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

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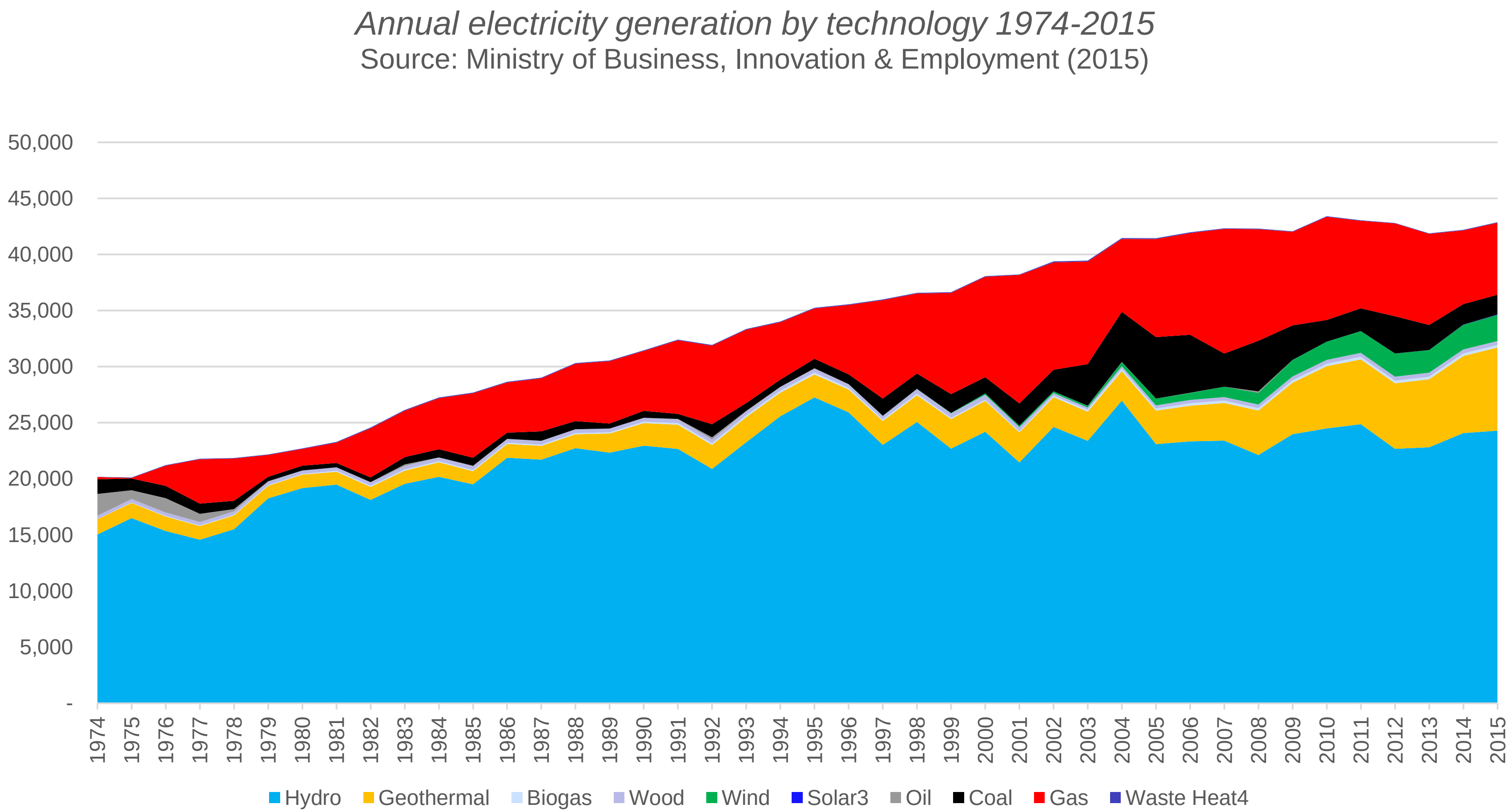
Annual electricity generation by technology 1974-2015



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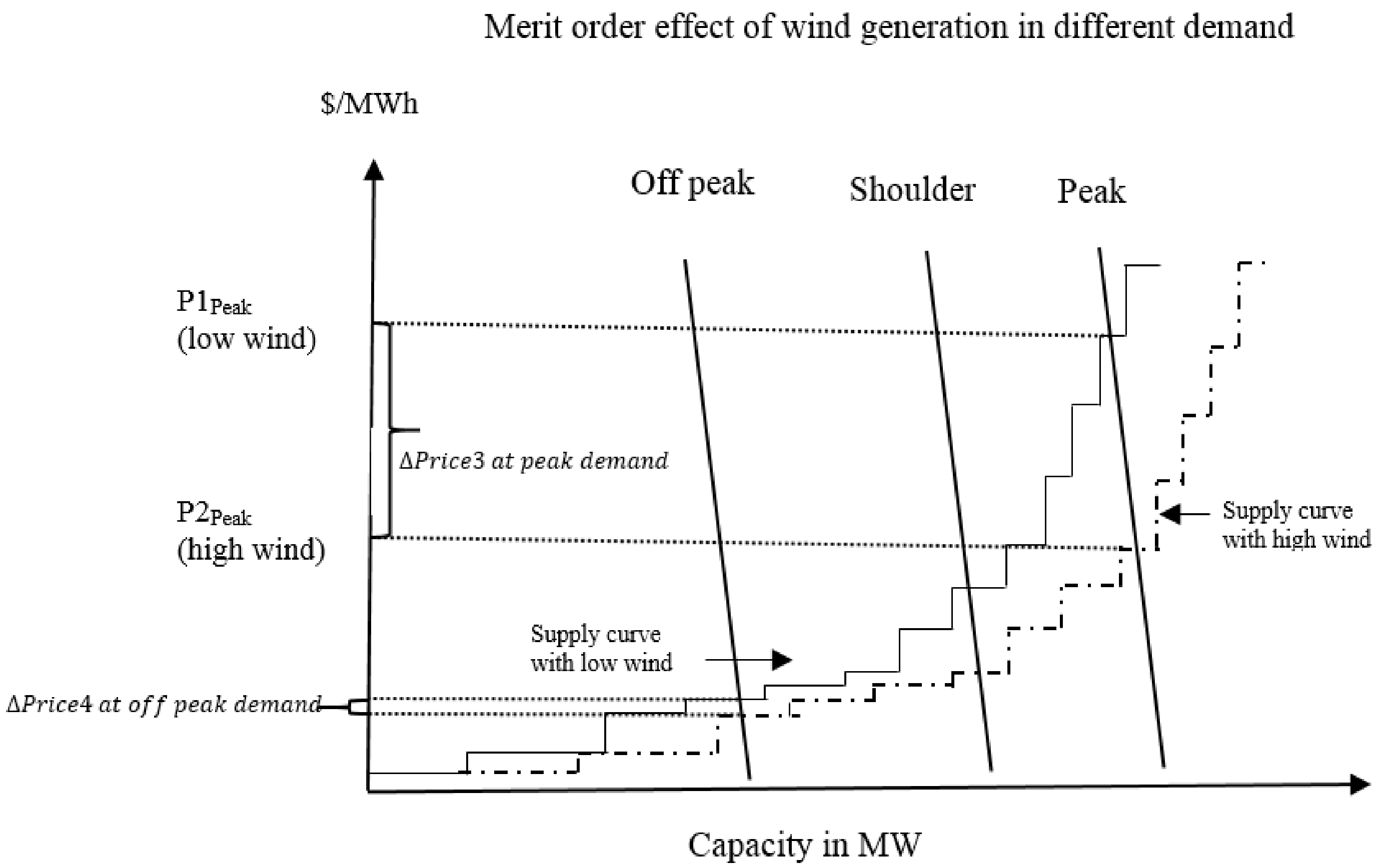
Why Should We Add More Wind Power?

- Wind power offers positive environmental and economic impacts.
- Wind contributes to the reduction of carbon emission from fossil fuel combustion and to sustaining a clean environment.
- Adding wind into existing power supply has led to lower electricity prices.

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



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Previous Literature

Authors	Country	Model	MOE Price Effect
Morthorst (2007)	West Denmark	No model	**(% Δ Price)** At >150 MW (5 – 14) At > 500 MW (12-14)
Munksgaard & Morthorst (2008)	West Denmark East Denmark	No model	**(% Δ Price)** 12 – 14 2-5
Jonsson et al. (2009)	West Denmark	Non-parametric	**(% Δ Price)** 17.5 (penetration > 4%)
Weigt (2008)	Germany	Optimisation	10 €/ MWh
Sensfuss et al. (2008)	Germany	PowerACE	7.8 €/MWh
de Miera et al. (2008)	Spain	Simulation	7.08 €/ MWh in 2005, 4.75 €/MWh in 2006 and 12.44 €/MWh in 2007

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Previous Literature

- Wind Power, Spot price, Spot-price variance
  - Woo et al. (2011) applied the method of maximum likelihood to study the four ERCOT Zonal market-price. They found a 10% increase in the installed capacity of wind generation reduced price by 2% in the non-West zones and around 9% in the West zones, but increased in the price variance of less than 1% in the non-West zones and 5% in the West zone.

  - Ketterer (2014) examined the effect of wind generation on the level and the volatility of the electricity price in Germany based on a GARCH model and found that when the wind electricity feed-in (MWh per day) increases by 1%, the price decreases 0.1% and intermittent wind power reduces the price level but increases its volatility.

Motivation

- The impact of wind power on prices has been examined in Europe, heterogeneous support for RES & the electricity markets are to varying regulated.
- In contrast, the NZ market is open, no subsidies and all supply technologies compete in electricity whole sale market. System operator dispatches on basis of least cost.
- Study the impacts of wind on prices during wet and dry seasons.
- Spatial dependence of nodal prices. Nodal price is influenced, not only by factors at the grid injection point, but also by factors at the neighbouring nodes.

Why does space matter?

- Spatial dependence

  (Spatial autocorrelation/spatial association)

  - Tobler's 'First Law of Geography': "Everything is related to everything else, but near things are more related than distant things." (Tobler, 1970)
  - In spatial datasets "dependence is present in all directions and becomes weaker as data locations become more and more dispersed" (Cressie, 1993)

  – Assumption of OLS is that observations are independent of one another

  – Are nodal prices in HAY and in BPE completely independent observations?

  – …no, so we have a violation of OLS

Data

New Zealand Electricity Authority's Centralised Dataset (CDS) 2012

•Reasons for choosing 2012 data

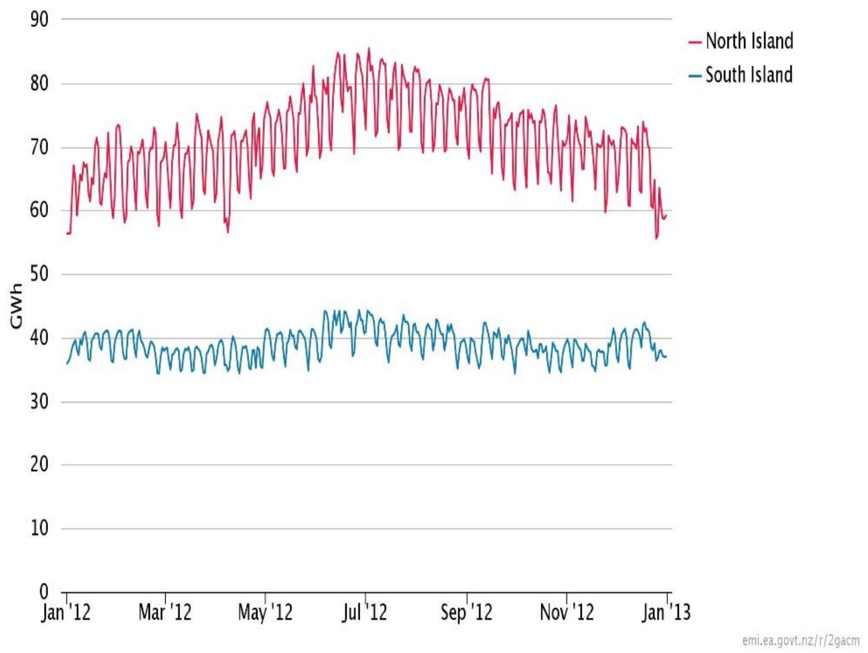
1.Estimating the effects of wind generation on nodal prices during dry and wet seasons.

2.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 was 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.

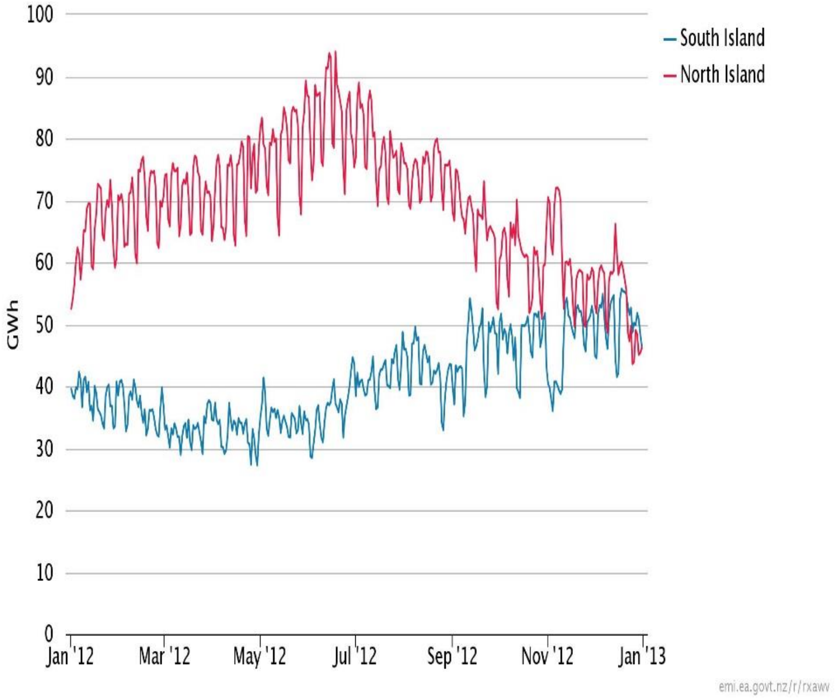
3.There was a minimal increase in installed capacity over 1993-2003. In 2011, there was a relatively large increase in installed capacity, reaching 623 MW; remaining at 623 MW until 2014 when the addition of 66 MW occurred.

Grid Demand and Supply Trends 2012 (daily average)

Grid demand trends



Grid generation trends



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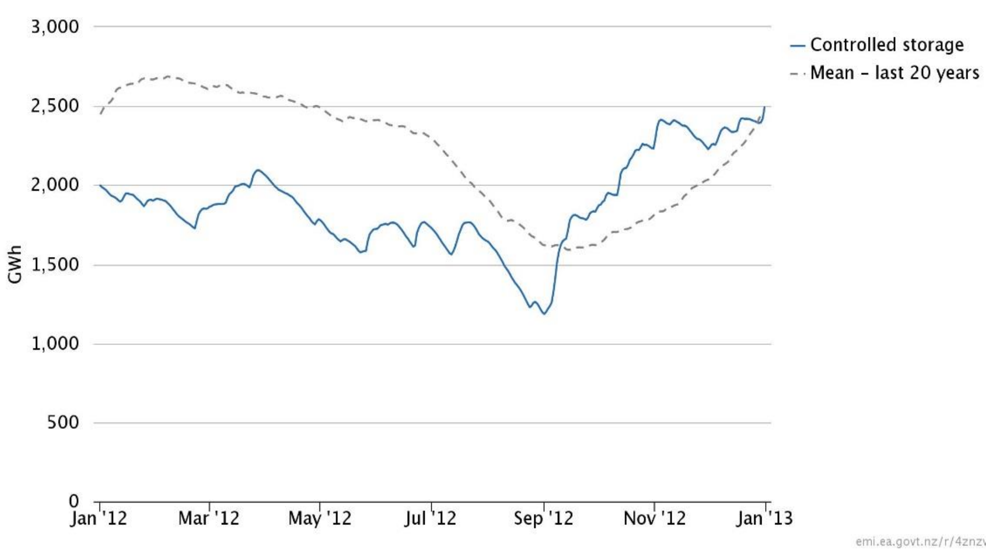
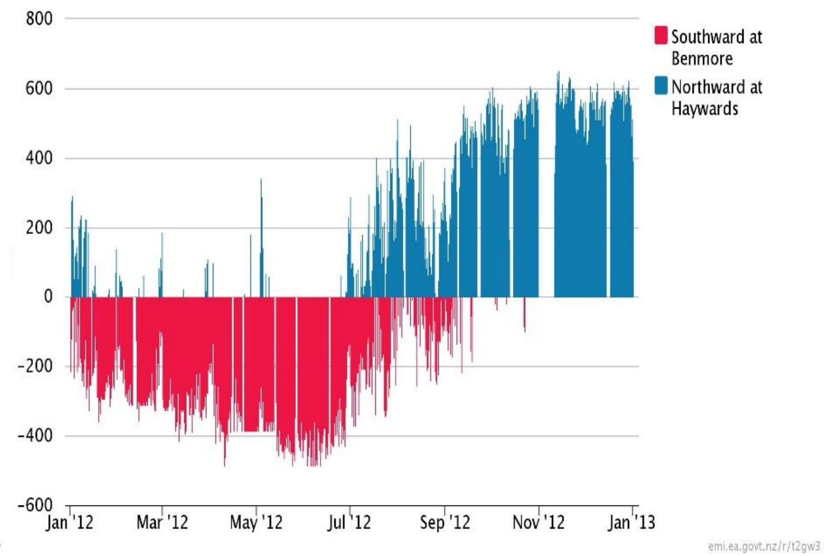
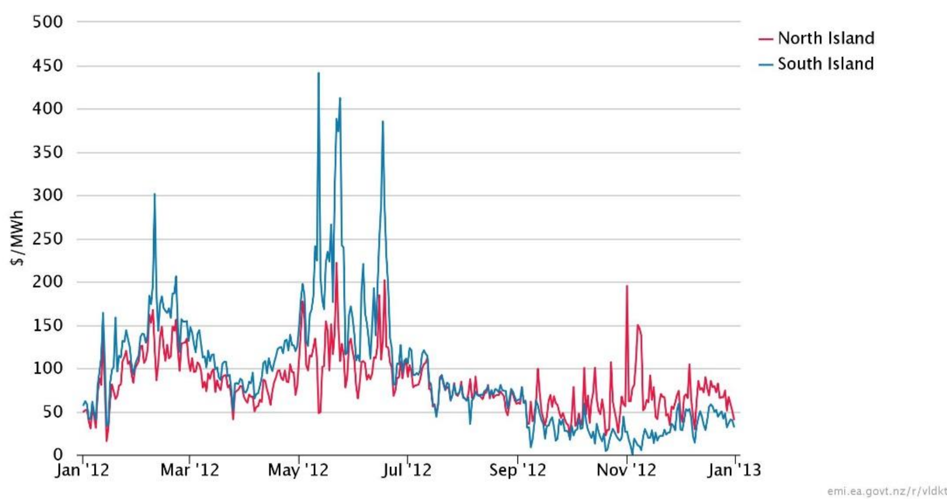
Historical Hydro Risk Curves 2010-2012



HVDC Transfer between Islands



Nodal Prices



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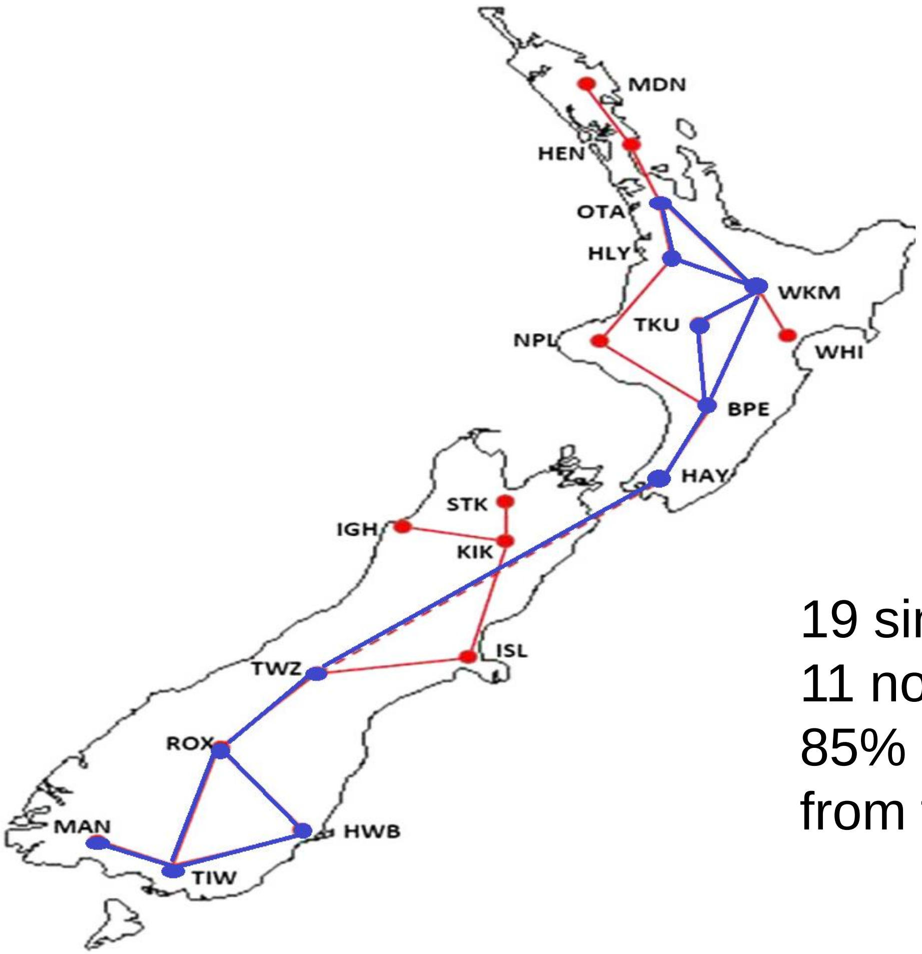
From www.emi.ea.govt.nz provided by the Electricity Authority (New Zealand)

Simplified Nodes

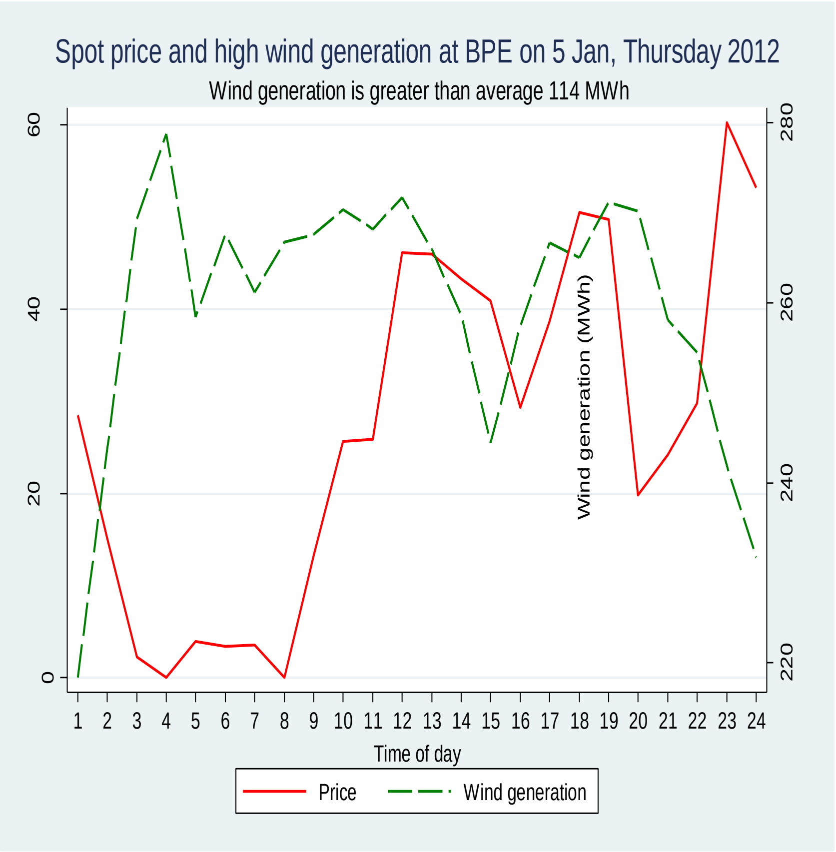


There are in excess of 240 grid injection points.

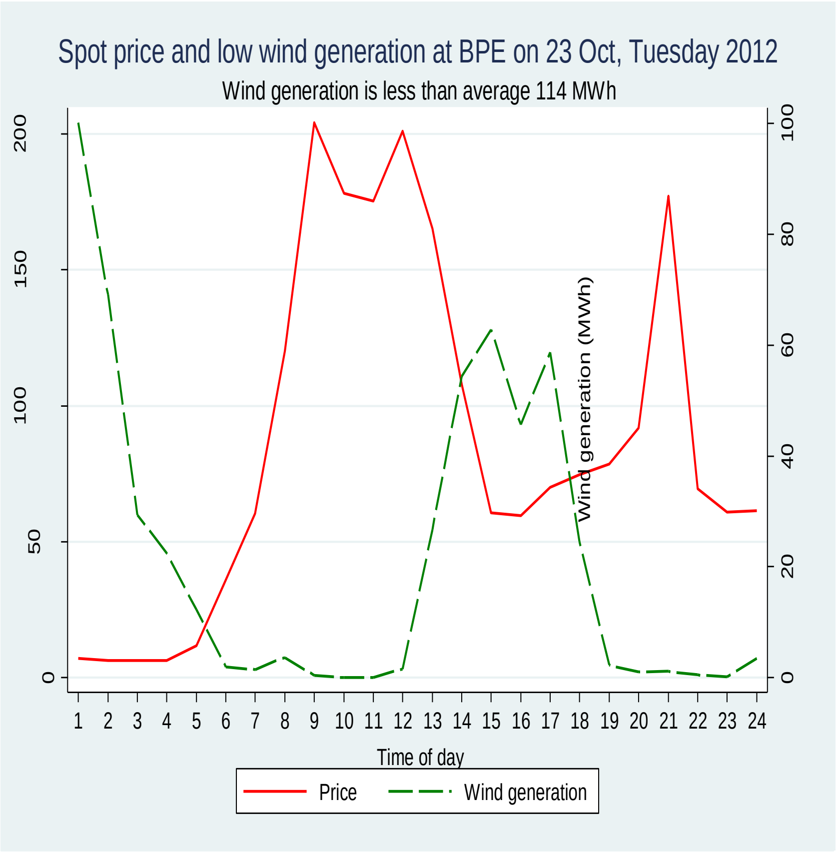
19 simplified nodes (red)
11 nodes in our study (blue)
85% of total demand was supplied from these nodes.

Negative relationship between spot prices and wind generation
(Node BPE)

(1) High wind generation



(2) Low wind generation



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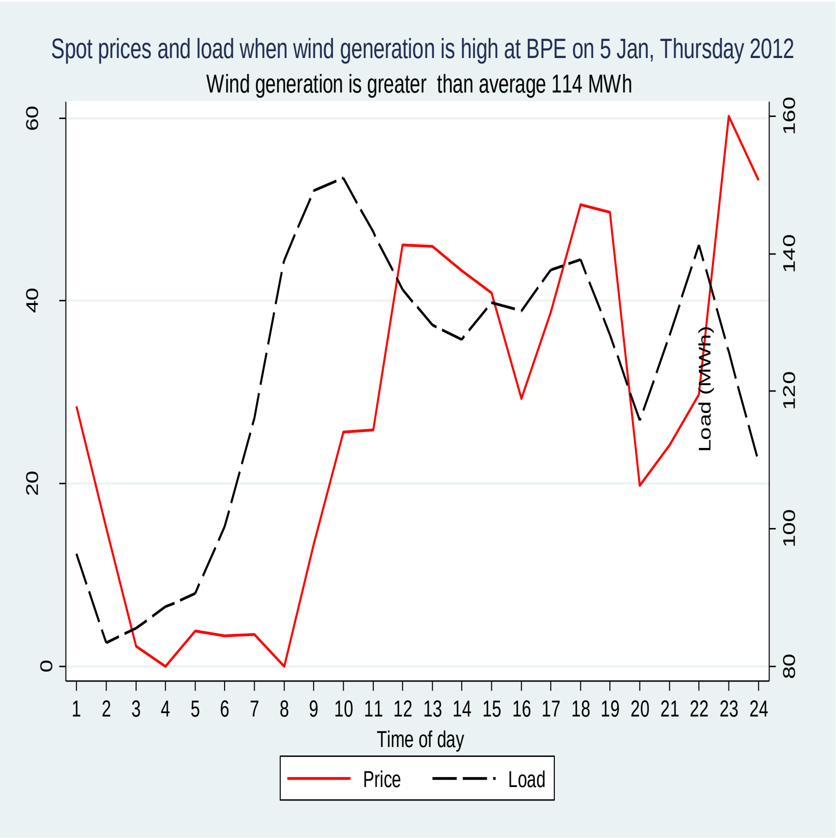
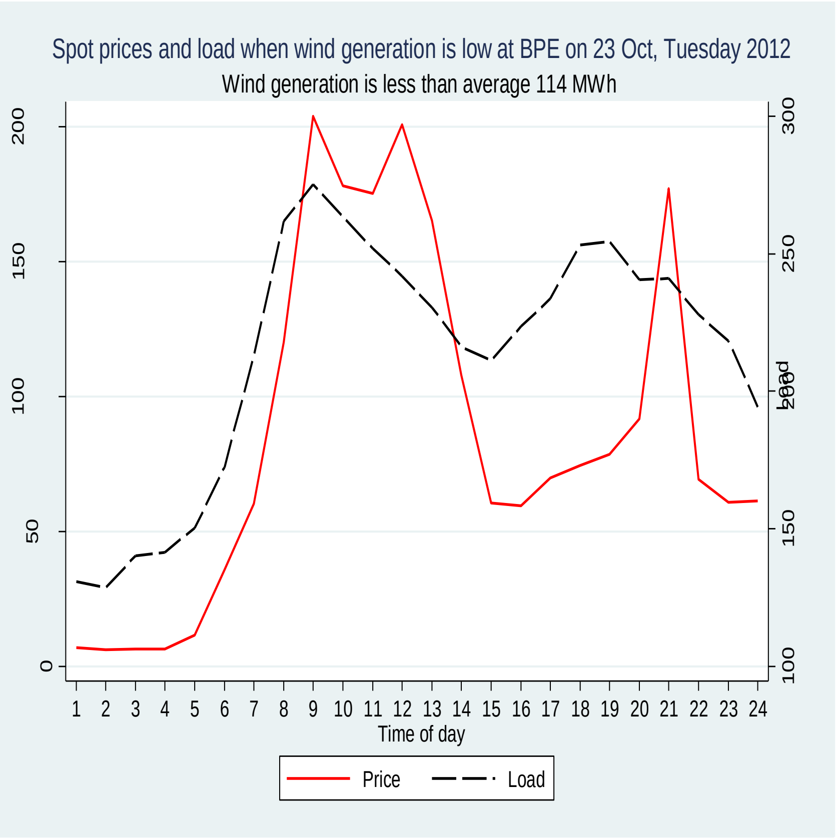
Positive relationship between spot prices and load
(Node BPE)

(1) High wind generation



(2) Low wind generation



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Spatial Econometric Model

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

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

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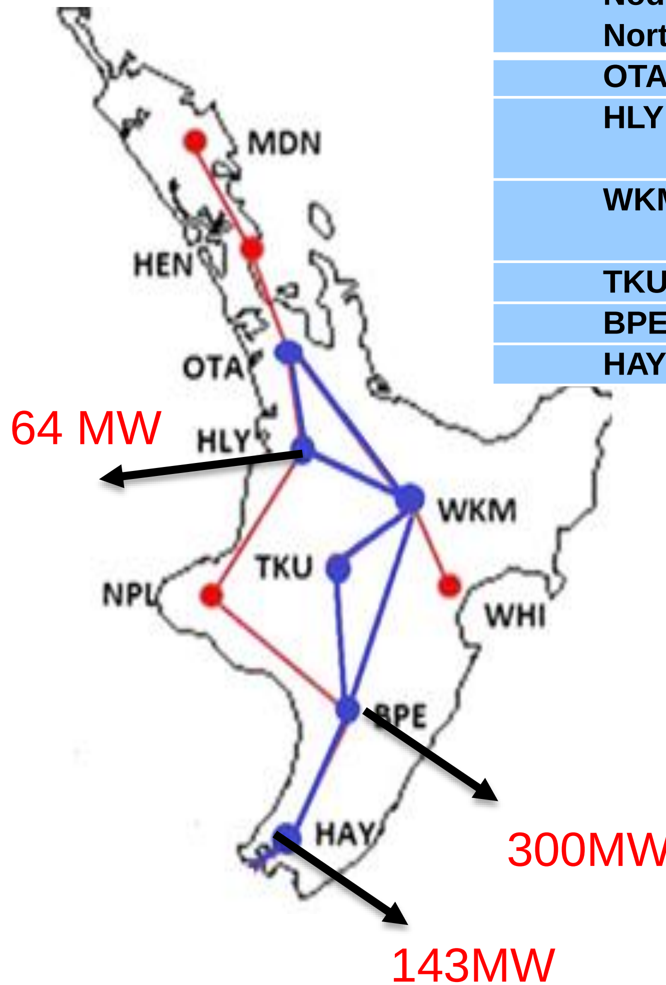
Spatial Model for North Island



Nodes in the North Island	Plant types
OTA	Thermal
HLY	Thermal, Wind
WKM	Geothermal, Hydro
TKU	Hydro
BPE	Wind
HAY	Wind

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A Spatial fixed effects Durbin Model (SDM) 2012 North Island by Season

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)
Observations			13,104			13,104			13,248			13,248

Notes: The models include hydro, thermal, load, weekday dummy variables. Full results are available upon request.

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.

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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

- The price reduction varies among seasons. It ranges from 2.25% in winter to 11.14% in spring. A reduction in nodal price is associated with increased nodal price variance.
- 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.
- Enlarging wind capacity tends to reduce the nodal prices, but also tends to increase the variance of nodal prices. This is consistent with the results of Ketterer (2014) and Woo, et al (2011).

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

Sample: North Island by Season

	spring			summer			autumn			winter		
	peak	**shoulder**	**night**	**peak**	**shoulder**	**night**	**peak**	**shoulder**	**night**	**peak**	**shoulder**	**night**
VARIABLES												
wind	-0.2172***	-0.1157***	-0.0962***	-0.1964***	-0.1912***	-0.1766***	-0.1416***	-0.1186***	-0.1437***	-0.0283**	0.0123	-0.0605***
	[0.030]	[0.010]	[0.008]	[0.013]	[0.013]	[0.012]	[0.016]	[0.011]	[0.011]	[0.013]	[0.011]	[0.008]
Observations	4368	4368	4362	4358	4351	4368	4385	4394	4415	4284	4354	4412

Notes: Based on Genesis Energy home pricing plans (https://www.genesisenergy.co.nz/understand-our-pricing-plans), we define 7am-11am and 5pm-9pm as peak periods, 11am-5pm, 9pm-11pm as shoulder periods, and 11pm-7am as night periods.

The models include hydro, thermal, load, weekday dummy variables. Full results are available upon request.

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