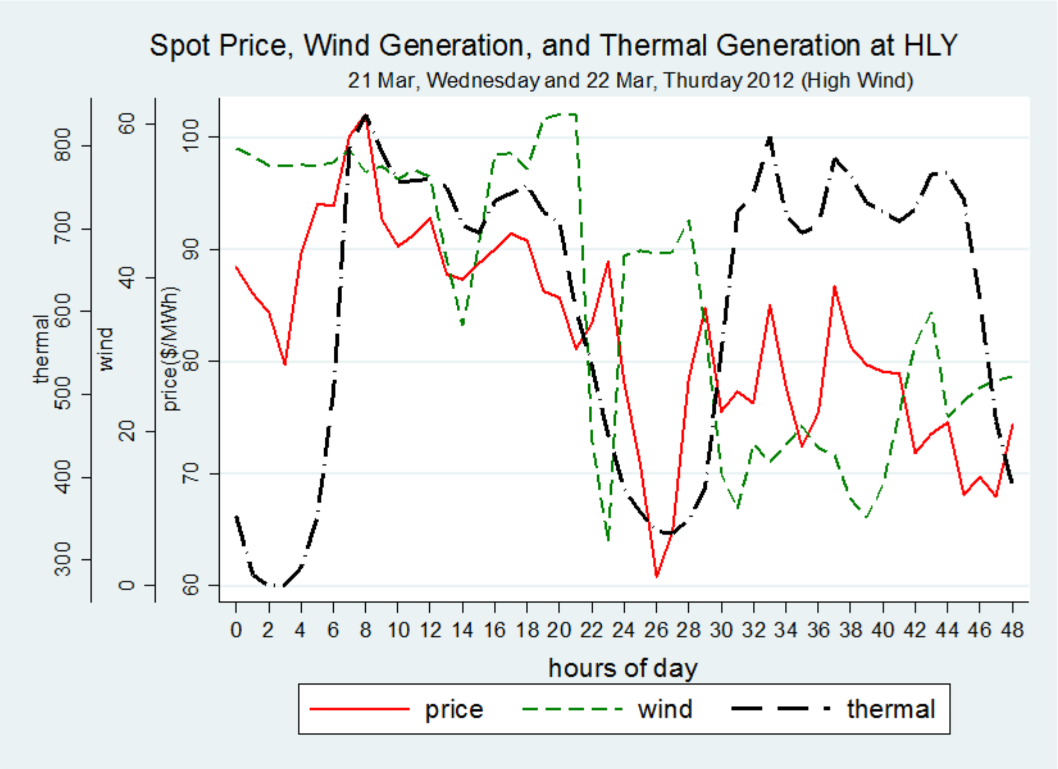
(2) Low wind generation



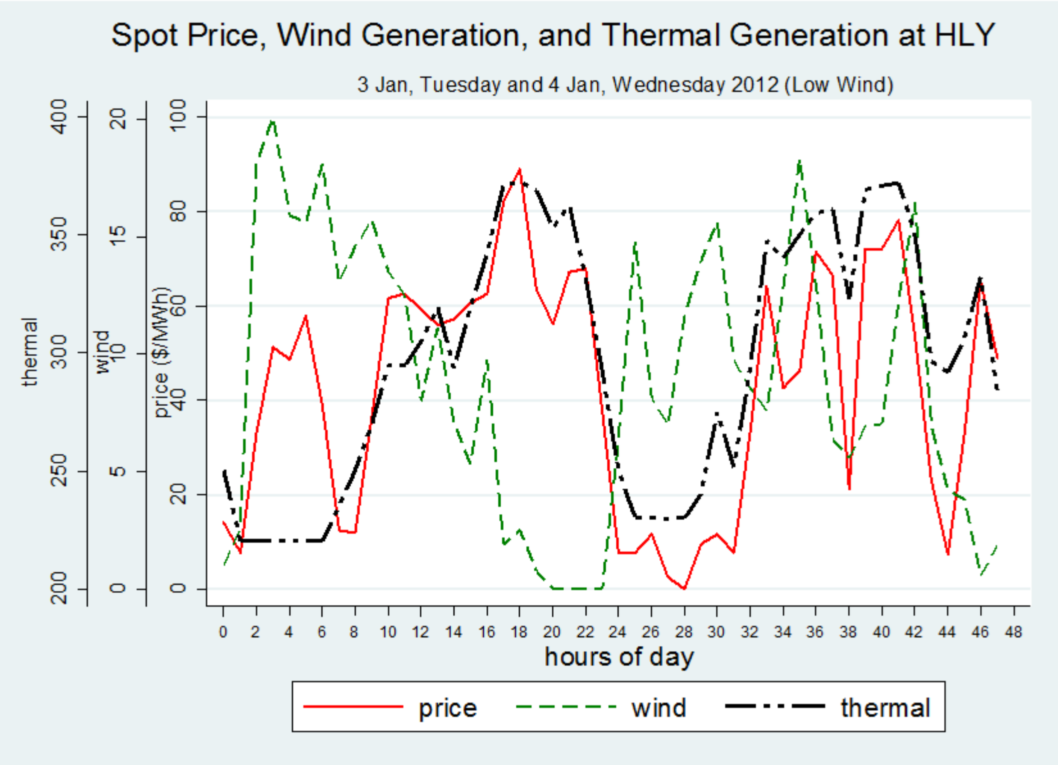
Source: Electricity Authority (EA), Centralised Dataset.

Figure 16. Spot prices, wind and thermal at HLY

(1) High wind generation



(2) Low wind generation



Source: Electricity Authority (EA), Centralised Dataset.

4. Econometric framework

New Zealand is a long narrow country, 1,600 km long with a maximum width of 400 km, and it consists of two main islands (the North and South Island). The electricity network between these two islands is linked by a High Voltage Direct Current (HVDC) transmission cable. The HVDC link plays a crucial role in balancing the electricity generation and demand between Islands.

Following Tobler's 'First Law of Geography' (Tobler, 1970), spatial dependence becomes weaker as nodes become more dispersed. Evidence from regression results indicates that spatial models perform better in the North Island rather than in New Zealand as a whole[14]. The plausible reason for this is that the larger distance between nodes located on the two islands weakens the spatial impact on nodal prices. Therefore, in this spatial analysis, we focus on the 6 nodes in the North Island; these are highlighted in blue in Figure 3.

Generation plants supplying the nodes referred to in the previous paragraph are reported in Table 1. To apply spatial analysis, the locations for those particular nodes are quantified and are represented by X and Y coordinates. Location in space is captured by the spatial weights matrix. The spatial weight matrix seen in Table 1 reveals spatial relationship among observations. It also gives information about which of the observations are neighbours and how their values are associated with each other. A spatial weight matrix is required to be "row-standardized" which means that the weights sum up to one on each of the rows. This matrix can be constructed based on either contiguity or distance. In our analysis, the 6 nodes are not contiguous; therefore, distance is used to construct the spatial weight matrix Nodes with distance d_{ij} receive a weight that is inversely proportional to the distance between the nodes and 0 if they are beyond a certain distance band D (Pisati, 2010).

The elements of row-standardized spatial weights matrices W are expressed as:

[14] Results are available on request. The high voltage direct-current (HVDC) transmission link integrates power supply between New Zealand's South (Benmore) and North (Haywards) Islands. The residual in the model captures the effects from nodes in the South Island.

$$w_{ij} = \frac{\frac{1}{d_{ij}}}{\sum_{j=1}^{6} \frac{1}{d_{ij}}} \quad (i, j = 1, \dots 6; i \neq j)$$

d_{ij} is the distance between nodes i and j.

The spatial weights matrices W is:

$$W = \begin{pmatrix} 0 & w_{12} & w_{13} & w_{14} & w_{15} & w_{16} \\ w_{21} & 0 & w_{23} & w_{24} & w_{25} & w_{26} \\ w_{31} & w_{32} & 0 & w_{34} & w_{35} & w_{36} \\ w_{41} & w_{42} & w_{43} & 0 & w_{45} & w_{46} \\ w_{51} & w_{52} & w_{53} & w_{54} & 0 & w_{56} \\ w_{61} & w_{62} & w_{63} & w_{64} & w_{65} & 0 \end{pmatrix}$$

The diagonal elements of the spatial matrix are set equal to zero and the non-diagonal elements are non-zero for observations that are spatially close to one another and zero for those that are distant from each other. There are no spatial effects if the distance band goes to zero. In this case, the spatial regression results approximate those of OLS. We set the distance band to the maximum distance for guaranteeing that all nodes have at least one neighbour. The spatial weight matrix is reported in Table 6.

Table 6. Spatial weights matrix (row-standardised)

	BPE	HAY	HLY	OTA	TKU	WKM
BPE	0	0.319532	0.125337	0.101925	0.266768	0.186438
HAY	0.413842	0	0.124990	0.107428	0.195570	0.158170
HLY	0.096994	0.074683	0	0.409360	0.172460	0.246503
OTA	0.095225	0.077495	0.494210	0	0.146525	0.186545
TKU	0.188337	0.106607	0.157335	0.110724	0	0.436997
WKM	0.128957	0.084472	0.220326	0.138108	0.428138	0

Moran’s I test statistic is used to test whether the data have spatial dependence. The significant positive spatial correlation found in Moran's I test (Moran’s I = 0.155 with p-value of 0.016) shows that a spatial econometrics model should be applied to estimate the impact of wind generation on nodal prices.

A general specification for spatial static model is written as follows[15]:

$$y_{it} = \alpha + \rho \sum_{j=1}^{n} w_{ij}\, y_{jt} + \sum_{k=1}^{K} X_{itk}\, \beta_k + \sum_{k=1}^{K}\sum_{j=1}^{n} w_{ij}\, X_{jtk}\, \theta_k + \psi load_{it} + \phi \sum_{j=1}^{n} w_{ij} load_{jt} + \sum_{i=1}^{3} M_i\, season_{it} + \pi weekday_{it} + \mu_i + \gamma_t + \nu_{it} \qquad (1)$$

$$\nu_{it} = \lambda \sum_{j=1}^{n} m_{ij}\, \nu_{it} + \varepsilon_{it} \qquad i = 1, \ldots, 11 \qquad t = 1, \ldots, T \qquad (2)$$

Where: y_{it} denotes nodal price for node i at time t; each y_i depends on a weighted average of other observations in y and Wy is the spatial lag of y; w_{ij} is the element of spatial weight matrix; ψ measures the effect of load on nodal price; ϕ measures the impact of load at neighbouring nodes on price; μ_i (i=1, …, n) are unobserved effects and are drawn from an independent and identically distributed (iid) standard Gaussian random variable; γ_t measures time effects; ρ measures the dependence of *yi* on nearby *y*; the significance of ρ indicates the impact of a given nodal price on neighbouring nodes; and, λ measures the spatial correlation in the errors.

Deterministic seasonal factors include a dummy variable weekday, that takes the value of 1 if the observation is on a weekday and zero if otherwise, with parameter π and three dummy season variables, these represent spring, summer and autumn. A set of two time-dependent dummy variables that account for season of the year (M_i), weekday (π) versus weekend.

Generation technology, such as wind, hydro and thermal, is represented by X which according to information from Table 1 is written as[16]:

[15] The augmented Dickey-Fuller unit-roots test is applied to test the null hypothesis that price, wind, geothermal, thermal and hydro follow unit root processes. The test results reject the null hypotheses. Those variables have no unit root process and they are stationary.

[16] Geothermal is excluded to avoid multicollinearity.

$$X = \begin{pmatrix} X_{1wind} & 0 & 0 \\ X_{2wind} & 0 & 0 \\ X_{3wind} & 0 & X_{3thermal} \\ 0 & 0 & X_{4thermal} \\ 0 & X_{5hydro} & 0 \\ 0 & X_{6hydro} & 0 \end{pmatrix}$$

The coefficient vector β is:

$$\beta = \begin{pmatrix} \beta_{wind} \\ \beta_{hydro} \\ \beta_{thermal} \end{pmatrix}$$

The matrix product WX denotes an average of the generation mix from neighbouring regions e.g., the nodal prices in node *j* depend on the generation which is generated by types of technologies in *j* as well as the generation in neighbouring nodes.

$$WX = \begin{pmatrix} w_{12}X_{2wind} + w_{13}X_{3wind} & w_{15}X_{5hydro} + w_{16}X_{6hydro} & w_{13}X_{3thermal} + w_{14}X_{4thermal} \\ w_{21}X_{1wind} + w_{23}X_{3wind} & w_{25}X_{5hydro} + w_{26}X_{6hydro} & w_{23}X_{3thermal} + w_{24}X_{4thermal} \\ w_{31}X_{1wind} + w_{32}X_{2wind} & w_{35}X_{5hydro} + w_{36}X_{6hydro} & w_{34}X_{4thermal} \\ w_{41}X_{1wind} + w_{42}X_{2wind} + w_{43}X_{3wind} & w_{45}X_{5hydro} + w_{46}X_{6hydro} & w_{43}X_{3thermal} \\ w_{51}X_{1wind} + w_{52}X_{2wind} + w_{53}X_{3wind} & w_{56}X_{6hydro} & w_{53}X_{3thermal} + w_{54}X_{4thermal} \\ w_{61}X_{1wind} + w_{62}X_{2wind} + w_{63}X_{3wind} & w_{65}X_{5hydro} & w_{63}X_{3thermal} + w_{64}X_{4thermal} \end{pmatrix}$$

The coefficient vector θ is:

$$\theta = \begin{pmatrix} \theta_{wind} \\ \theta_{hydro} \\ \theta_{thermal} \end{pmatrix}$$

WXθ is the vector of the average X_k over the neighbours of each node:

$$WX\theta = \begin{pmatrix} \theta_{wind}(w_{12}X_{2wind} + w_{13}X_{3wind}) + \theta_{hydro}(w_{15}X_{5hydro} + w_{16}X_{6hydro}) + \theta_{thermal}(w_{13}X_{3thermal} + w_{14}X_{4thermal}) \\ \theta_{wind}(w_{21}X_{1wind} + w_{23}X_{3wind}) + \theta_{hydro}(w_{25}X_{5hydro} + w_{26}X_{6hydro}) + \theta_{thermal}(w_{23}X_{3thermal} + w_{24}X_{4thermal}) \\ \theta_{wind}(w_{31}X_{1wind} + w_{32}X_{2wind}) + \theta_{hydro}(w_{35}X_{5hydro} + w_{36}X_{6hydro}) + \theta_{thermal}w_{34}X_{4thermal} \\ \theta_{wind}(w_{41}X_{1wind} + w_{42}X_{2wind} + w_{43}X_{3wind}) + \theta_{hydro}(w_{45}X_{5hydro} + w_{46}X_{6hydro}) + \theta_{thermal}w_{43}X_{3thermal} \\ \theta_{wind}(w_{51}X_{1wind} + w_{52}X_{2wind} + w_{53}X_{3wind}) + \theta_{hydro}w_{56}X_{6hydro} + \theta_{thermal}(w_{53}X_{3thermal} + w_{54}X_{4thermal}) \\ \theta_{wind}(w_{61}X_{1wind} + w_{62}X_{2wind} + w_{63}X_{3wind}) + \theta_{hydro}w_{65}X_{5hydro} + \theta_{thermal}(w_{63}X_{3thermal} + w_{64}X_{4thermal}) \end{pmatrix}$$

Two main approaches to the implementation of spatial econometrics for controlling spatial heterogeneity are currently in use. In this context, either the nodal price in one region is affected by the nodal price in neighbouring regions, or, the nodal price in one region is affected by the unknown characteristics of the neighbouring regions.

Depending on the value of parameters, we have a number of model specifications based on Elhorst (2014). If $\theta = 0$, then this applies a Spatial Autoregressive Model with Auto Regressive disturbances (SAC). If $\lambda = 0$, then this applies a Spatial Durbin Model (SDM). If $\lambda = 0 \; and \; \theta = 0$, then this applies a Spatial Autoregressive Model (SAR). If $\rho = 0 \; and \; \theta = 0$, then this applies a Spatial Error Model (SEM).

Among the four models (SAC, SAR, SEM and SDM), the results from the SDM model perform best[17].

In a spatial setting, the effect of an explanatory variable change in a particular unit affects not only that unit but also its neighbours (LeSage & Pace, 2009).

Based on LeSage and Pace (2009), the direct effect, indirect effect and total effect for a SDM model are given as follows:

$$direct\ effect_k = \frac{1}{n}\sum_{i=1}^{n}\frac{\partial y_i}{\partial x_{i,k}}$$

$$indirect\ effect_k = \frac{1}{n}\sum_{i=1}^{n}\sum_{j=1, i\neq j}^{n}\frac{\partial y_i}{\partial x_{j,k}}$$

$$total\ effect_k = \frac{1}{n}\sum_{i=1}^{n}\sum_{j=1}^{n}\frac{\partial y_i}{\partial x_{j,k}}$$

[17] We identify model specification based on the methods in Elhorst (2012) who gives an overview of the main restrictions that have been considered in the literature to get rid of the identification problem:

1. $\theta = 0$ to exclude exogenous interaction effects (WX) (test for SAR);
2. $\rho = 0$ to exclude contemporaneous endogenous interaction effects (WY);
3. If $\theta = -\beta\rho$, the model is a SEM (test for SEM).

Direct effects are applied to test the hypothesis as to whether a particular variable has a significant effect on the dependent variable in its own location, and indirect effects to test the hypothesis whether or not spatial spill-overs exist. Exogenous interaction effects, in which the generation at a particular location in some way depends on independent explanatory variables of the generation by other locations (Elhorst & Freret, 2009).

We report on three sets of estimations based on the whole of New Zealand including the North and South Islands, the North Island, and the four seasons in the North Island. Non-spatial models, such as OLS, fixed effects and random effects are applied to examine the effect of wind generation on price in New Zealand as a whole. The potential problem of "omitted unobservable bias" from OLS is addressed in the fixed or random effects models. The results are attached in Appendix B.

Three sets of estimations: impact of wind generation on prices

(1) New Zealand as a whole (Table A1)

a. Non-spatial model

Price= F_{1A} (wind, hydro, thermal, weekday, load, spring, summer, autumn)[18]

b. Spatial model

Price=F_{1AS} ((price, wind, hydro, thermal) in neighbour region, wind, hydro, thermal, weekday, load, spring, summer, autumn)

(2) North Island (Table A2)

c. Non-spatial model

Price= F_{2A} (wind, hydro, thermal, weekday, load, spring, summer, autumn)

d. Spatial fixed effects Durbin Model

[18] Geothermal generation is excluded in the model to avoid multicollinearity. The reference variables are weekend and winter.

Price=F_{2AS} ((price, wind, hydro, thermal) in neighbour region, wind, hydro, thermal, weekday, load, spring, summer, autumn)

(3) North Island by season (Table 7)

e. Spatial fixed effects Durbin Model

Price=F_{3S} ((price, wind, hydro, thermal) in neighbouring region, wind, hydro, thermal, weekday, load)

5. Results

This section examines the spatial impact of wind generation on nodal prices in the North Island electricity market. As discussed previously, half-hour nodal prices in the North Island are very different from prices in the South Island due to line constraints and line losses. The results would be biased if we estimated New Zealand as a whole; this is due to the aggregation error of prices. Moreover, the results from spatial lag estimation would be biased due to weaker dependence between the dispersed nodes across each island. To examine these hypotheses, we apply spatial fixed effects Durbin models on the New Zealand sample and the North Island sample[19], respectively. Among four models (SAC, SAR, SEM and SDM), results from the Spatial Durbin Model (SDM) perform best[20].

A specific characteristic of New Zealand's electricity system is that it is highly dependent on hydro generation and has limited water storage; this causes New Zealand to be vulnerable to dry years. We therefore look at the impact of wind in both dry seasons and wet seasons. Generally, 2012 was a dry year with dry periods before September and wet periods after September; this provides us with a good platform with which to analyse the impacts of wind generation on price level and price variance. The findings provide evidence for the management of supply security.

Due to the heterogeneity across different seasons, we decompose the North Island sample. Specific impacts of wind on nodal price are examined by season in the North Island electricity market. Estimation results are reported in Table 7.

---

[19] Results are in Appendix B.

[20] It has highest R squared value (0.325) and smallest AIC/BIC value which measures the goodness of fit. Results are available upon request. We also did separate tests for SAR, SEM, SAC and GSPRE models. Results reject the SAR, SEM, SAC and GSPRE models and accept the SDM model.

As seen in Table 7, results in spring are reported in columns (1) to (3), in summer they are reported in columns (4) to (6), in autumn in columns (7) to (9) and in winter, in column (10) to (12). Estimated the scalar summary effects are averaged over all 6 neighbourhoods in the sample.

Four types of generation technology (wind, hydro, thermal and geothermal) are used in New Zealand. Most of the nodes in this research use one type of technology except for HLY and WKM in the North Island. Most of the electricity in the South Island is generated by hydro power with a very small percentage being generated by wind power. In contrast, 54% of electricity in the North Island is generated by hydro power, followed by thermal energy (19%), geothermal energy (19%), and wind power (8%). This is due to, at most, two types of technology being present at each node; the magnitude of the average indirect effects coming from neighbouring nodes will be larger than those of the direct effects from its own node.

For each season we find negative and significant direct and indirect effects associated with changes in both types of neighbourhood wind generation, suggesting that the higher levels of wind generation in node *i* not only lead to a reduction in nodal prices in node *i*, but also to the nodal prices in neighbourhood node *j*.

Estimates of the direct effects (the main diagonal elements) indicate that a marginal increase of 1MW in wind generation in node *i* is associated with a reduction of $0.05 to $0.2 per MWh in nodal price in node *i*.

Estimates of the indirect effects (spatial spill-overs, the off-diagonal elements) show that spatial spill-over effects from changes in wind generation in neighbourhood node *i* lead to a cumulative decrease in nodal prices. The estimate for scalar indirect effect cumulates in spill-overs affecting immediately neighbouring regions, and in addition, the neighbours of these regions and the neighbours of the neighbours of the regions, and so on. In other words, a change in the wind generation of one node impacts upon the price at neighbouring nodes, as well as the neighbours to those neighbouring nodes, and so on. The magnitude of the spill-over effects on immediate neighbours would be greater than those on more distant neighbourhoods. The indirect effects for wind generation are that a 1MW increase in wind generation at neighbouring node is associated with a price drop of 0.27 $ to 0.94 $ per MWh.

Estimates of the total effects reflect the sum of the direct plus indirect effects. The total effect is that a marginal increase of 1MW in wind generation is associated with a reduction of 0.31 to 1.2 $ per MWh in nodal price.

Estimates of the total effects of a 100 MWh increase in wind generation on nodal prices are a reduction of $86.4/MWh in spring, $116.1/MWh in summer, $106.9/MWh in autumn, and $32.2/MWh in winter; these are statistically-significant effects.

With regard to the statistically-significant coefficients for load support, our hypothesis is that rising loads raise nodal prices. The magnitude effects of load on prices are uneven for the four seasons. A 100 MWh load increase in spring has more than a $51/MWh effect. By contrast, the same 100 MWh load increase in winter raises prices by $9/MWh. This evidence may indicate that there are small variations in load, or low elasticity of demand, in winter. Also, in the spring of 2012, there was a northward electricity import via the HVDC link from the Benmore Power Station in the South Island to Hayward Substation in the North Island.

More wind injected into the grid lowers the nodal price, and this result is not sensitive to the electricity demand[21]. The spatial regression results have re-assured our previous statistical analysis in section 2. Wind speed in one wind site is complementary with wind speed in another wind site. Surplus wind generated electricity can be exported to neighbourhood nodes, which reduces nodal price. The results provide evidence that the benefits of wind farms constructed at sites with a good wind resource, at scale, are distributed through the network, provided of course that network capacity is not a limiting factor. On the other hand, smaller scale wind farms should be located close to communities rather than more distant from main load centres avoiding transmission costs.

Adding 1MW hydro supply lead reduction in nodal price by 0.13$ in both summer and winter and to 0.34$ in spring. There was no significant effect of hydro generation on price in autumn when the storage level was low and hit a historical hydro risk curve (Figure 7).

[21] We have examined models with and without load, and found the similar effects of wind generation on nodal prices. This indicates that wind generation is not sensitive to demand.

However, the coefficients for thermal power change significantly from spring to winter. In summer and winter, as one of the expensive types of electricity generation, thermal generation has an opposite effect on nodal prices to that of wind farms. Because the cost of electricity generation is relatively high from thermal plants, the more electricity is generated by thermal plants, the higher the price will be. This can be explained by shifting the merit-order supply curve to the left after substituting hydro generation with thermal generation. Consequently, there is a positive impact from thermal generation on nodal prices. The surplus of electricity generated by thermal plants exported to neighbourhood nodes is expected to increase a neighbourhood nodal price due to the high cost of generation. The total effect is that a marginal increase of 1 MWh in thermal generation caused a rise of 0.21$ per MWh in summer and 0.16$ per MWh in winter. The 1MW increase in neighbourhood thermal generation was associated with a price rise by 0.18 $ per MWh in summer and 0.14 $ per MWh in winter.

To the contrary, in autumn, 0.41 $ per MWh was reduced in nodal price by adding 1 MW generated by thermal plants. The insignificance of the coefficient on hydro may provide a hint to explain this controversial effect. In 2012, the amount of controlled storage continued to fall from January onwards (Figure 7), as a result, the opportunity cost of water was expected to rise, and hydro generators preferred to save water for generating later. This would exaggerate the supply constraints and drive nodal prices up until the hydro level was restored from its natural seasonal cycle. Van Campen et al. (2011) found that during dry years the inflows into the South Island storage lakes are insufficient and hydro electricity generation is consequently limited, resulting in more thermal generation, higher spot prices, and security of supply concerns. With high water value during dry periods, the short run marginal cost (SRMC) of hydro may exceed that of thermal. After substituting hydro with thermal generation given that everything else holds constant, this would shift the supply curve to the right. In this situation, adding thermal generation would reduce nodal prices.

Rising loads tend to raise nodal prices. The magnitude effects of load on prices are uneven for four seasons. A 100 MWh load increase in spring has more than a 51$/MWh effect. In contrast, the same 100 MWh load increase in winter raises the price by $9/MWh.

Table 7: The Spatial Fixed Effects of Wind Generation on Nodal Price 2012 (North Island by Season - A Spatial Durbin Model (SDM))

Dependent variable: The nodal prices in 2012 dollars ($/MWh)

	Sample: North Island by Season											
	spring			summer			autumn			winter		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
VARIABLES	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total
wind	-0.145***	-0.719***	-0.864***	-0.203***	-0.957***	-1.161***	-0.190***	-0.879***	-1.069***	-0.0490***	-0.273***	-0.322***
	(0.0104)	(0.0516)	(0.0619)	(0.00593)	(0.0292)	(0.0351)	(0.00693)	(0.0338)	(0.0406)	(0.00549)	(0.0259)	(0.0313)
hydro	-0.0616***	-0.276***	-0.338***	-0.0292***	-0.0971***	-0.126***	-0.0121***	-0.00379	-0.0159	-0.0271***	-0.103***	-0.130***
	(0.00621)	(0.0309)	(0.0371)	(0.00317)	(0.0155)	(0.0187)	(0.00399)	(0.0193)	(0.0233)	(0.00275)	(0.0132)	(0.0159)
thermal	0.00905	0.0479	0.0570	0.0317***	0.181***	0.213***	-0.0116***	-0.0293**	-0.0409**	0.0205***	0.143***	0.163***
	(0.00612)	(0.0304)	(0.0365)	(0.00229)	(0.0112)	(0.0135)	(0.00268)	(0.0133)	(0.0160)	(0.00176)	(0.00891)	(0.0106)
Weekday	-0.344	-1.577	-1.921	1.896***	7.745***	9.642***	4.581***	17.39***	21.97***	1.338***	4.466***	5.803***
	(0.582)	(2.670)	(3.252)	(0.329)	(1.343)	(1.672)	(0.399)	(1.518)	(1.917)	(0.365)	(1.220)	(1.585)
load	0.0910***	0.417***	0.508***	0.0416***	0.170***	0.211***	0.0564***	0.214***	0.270***	0.0203***	0.0677***	0.0880***
	(0.00457)	(0.0213)	(0.0258)	(0.00247)	(0.0102)	(0.0127)	(0.00285)	(0.0112)	(0.0140)	(0.00210)	(0.00715)	(0.00924)
rho (spatial)			0.983***			0.959***			0.944***			0.914***
			(0.000299)			(0.000709)			(0.000995)			(0.00150)
sigma2_e (Variance)			6.292***			9.843***			23.60***			39.23***
			(0.0861)			(0.134)			(0.320)			(0.528)
Observations			13,104			13,104			13,248			13,248
R-squared			0.121			0.521			0.337			0.337
Number of id			6			6			6			6

Notes: Positive significant spatial parameter rho (ρ) indicates that spatial lagged models rather than spatial error models are employed into the spatial analysis.
Standard errors in parentheses *** p<0.01, ** p<0.05, * p<0.1.
Source: Source: Electricity Authority (EA), Centralised Dataset.

Our results show that ignoring spatial spill-overs leads to an underestimation of the impact of wind generation on nodal prices. The ability of spatial regression models to provide quantitative estimates of spill-over magnitudes and to allow statistical testing for the significance of these represents a valuable contribution of spatial regression models to understanding electricity prices.

After analysing the correlation between the hydro storage levels of the South Island and electricity prices, Suomalainen et al. (2010) found that anomalies in a particularly low level of storage causes high fluctuations and spikes in price and they explained that the uncertainty of the severity of the coming unavailability of this inexpensive energy resource during the ensuing months of high demand leads to this situation.

Increasing wind generation capacity not only tends to reduce nodal prices, but also tends to increase the variance of nodal prices. Following the method used by Woo et al. (2011), we studied the effects of a 10% increase in wind generations installed capacity on changes in price and price variance.

Table 8. The seasonal price effects of a 10% increase in wind generation's installed capacity

The seasonal price effects of a 10% increase in wind generation's installed capacity				
	spring	summer	autumn	winter
Estimates of wind (βwind)	-0.864	-1.161	-1.069	-0.322
	(0.0619)	(0.0351)	(0.0406)	(0.0313)
Price change as percent of price mean	-11.44	-9.04	-7.34	-2.25
Price variance change as percent of price variance	21.68	40.24	32.89	3.21

Table 8 shows the price effects of a 10% increase in the installed wind generation capacity by season in the North Island. The price reduction varies among seasons. It ranges from 2.25% in winter to 11.44% in spring. The larger extent of price reduction is in accordance with the larger variance changes except in spring. This is consistent with the results of Ketterer (2014) and Woo et al. (2011). Integrating and balancing the electricity system would be crucial for reducing the volatility of the nodal price when expanding wind generation. A better integration of wind into grid can be achieved after managing to reduce price volatility, such as promoting plug-in hybrid electric vehicles or installing pumped-storage.

In spring 2012, electricity was imported from the South Island to the North Island via HVDC link. The amount of electricity, mainly generated by hydro in the South Island, balanced the shortage of electricity in the North Island. In this situation, the price variation from wind would have been reduced by hydro generation.

6. Conclusion

The study has examined the merit-order effect of wind generation on nodal prices and price variance in the New Zealand electricity market based on the centralised dataset. The study addresses the heterogeneity that is important for electricity price analysis, and it extends the literature as follows. First, a spatial econometric model was applied to examine the effect on nodal price of wind generation in the New Zealand. Second, the impact of other types of generation mix on nodal prices was examined. Third, because the NZEM is a hydro-dominated electricity system, nodal prices are very sensitive to hydro storage which affects the steepness of the merit-order supply curve. We evaluated these effects during dry periods and wet periods, respectively. Four, price volatility was estimated using the spatial econometricmodel.

In this paper, we have been able to shed additional light on the issue of local geographic spill-overs between nodal prices and wind generation. Overall, we have confirmed the negative and significant relationship between nodal prices and wind generation, both directly and indirectly. Our findings are important in that they highlight the relevance of considering the spatial range of interaction in the analysis of spatial externalities.

The evidence indicates that, after controlling for unobserved heterogeneity, there are negative spatial spill-overs for wind power. Using a spatial Durbin (SDM) model we estimated the direct effects of a marginal increase of 100 MW in wind generation at node *i* are associated with a reduction in the price at node *i* of $4.9 per MWh during the winter months and $20 per MWh during the summer months. The indirect effects of a 100 MW increase in wind generation at neighbouring nodes are associated with a price drop of $27.3 in winter and $95.7 per MWh in summer. Point estimates of the total effect of a 100 MWh increase in wind generation on nodal prices are a reduction of $86.4/Mwh in spring, $116/MWh in summer, $106.9/MWh in autumn, and $32.2/MWh in winter, and these effects are statistically significant. While increased wind generation reduces the nodal price; it also increases the variance of that price.

Adding more intermittent wind generation into an electricity system creates challenges for the system operator and market participants. On the one hand, electricity generated by wind is independent and non-adjustable with respect to electricity demand. High levels of variable renewable electricity production can be balanced by adjusting the output from conventional power plants or by exporting excess electricity. Importing and exporting electricity is not possible in New Zealand. Therefore, promoting plug-in hybrid electric vehicles maybe an option to mitigate more wind generation from the demand response (Wang et al., 2011). On the other hand, the availability of quick start generation capacity is required to meet electricity demand during times of too little wind. Pumped-storage solves the problem by storing excess wind production. According to MBIE (2013), new pumped hydro stations capacity will be available during the period 2015-2050.

The outcome of price volatility in the wind-hydro system and in the wind-thermal-hydro system is of interest. The findings are expected to provide important evidence for requiring security of supply management which stabilizes the balance between wind capacity and conventional capacity, the balance between electricity supply and demand.

References

Anselin, L., Varga, A., & Acs, Z. (1997). Local geographic spillovers between university research and high technology innovations. *Journal of urban economics, 42*(3), 422-448.

Browne, O., Poletti, S. and Young, D. (2012) Simulating market power in the New Zealand electricity market. *New Zealand Economic Papers, 46(1)*, 35-50.

Browne, O., Poletti, S. and Young, D. (2014) Will Wind Kill Energy-Only Electrictiy Markets? http://docs.business.auckland.ac.nz/Doc/Online-Appendix_Will-wind-kill-energy-only-markets.pdf

Boschma, R. (2005). Proximity and innovation: a critical assessment. *Regional studies, 39*(1), 61-74.

Carlino, G. A., Chatterjee, S., & Hunt, R. M. (2007). Urban density and the rate of invention. *Journal of urban economics, 61*(3), 389-419.

Cutler, N. J., Boerema, N. D., MacGill, I. F., & Outhred, H. R. (2011). High penetration wind generation impacts on spot prices in the Australian national electricity market. *Energy Policy, 39*(10), 5939-5949.

Duranton, G. (2007). Urban evolutions: The fast, the slow, and the still. *The American Economic Review, 97*(1), 197-221.

New Zealand Wind Energy Association (NZWEA), see www.windenergy.org.nz/operating-&-under-construction for data on existing and consented wind farms (last accessed January, 2016). http://www.windenergy.org.nz/wind-energy/nz-windfarms.

Electricity Authority (EA), Centralised Dataset, version, 2013.

Electricity Authority-Electricity Market Information (EA-EMI), see www.emi.ea.govt.nz for data on electricity supply (last accessed August, 2016).

Electricity Authority. (2016). Electricity in New Zealand. ENZ (2016).Retrieved from file:///C:/Users/lwen011/Downloads/Electricity-in-New-Zealand-2016.pdf

Electricity Authority. Electricity Market Performance: A Review of 2012. EMR (2012). https://www.ea.govt.nz/monitoring/year-in-review/2012-review-of-electricity-market-performance/

Electricity Authority. Electricity Market Performance 2015. https://www.ea.govt.nz/monitoring/year-in-review/2015/

Electricity Commission, “2008 Statement of Opportunities,” the SOO2008 report.

Elhorst, J., & Freret, S. (2009). Yardstick competition among local governments: French evidence using a two-regimes spatial panel data model. *Journal of Regional Science, 49*, 931-951.

Elhorst, J. (2012). Spatial Panels. *Spatial Economic Analysis*, *5*, 9-28.

Elhorst, J. P. (2014). Spatial panel data models *Spatial Econometrics* (pp. 37-93): Springer.

Ellison, G., Glaeser, E. L., & Kerr, W. R. (2010). What causes industry agglomeration? Evidence from coagglomeration patterns. *The American Economic Review, 100*(3), 1195-1213.

Escribano, A., Ignacio Peña, J., & Villaplana, P. (2011). Modelling Electricity Prices: International Evidence*. *Oxford Bulletin of Economics and Statistics, 73*(5), 622-650. 10.1111/j.1468-0084.2011.00632.x

Faggian, A., & McCann, P. (2009). Human capital, graduate migration and innovation in British regions. *Cambridge Journal of Economics, 33*(2), 317-333.

Jónsson, T., Pinson, P., & Madsen, H. (2010). On the market impact of wind energy forecasts. *Energy Economics, 32*(2), 313-320. http://dx.doi.org/10.1016/j.eneco.2009.10.018

Ketterer, J. C. (2014). The impact of wind power generation on the electricity price in Germany. *Energy Economics, 44*, 270-280. http://dx.doi.org/10.1016/j.eneco.2014.04.003

LeSage, J. P., & Pace, R. K. (2009). *Introduction to Spatial Econometrics (Statistics, textbooks and monographs)*: CRC Press.

Malafeh, S. & Sharp, B. (2015). Role of royalties in sustainable geothermal energy development. *Energy Policy,* 85, 235–242. (unpublished).

Ministry of Business, Innovation & Employment (MBIE). New Zealand's energy outlook—Electricity insight. MBIE (2013).

Ministry of Business, Innovation and Employment (MBIE). Energy in New Zealand. ENZ (2015). Retrieved from http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/publications/energy-in-new-zealand/energy-in-nz-2015.pdf.

Ministry of Business, Innovation and Employment (MBIE). Energy in New Zealand. MBIE (2016). Retrieved from http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/publications/energy-in-new-zealand/energy-in-nz-2016.pdf.

Ministry of Economic Development (MED). Energy in New Zealand (ENZ) 2013. New Zealand Government.

McRae, S. D., & Wolak, F. A. (2009). How do firms exercise unilateral market power? Evidence from a bid-based wholesale electricity market.

McRae, S. D., & Wolak, F. A. (2014). How do firms exercise unilateral market power? Empirical evidence from a bid-based wholesale electricity market. The Manufacturing of Markets: Cambridge University Press.

Mellander, C., Florida, R., & Stolarick, K. (2011). Here to stay—the effects of community satisfaction on the decision to stay. *Spatial Economic Analysis, 6*(1), 5-24.

Morthorst, P.E. 2007. Impacts of Wind Power on Power Spot Prices, RISO National laboratory.

Munksgaard, J., & Morthorst, P. E. (2008). Wind power in the Danish liberalised power market—Policy measures, price impact and investor incentives. *Energy Policy, 36*(10), 3940-3947. http://dx.doi.org/10.1016/j.enpol.2008.07.024

New Zealand Wind Energy Association (NZWEA). New Zealand's Wind Farms. Retrieved from http://www.windenergy.org.nz/wind-energy/nz-windfarms

New Zealand Wind Energy Association (NZWEA). Wind Energy 2030:The Growing Role for Wind Energy in New Zealand's Electricity System. http://www.windenergy.org.nz/store/doc/Wind_Energy_2030_Document_Web.pdf

Nicholson, E., Rogers, J., & Porter, K. (2010). Relationship between Wind Generation and Balancing Energy Market Prices in ERCOT: 2007-2009. NREL Report SR-5500-49415. National Renewable Energy Laboratory (NREL).

Nicolosi, M., & Fürsch, M. (2009). The impact of an increasing share of RES-E on the conventional power market—the example of Germany. *Zeitschrift für Energiewirtschaft, 33*(3), 246-254.

Pisati, M. 2010. Tools for spatial data analysis. Stata Technical Bulletin 60.

Pöyry (2010). Wind Energy and Electricity Prices. Exploring the 'merit order effect'The challenges of intermittency in North West European power markets. European Wind Energy Association (EWEA) 2010. Summary Report (http: //www.poyry.co.uk).

Sáenz de Miera, G., del Río González, P., & Vizcaíno, I. (2008). Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain. *Energy Policy, 36*(9), 3345-3359. http://dx.doi.org/10.1016/j.enpol.2008.04.022

Sensfuß, F., Ragwitz, M., & Genoese, M. (2008). The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. *Energy Policy, 36*(8), 3086-3094. http://dx.doi.org/10.1016/j.enpol.2008.03.035

Suomalainen, K., Pritchard, G., Sharp, B., Yuan, Z., & Zakeri, G. (2015). Correlation analysis on wind and hydro resources with electricity demand and prices in New Zealand. *Applied Energy, 137*, 445-462.

Status Review of Renewable and Energy Efficiency Support Schemes in Europe in 2012 and 2013. Coucil of European Energy Regulators (CEER); 2015.

The National Institute of Water and Atmospheric Research (NIWAR). Generating Synthetic Wind Data. https://www.niwa.co.nz/environmental-information/research-projects/synthetic-wind-data.

Tipping J., Read E.G., & McNickle, D. (2004). The Incorporation of Hydro Storage into a Spot Price Model for the New Zealand Electricity Market. Presented at the Sixth European Energy Conference: Modelling in Energy Economics and Policy. Zurich, 2004. Available at http://www.mang.canterbury.ac.nz/research/emrg/

Tobler, W. 1970. A computer movie simulating urban growth in the Detroit region. *Economic Geography*, 46: 234–40.

van Campen, B. (2010). Efficiency and Fuel Switching in Norway and New Zealand's Residential Electricity Sector during Droughts. 33rd International Association for Energy Economists (IAEE) Conference: The Future of Energy: Global Challenges, Diverse Solutions. Rio de Janerio, Brazil: International Association for Energy Ecnomics.URL: http://hdl.handle.net/2292/28509

van Campen, B., Poletti, S., Young, D.,& Zakeri,G. (2011). A Guide to the New Zealand Electricity Market. University of Auckland Energy Centre.

von der Fehr, N.H.M.(2009) Peer Review of Professor Wolak Report.file:///C:/Users/lwen011/Downloads/comcom-nilshenrikpeerreviewofwolakreport-may2009.pdf

Wang, J., Liu, C., Ton, D., Zhou, Y., Kim, J., & Vyas, A. (2011). Impact of plug-in hybrid electric vehicles on power systems with demand response and wind power. *Energy Policy, 39*(7), 4016-4021. http://dx.doi.org/10.1016/j.enpol.2011.01.042

Whiten, B., McDonald, B., & Bedford, R. (2013). Modelling power output from correlated wind farms. *ANZIAM Journal*, *53*, 104-141.

Wolak, F. (1997). Market Design and Price Behavior in Restructured Electricity Markets: an International Comparison. Working Paper, Department of Economics Stanford University.

Wolak, Frank F. (2007). Quantifying the Supply-Side Benefits from Forward Contracting in Wholesale Electricity Markets, *Journal of Applied Econometrics*, 22, 1179-1209.

Wolak, F. (2009). An Assessment of the Performance of the New Zealand Wholesale Electricity Market. Report for the Commerce Commission. Retrieved from http://www.comcom.govt.nz/investigation-reports/

Woo, C. K., Horowitz, I., Moore, J., & Pacheco, A. (2011). The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. *Energy Policy*, *39*(7), 3939-3944. http://dx.doi.org/10.1016/j.enpol.2011.03.084

Appendix A. Spatial Durbin Model

The spatial Durbin model is

$$y \quad = \rho W y + X\beta \quad + \; WX\,\theta \quad + \; u \qquad\qquad (1)$$

WX is the average-neighbour values of the independent variables; e.g. the nodal prices in node j depend on generation which generated by types of technologies in j as well as generation in neighbouring nodes. Each y_i depends on a weighted average of other observations in y and Wy is known as a spatial lag of y.

$$(I - \rho W) y \quad = X\beta \quad + \; WX\,\theta \quad + \; u$$

$$y \quad = (I - \rho W)^{-1}(X\beta \quad + \; WX\,\theta \quad + \; u)$$

Based on the Notes on Spatial Econometric Models (Philip A. Viton, 2010), where I is the identity matrix

If $|\rho|<1$, then $(I - \rho W)^{-1} = I + \rho W + \rho^2 W^2 + \rho^3 W^3 + \cdots$

W is the spatial weights of the neighbours of a given region. W^2 is the weights of the neighbours of the neighbours, W^3 is the weights of the neighbours of the neighbours of the neighbours, etc. This is the sum of a series of decreasing influences of the entire spatial system.

To analyse the spatial effects, location in space is to be quantified and to be represented by latitude and longitude. In equation (1), the location in space is captured by the spatial weights matrix W which depreciates the effects of the other observations by some distance-related characteristic. The strength of spatial dependence is expected to decline with distance due to increasing geographical impediments.

Y is the 6×1 vector of observations on the dependent variable. X is the 6×3 matrix of observations on the independent variables. W is the 6×6 spatial-weighting matrices that characterize the distance between neighbourhoods. u are spatially correlated residuals and ε are independent and identically distributed disturbances λ and ρ are scalars that measure, respectively, the dependence of yi on nearby y and the spatial correlation in the errors.

Appendix B. Other Estimation Results

Table A1 Nodal Price 2012 (New Zealand)

	Dependent variable: The nodal prices in 2012 dollars ($/MWh)		
	Sample: New Zealand		
	(1)	(2)	(3)
VARIABLES	OLS	Panel fixed effects	A Spatial Durbin Model (SDM)
wind	-0.0822***	-0.0974***	-1.135***
	[0.004]	[0.005]	(0.0595)
hydro	-0.0053***	-0.0330***	-1.573***
	[0.001]	[0.002]	(0.0218)
thermal	-0.0069***	0.0114***	-1.525***
	[0.001]	[0.002]	(0.0315)
load	0.0055***	0.1205***	2.212***
	[0.001]	[0.002]	(0.0340)
Weekday	13.1283***	10.5639***	11.44***
	[0.383]	[0.380]	(2.277)
Spring	-46.6317***	-41.7929***	-47.83***
	[0.491]	[0.491]	(2.682)
Summer	-0.4253	4.9706***	31.22***
	[0.490]	[0.490]	(2.772)
Autumn	22.6965***	24.6495***	45.99***
	[0.488]	[0.483]	(2.250)
Constant	81.9578***	52.7867***	/
	[0.528]	[0.817]	/
F-test	2900	3397	/
R2	0.194	0.0777	0.110
R2_W	/	0.220	0.125
Sample size	96624	96624	96,624
Number of groups	11	11	11

Standard errors in brackets
*** p<0.01, ** p<0.05, * p<0.1

Table A2: Nodal Price 2012 (North Island)

	Dependent variable: The nodal prices in 2012 dollars ($/MWh)		
	Sample: North Island		
	(1)	(2)	(3)
VARIABLES	OLS	Panel fixed effects	A Spatial Durbin Model (SDM)
wind	-0.0451***	-0.1343***	-0.884***
	[0.003]	[0.004]	(0.0209)
hydro	-0.0038***	0.0254***	-0.262***
	[0.001]	[0.002]	(0.0133)
thermal	0.0104***	0.0417***	-0.104***
	[0.001]	[0.001]	(0.0104)
load	0.0117***	0.1005***	0.482***
	[0.001]	[0.002]	(0.0126)
Weekday	14.6164***	9.9578***	8.093***
	[0.411]	[0.399]	(1.183)
Spring	-23.8011***	-16.5951***	-18.59***
	[0.529]	[0.519]	(1.399)
Summer	4.7370***	13.8152***	23.74***
	[0.528]	[0.521]	(1.438)
Autumn	10.7031***	15.3268***	30.85***
	[0.524]	[0.507]	(1.188)
sigma2_e			23.17***
			(0.157)
Constant	66.4704***	30.5038***	/
	[0.566]	[0.808]	/
F-test	954	1687	/
R2	0.127	0.0526	0.257
Sample size	52704	52704	52,704
R2_w	/	0.204	0.258
rho	/	0.463	0.952***
			(0.000417)
Number of groups	6	6	6

Standard errors in brackets
*** p<0.01, ** p<0.05, * p<0.1

Table A3: Nodal Price 2012 (South Island)

	Dependent variable: The nodal prices in 2012 dollars ($/MWh)		
	Sample: South Island		
	(1)	(2)	(3)
VARIABLES	OLS	Panel fixed effects	A Spatial Durbin Model (SDM)
wind	0.0670***	0.3154***	1.525***
	[0.025]	[0.028]	(0.117)
hydro	-0.0080***	-0.0331***	-0.494***
	[0.001]	[0.002]	(0.0106)
load	0.0025*	0.2368***	1.900***
	[0.001]	[0.011]	(0.0481)
Weekday	10.5484***	9.5466***	9.091***
	[0.643]	[0.645]	(1.507)
Spring	-72.1965***	-68.6896***	-23.98***
	[0.824]	[0.833]	(2.320)
Summer	-4.6567***	-3.0015***	19.60***
	[0.822]	[0.820]	(1.755)
Autumn	37.1147***	37.2727***	31.46***
	[0.822]	[0.821]	(1.804)
sigma2_e			21.47***
			(0.160)
Constant	93.2779***	47.8006***	/
	[0.939]	[2.611]	/
F-test	2722	2830	/
R2	0.303	0.104	0.352
Sample size	43920	43920	43920
R2_w	/	0.311	0.353
rho	/	0.564	0.964***
			(0.000301)
Number of groups	5	5	5

Standard errors in brackets
*** p<0.01, ** p<0.05, * p<0.1

Table A4: The Spatial Fixed Effects of Wind Generation on Nodal Price 2012 (South Island by Season - A Spatial Durbin Model (SDM))

	Dependent variable: The nodal prices in 2012 dollars ($/MWh)											
	Sample: South Island by Season											
	spring			**summer**			**autumn**			**winter**		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
VARIABLES	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total
wind	0.0846***	0.315***	0.400***	-0.105**	-0.449**	-0.554**	0.876***	3.509***	4.385***	0.248***	1.014***	1.263***
	(0.0163)	(0.0656)	(0.0817)	(0.0432)	(0.175)	(0.217)	(0.0795)	(0.319)	(0.399)	(0.0511)	(0.205)	(0.256)
hydro	-0.000828	0.00124	0.000414	- 0.121***	- 0.458***	- 0.579***	- 0.0545***	- 0.158***	-0.212***	- 0.0980***	- 0.369***	-0.467***
	(0.00145)	(0.00589)	(0.00733)	(0.00277)	(0.0111)	(0.0138)	(0.0116)	(0.0466)	(0.0582)	(0.00412)	(0.0165)	(0.0207)
load	0.0961***	0.366***	0.462***	0.630***	2.253***	2.883***	0.236***	1.051***	1.286***	0.244***	0.960***	1.204***
	(0.00685)	(0.0261)	(0.0328)	(0.0169)	(0.0658)	(0.0823)	(0.0426)	(0.168)	(0.211)	(0.0116)	(0.0457)	(0.0573)
Weekday	1.068***	3.315***	4.383***	3.499***	11.01***	14.51***	1.572	5.773	7.345	0.795	2.922	3.717
	(0.221)	(0.685)	(0.906)	(0.552)	(1.734)	(2.285)	(0.962)	(3.533)	(4.495)	(0.621)	(2.282)	(2.903)
rho			0.934***			0.937***			0.978***			0.979***
			(0.00111)			(0.00102)			(0.000368)			(0.000344)
sigma2_e			6.356***			36.62***			15.66***			6.867***
			(0.0950)			(0.546)			(0.236)			(0.102)
Observations			10,920			10,920			11,040			11,040
R-squared			0.125			0.400			0.092			0.100
Number of id			5			5			5			5

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1