What Happens to Electricity Prices when the Wind and Sun Supply Half the Electricity Market?

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Abstract

Over the last six years, the electricity market in South Australia has changed remarkably. Wholesale energy prices doubled, the production from wind and solar increased to become 48% of generation in the State, the last coal-fired power station closed, and gas prices almost doubled. To understand the wholesale electricity prices we apply an econometric analysis to identify the contribution of higher gas prices, higher renewable electricity production, coal generation closure, changing demand and the entry and demise of a carbon tax. The analysis contributes to the merit order effects literature by distinguishing seasonal effects, variable rooftop solar, 30-minute prices and the effects of coal generation closure. The analysis shows that the growth in renewables is responsible for a $AUD 37/MWh reduction in 2018 prices, while coal generation is associated with a $24/MWh increase in prices from what they otherwise would have been. In addition, we find that price reductions attributable to renewables were more than three times larger than the value of their subsidies, and encouraging new renewables is likely to have a bigger impact in reducing prices than extending the life of existing coal generators.

1 Introduction

There has been a pronounced shift towards renewable energy in South Australia (SA), one of the five regional markets of the National Energy Market (NEM). In 2018 wind and solar photovoltaic (PV) accounted for 48% of electricity production, compared to 26% in 2012. This increase in renewable energy coincided with a significant rise in wholesale electricity prices from $69/MWh in 2013 financial year to $98/MWh in 2018.

In 2016, the last 520 MW coal-fired power station closed in South Australia. Some commentators (The Australian, n.d.) suggested coal generation closure and renewable generation explain higher prices while others (Leitch, n.d.) suggested renewables expansion reduced prices. The research presented in this paper seeks to apply objective methods to determine how South Australia’s wholesale price changes can be explained.

To understand the trend of renewables on energy prices we look at the international literature. In the German energy market, Paraschiv et al. (2014) found that prices were negatively correlated with the volumes of both wind and solar generation. Also in Germany, Cludius et al. (2014b) analysed hourly market data over the period from 2008 to 2012, their results showed that wind generation reduced prices on average by about 0.6 €/MWh for each percentage point increase in the wind or solar PV generation. Würzburg and Linares (2013) present an empirical analysis of renewable energy on prices in Germany and Austria and review relevant studies published before 2013. In all cases, the studies found that increasing (non-hydro) renewable generation reduced average wholesale prices. Bushnell and Novan (2018) show that wind is negatively correlated with price in California, USA, although solar generation reduces mid-day prices and increases in shoulder hour prices. Cludius et al. (2014a) and Forrest and MacGill (2013) showed that in 2013 NEM prices were negatively correlated with the volume of wind generation. All these studies consider energy markets with a far smaller percentage of renewable energy then South Australia, additionally; none of these studies considers the impact of fossil fuel closure on energy price. To understand the extremely high prices in South Australia requires additional analysis.

This paper contributes to the merit order literature by distinguishing seasonal effects, the impact of variable rooftop photovoltaic (PV) and coal closure on wholesale prices. The paper is structured as follows: Section 2 provides background to the NEM and surveys the relevant literature. Section 3 describes the model and data. Section 4 presents the results. Section 5 discusses the results, and Section 6 concludes.

2 Background

National Energy Market (NEM)

The National Electricity Market (NEM) is an interconnected power system and wholesale market that covers the large-scale production and supply of electricity in five separate markets aligned with the state boundaries of Queensland, New South Wales, Victoria, South Australia and Tasmania. The wholesale “spot” market is a five-minute energy-only market where generators bid their capacity in ten price/quantity bands. Bids are stacked in price order for each 5-minute interval with the uniform market clearing price being the lowest bid that meets the forecast demand in each region subject to transmission capacity, power system and generation operational constraints. Regional reference node prices correspond to the location of the capital cities of each state. All generators in each region receive payment for their energy supplied after adjustment for loss factors, based on the regional Settlement Period prices calculated as the average of the six five-minute “Trading Period” prices in the region in which that generator is located. The five NEM regions are connected through six regional interconnectors. When interconnectors are unconstrained, regional prices converge, forming a single or multi-regional market. When interconnector constraints bind, the NEM regional markets separate and the market clearing price in each region is then determined by generation in each region.

2. 1 The South Australian electricity market

South Australia is the South Eastern State of Australia with a total net generation quantity of 13.8TWh in FY2017/18 and 48% of generation from rooftop PV solar and wind generation. Figure 1 (a) shows the breakdown of the main sources of South Australian energy production, by technology, between 2013 and 2018. Noteworthy over this period was a complete removal of coal generation, a 60% growth in wind production, 125% growth in solar production and a 39% reduction in interconnector imports. In 2016, South Australia closed its last coal power station (520 MW, Northern Coal Power Station). In 2017, the interconnected region of Victoria closed one large coal power station (1600MW, Hazelwood Power Station). Small-scale solar generation (less than 100kW per system) in South Australia far exceeds the large-scale solar generation, which in 2018 was 1,030 GWh and 3.8 GWh respectively. In addition, imports from Victoria increased in 2017, perhaps in part attributable to the closure of the coal-fired Northern Power Station. In 2018, interconnector imports decreased to the lowest levels in recent history, perhaps attributable in part to the closure of the Hazelwood Power Station in Victoria in March 2017, continued expansion of wind and solar production and significantly higher output from combined cycle gas turbine generation in South Australia, shown by the expansion of the green bar. Figure 1 (b) shows the average spot price where a significant increase in average spot prices after FY2014/15 can be observed.

Figure 1 a) South Australia generation, b) South Australia average spot price for years ending 30 June

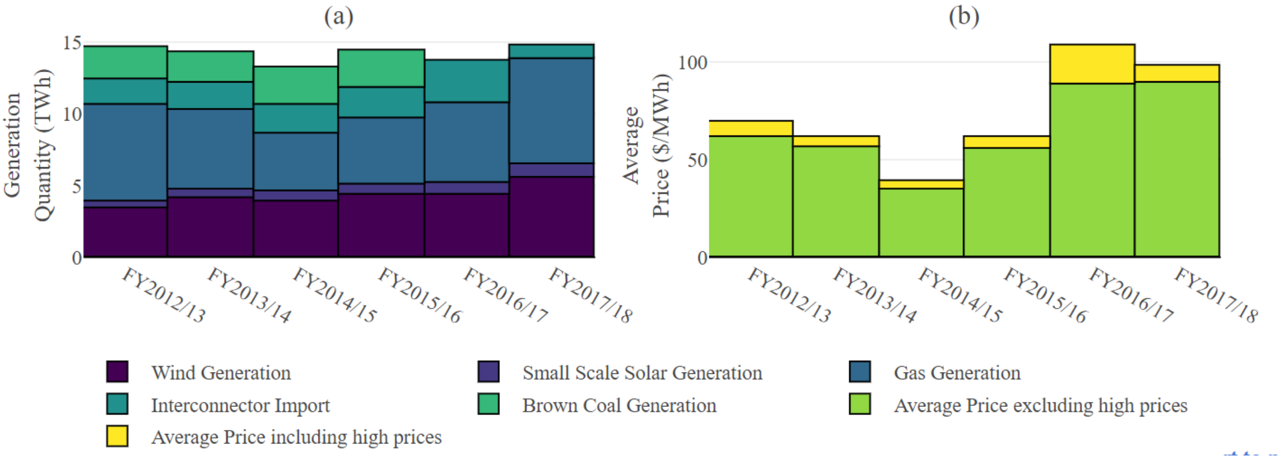
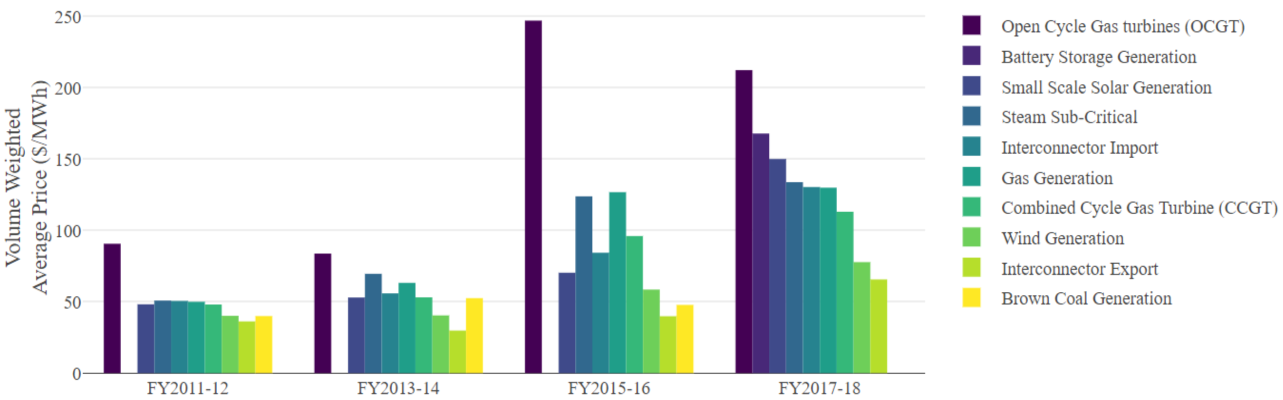


Figure 2 shows the volume weighted average price (VWAP) received for the various production types in South Australia. The VWAP is calculated as the total revenue on the SA spot price for each production type in each financial year divided by the total generation in that financial year. The VWAP has been increasing since 2012. Production from Open Cycle Gas Turbines (OCGT) received the highest prices followed by steam sub-critical steam generation. The Hornsdale Power Reserve (at the time of installation in October 2017 it was the world's largest battery) received similar prices as the OCGT plant, though other storage revenue was received from ancillary services. VWAP was low for interconnector exports as expected (exports occur when generation surpluses in Australia force production to find other markets).

Figure 2. Financial year volume weighted average price (VWAP) by generation type



Interestingly and contrary to expectations, the volume-weighted average prices received by different production technologies shows that despite the large increase in the amount of renewable production relative to dispatchable production, the prices received by renewable generation has nonetheless not declined.

2.2 Literature

Merit order effect studies are either empirical studies, using historical data in econometric models of price, or simulation models which may use either real, ex-post data, or hypothetical data, or a mixture of both (Würzburg and Linares, 2013). Initially simulation studies were most often used because actual performance data was limited. More recently, as renewable energy support programs have matured and the contribution of renewable energy to electricity supply has grown, empirical studies have dominated. However, simulation studies can be used for counter-factual analysis to produce insights not available from empirical studies. Simulation studies can also be used to forecast future outcomes. This type of analysis has so far dominated in emission reduction and renewable energy policy discussion in Australia. In introducing their analysis of the combined electricity markets of Germany and Austria, Würzburg and Linares (2013) note that only one of the eight studies of the German market cited in their review uses the empirical approach.

Würzburg and Linares (2013) analysed the impact of renewable energy over two years from mid-2010 to mid-2012. It uses average daily values in a multivariate regression model in which the explanatory variables are demand, supply by wind and solar generators, gas price, and exports and imports from and to the German-Austrian system. More recent empirical studies vary in their choice of econometric approach, explanatory variables and in whether they use hourly or daily data, but most present their results in the form of a reduction in average wholesale price per additional unit of renewable energy supplied. Ketterer (2014) analyses the German system using daily data over the period 2006 to 2012 using a similar model and finds a smaller price reduction than Würzburg and Linares (2013), of approximately 1.5% per one percentage point increase in the wind share of total supply. This was likely due to the smaller percentage of renewable energy over this period compared to (Würzburg and Linares, 2013).

Paraschiv et al. (2014) analysed the German energy market, over the period 2010 to 2012, using prices on three separate one hour periods on every day during the period: hour 3 (overnight), hour 12 (noon peak) and hour 18 (evening peak). The model used as its explanatory variables, demand, fuel prices (coal, oil, gas), available generation capacity, wind generation, solar PV generation, and several lagged variables related to past prices introduced to allow learning over time. The authors found that, as might be expected, market prices are positively correlated with the prices of coal, gas and oil. In another analysis of the German system, Cludius et al. (2014b) analysed hourly data over the period from 2008 to 2012 to estimate the merit order effect of wind and PV generation in each of the years, they use independent valuables demand, wind generation, seasonal trends and weekends, however, they do not model the impact of rooftop solar on demand.

For Australia, a study by Forrest and MacGill (2013) analysed the relationship between wind generation and NEM spot prices, using thirty-minute data for two years from March 2009 to February 2011. The analysis was undertaken at the regional level within the NEM, for South Australia and Victoria, the two regions with the highest volumes of wind generation. When applied to the average wholesale price in each region over the two years, it was found that wind generation reduced the wholesale price in South Australia by $8.05/MWh and in Victoria by $2.73/MWh. At that time, shares of wind generation, averaged over the period, were 19% in South Australia and only 1.9% in Victoria. When expressed relative to shares of generation, therefore, the estimated price reductions become $0.43/MWh per one percentage point share of wind generation in South Australia and $1.42/MWh in Victoria. Although the authors do not make the point, these results are consistent with the expectation of a diminishing marginal merit order effect as the wind share of total generation increases. For the NEM as a whole, Cludius et al. (2014b) also using thirty-minute data, found that the average NEM price (volume weighted across the five NEM regions) decreased by $2.30/MWh in the year 2011-12 and by $3.29/MWh in the year 2012-13 as a result of the wind generation merit order effect. The wind shares of total NEM generation in those years were respectively 4.3% and 4.6%. These merit order price reductions were, therefore, $0.54 and $0.71 per wind share percentage point. These merit order effect estimates can't be meaningfully expressed as proportions of the total wholesale price, because the introduction of a price on carbon in July 2012 caused wholesale prices to more than double. None of the studies reviewed considers the impact of coal closure on wholesale energy price.

3 Econometric Model Formulation

Our analysis is based on half-hourly linear regressions using the functional form specified in Equation (1). This model formulation is particularly influenced by the approach in (Bushnell and Novan, 2018) and is also consistent with econometric analyses in (Cludius et al., 2014b; Würzburg and Linares, 2013). The model allows us to understand the impact of renewable generation on wholesale prices in half-hourly intervals. We solve the regression for Equation (1) using an ordinary least squares regression for each half-hour period of the day, h (where $h \in \{0, 0.5, 1, \ldots, 23.5\}$) to provide the $\beta_{h,s}$ regression coefficients. Our work extends the work of (Bushnell and Novan, 2018) by solving the model for each season S (where $S \in \{Summer, Autumn, Winter, Spring\}$. This provides additional insight into the seasonal trends in the wholesale market. The data used in the model covered half-hourly intervals during 1st July 2012 to 30th June 2018.

$$P_{h,s} = \beta^{0}_{h,m,s} + \beta^{w}_{h,s} \cdot W_{h,s} + \beta^{PV}_{h,s} \cdot PV_{h,s} + \beta^{g}_{h,s} \cdot G_{d,s} + \beta^{D}_{h,s} \cdot D_{h,s} + \beta^{c}_{h,s} \cdot C_{h,s} + \beta^{CP}_{h,s} \cdot CP_{h,s} + \varepsilon_{h,s} \quad (1)$$

Where, $P_{h,s}$, is the half-hourly spot in a season (S) and is measured in \$/MWh, $W_{h,s}$ is the half-hourly gross wind generation in MWh, $PV_{h,s}$ is the half-hourly gross rooftop PV generation in South Australia in MWh, $D_{h,s}$ is the half-hourly state demand plus exports and before rooftop solar in MWh, $G_{d,s}$ is the daily gas spot price in \$/GJ, $C_{h,s}$ is the available coal capacity in South Australia, which was a relatively constant value equal to the aggregation of 520 MW until the Northern Power Station closure on 6th June 2016, and 460 MW of interconnector capacity until the 1st of July 2017 to access the 1600 MW Victorian Hazelwood Power Station through the Haywood interconnector. $\cdot\, CP_{h,s}$ is a binary variable used to indicate time periods where the carbon price was active in Australia. $\beta^{0}_{h,m,s}$ is used to account for monthly seasonal fixed effects. $\beta^{g}_{h,s}$ is the gas price coefficient and describes the \$/MWh change in wholesale price for a \$1/GJ change in gas spot price. $\beta^{w}_{h,s}$ is the wind generation coefficient and describes the \$/MWh change in wholesale prices per MWh change in wind generation dispatch. $\beta^{PV}_{h,s}$ is the solar coefficient and describes the \$/MWh change in wholesale prices per MWh change in solar generation dispatched. $\beta^{D}_{h,s}$ is the demand coefficient measured in \$/MWh per MWh change in hourly demand. $\beta^{c}_{h,s}$ describes the fixed affect in \$/MWh when coal generation was available in South Australia and $\beta^{CP}_{h,s}$ is the price impact when the carbon price was active.

We do not include a lagged output in the model as shown in (Cludius et al., 2014a; Forrest and MacGill, 2013), and instead follow the recommendation of (Bushnell and Novan, 2018) and assume that only the current level of renewable output and other variables influences the price.

We assume that wind and PV generation are exogenous, influenced by vastly different weather systems and seasonality and are not correlated given by a Pearson Product Moment (PPM) coefficient of 0.05. Demand is driven by temperature and time of the day and exogenous to all model variables including wind and PV generation. For demand and PV, we observed a PPM value of 0.15, and for demand and wind, we observed a PPM of 0.06; showing both are not correlated with demand. We see some level of correlation between coal closure and gas price, given by a PPM of 0.4, though the decision to close the Northern and Hazelwood Power Stations were exogenous to gas prices. We observe a PPM value of approximately 0.1 for all other variables. As in numerous other studies (Bushnell and Novan, 2018; Cludius et al., 2014b; Würzburg and Linares, 2013) we conclude all variables in the system are causally independent and not collinear.

3.1 Data

The wholesale price used in the model is the half-hourly, South Australian spot price. The half-hourly wind generation data, interconnector export, operational demand and spot price was sourced from NEMReview (“NEMreview,” n.d.), which accesses the data from AEMO. Adelaide hub, Short Term Trading Market (STTM) (AEMO, n.d.) gas price data was sourced from AEMO. The demand used by the model is the sum of the Operational Demand, total exports on the interconnectors plus the gross PV production described above.

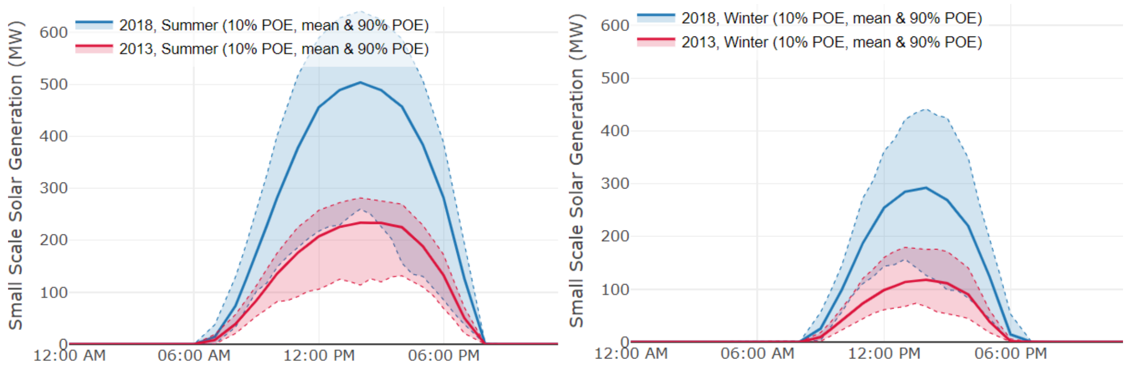
The dataset excluded time instances when price spikes above \$1000/MWh. This is because very high prices are exogenous to our model in Equation (1) and are commonly caused by unplanned outages, tripped interconnectors, market intervention and the exercise of market power.

3.1.1 Rooftop solar modelling

In Australia, the production from small-scale behind the meter solar PV generators is not centrally measured. To estimate the impact that rooftop solar has had on wholesale energy prices it was necessary to estimate half-hourly rooftop solar production. We did this by using the Bureau of Meteorology (BoM) Gridded Solar Irradiance dataset (BOM, n.d.) and the Australian Clean Energy Regulator (CER), Postcode Data for Small-Scale Installations dataset. The BoM dataset provided the hourly irradiance profiles for each postcode from June 2012 to July 2018. The Python Package, PVLib (PVLib, n.d.), simulated the performance of photovoltaic energy systems to determine the AC PV generation output for 35 typical PV orientations for each postcode. An average of the 35 profiles provided the average hourly generation profile for each postcode. The clean energy regulator dataset (CER, n.d.) provided the monthly installed capacity for each postcode back to June 2012. The hourly generation output for each postcode is calculated by multiplying the cumulative sum of postcode PV capacity by the normalised hourly PV profile for that postcode. A total sum of all postcode PV generation profiles gave the South Australian rooftop solar generation profile. The hourly data was upsampled to half-hourly using a linear interpolation between known points.

Figure 3 shows the simulated South Australian FY2012/13 and FY2017/18 daily average PV generation for summer and winter. Due to less solar irradiance in winter and suboptimal rooftop solar orientation, the solar generation for winter is less than summer. The variation in cloud cover throughout the season explains the wide POE range.

Figure 3. Summer and winter average daily small scale solar supply including the 10% and 90% probability of exceedance (POE) range.



4 Results

We describe here the main results from the model focusing on the differences between summer and winter. The model achieved an average in sample R^2 score of 0.59 tested on data from July 2012 to June 2018 limiting the model to fit to prices below $1000/MWh. The model accurately estimates average spot prices. For example in 2018 the average annual price predicted by the model was $89.9 per MWh, compared to the actual average of $90 per MWh, in both cases excluding Settlement Period prices greater than $1000/MWh. The coefficients on the key variables of interest in the regression (coal closure, gas prices, wind and solar production) are statistically significant at 1 percent in almost all the 192 half hourly regressions (48 half-hour intervals for four seasons).

Figure 4 shows the summer and winter wind generation coefficients and the 95% confidence interval. It shows that increasing the average wind generation by 100 MW would reduce the wholesale price by around $8.6/MWh throughout the year. The precise coefficient varies around the day, with summer price impacts most significant (but also most variable) around 3-6pm. Variability here is measured as the size of the interval that the model estimates, with 95% confidence, that the true value is likely to lie within. The wider variability in summer between 3 pm and 9 pm can be attributed to the higher volatility of wholesale prices in summer.

Figure 4. Summer and winter wind generation coefficients.

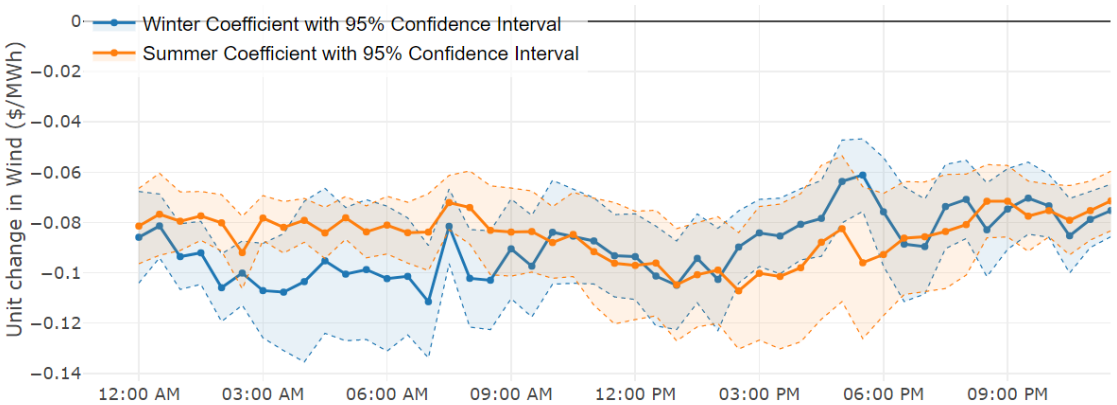


Figure 5 shows the solar generation coefficients. It shows that a 100 MW increase in average PV production would reduce prices by around $11/MWh in summer and around $31/MWh in winter. Of course in winter, solar generation is lower than in summer (as shown in Figure 5) and so though the *marginal* impact is higher in winter, the total impact is lower. The narrow confidence interval in summer during most of the day reflects the consistency of sunshine in summer months. Similarly, the wide confidence intervals at the start and end of the day reflect the variability of sunshine in these hours combined with the higher volatility in spot prices at these times. Solar slightly increases prices in the late afternoon in summer, as shown in Figure 5. This might be argued to be consistent with (Bushnell and Novan, 2018), observations in California, that solar had driven out more efficient generation in the middle of the day thus creating a demand for the less efficient generation to meet the evening peak when solar is not available.

Figure 5. Summer and winter seasonal solar generation coefficients.

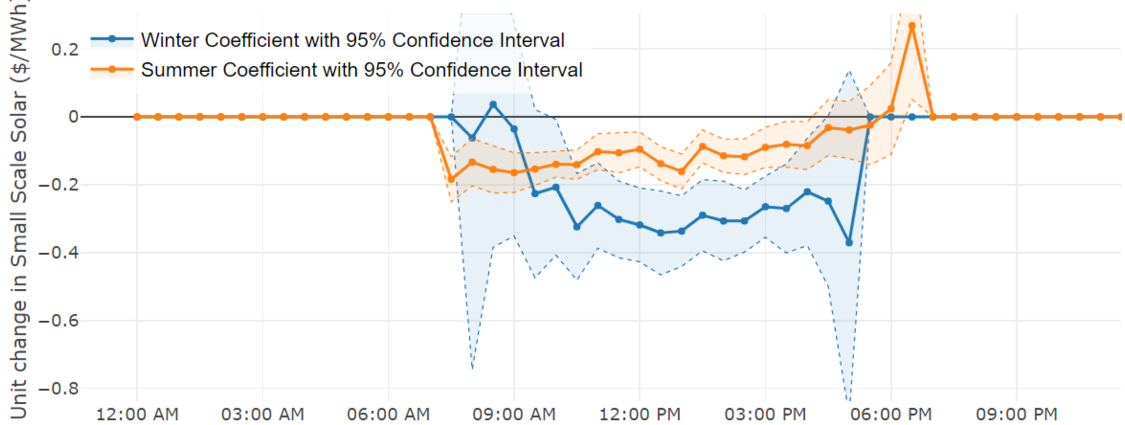


Figure 6 shows the demand coefficients and the 95% confidence interval. The demand coefficient values for winter are higher before 9 am and drop after 8:30 am. This can be attributed to the winter morning peak being met, at the margin, by less efficient OCGT (Open Cycle Gas Turbine) and SUBCRIT (Subcritical gas thermal at Torrens Island) gas generation. The subcritical generation in South Australia converts gas into electricity at the rate of about 13 GJ per MWh, the OCGT at a slightly lower rate and the CCGT at the rate of around 7.5 GJ per MWh. In summer, a smaller increase in OCGT and SUBCRIT occurs during the morning. During the summer daytime, demand coefficient values exceed the winter values, and this can be attributed to the increased daytime dispatch of the inefficient SUBCRIT and OCGT compared to the daytime in winter. The wide 95% confidence interval in the morning in winter can be attributed to high variation in demand, as shown in Figure 6.

Figure 6. Summer and winter seasonal demand coefficients

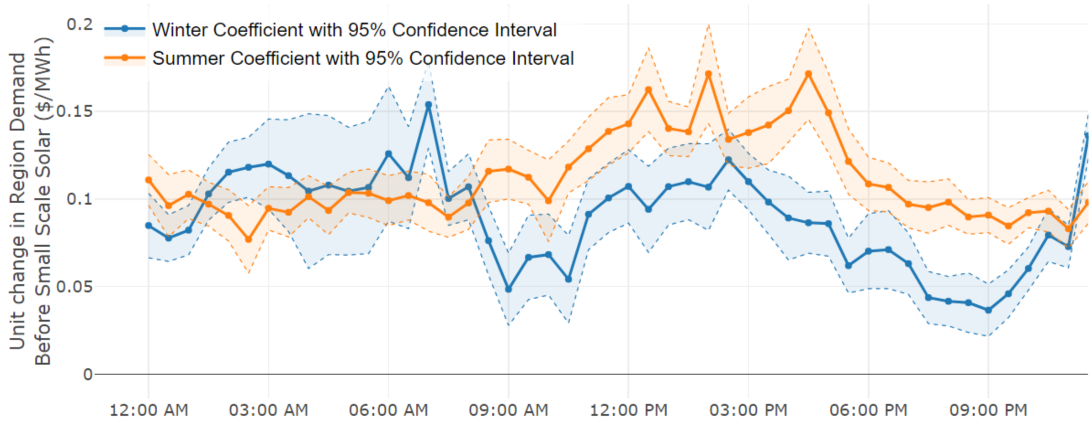


Figure 7 shows the impact of daily gas prices on hourly wholesale price. The gas price coefficient represents the change in wholesale price due to a $1/GJ increase in daily gas prices. A $3.20/GJ change in gas price, which occurred between 2012 and 2018 would cause an average increase in the wholesale price of $14.10/MWh in summer and $26.25/MWh in winter. The gas price has a major impact on wholesale electricity prices because the gas generation is usually at the margin. The gas price has a higher impact on wholesale prices when less efficient gas generation - OCGT and SUBCRIT - is at the margin. This is evident for summer and winter, where gas prices influence electricity prices more during hours of higher OCGT and SUBCRIT dispatch following the same trend as Figure 7, with a lower OCGT and SUBCRIT dispatch in summer. This explains the higher coefficients in the morning and evening in winter, and throughout the day in summer.

Figure 7. Summer and winter seasonal gas price coefficients

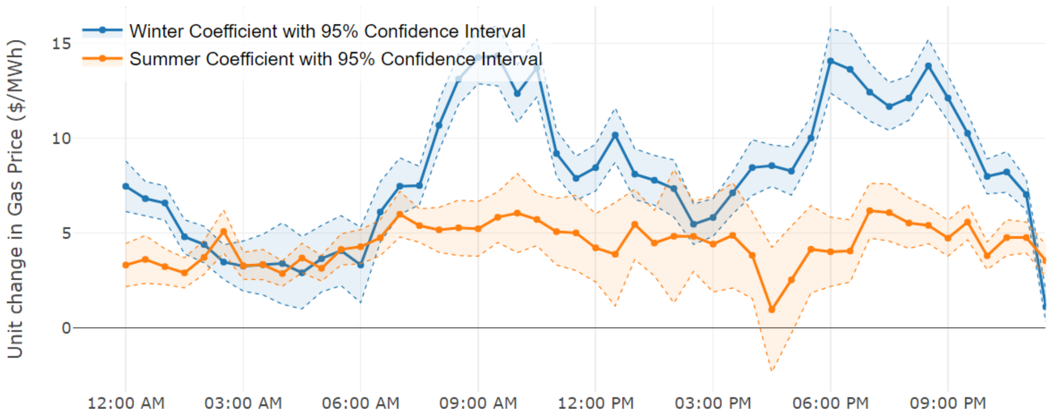
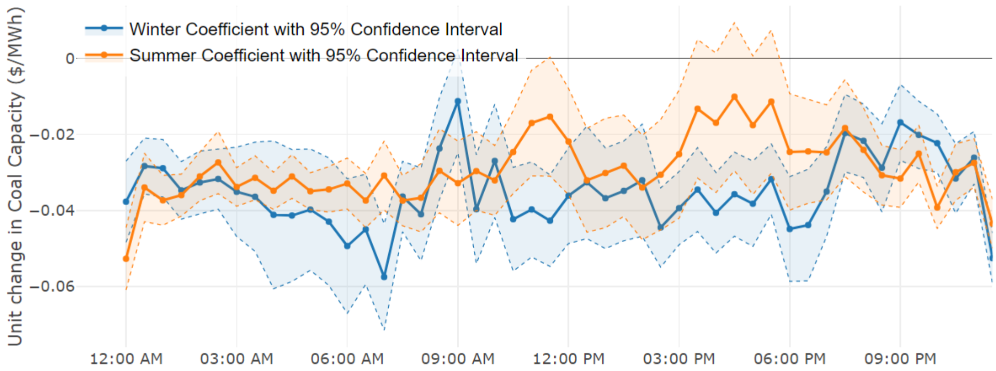


Figure 8 shows the impact on price from losing one MW of coal capacity. Applying the model shows that the closure of the 520 MW Northern coal-fired power station in 2016 resulted in prices that are $13.2/MWh higher than they otherwise would be. The closure of the 1,600 MW Hazlewood coal-fired power station in Victoria in 2017 resulted in prices in South Australia that are $10.7/MWh higher than they otherwise would be. This assumes that the capacity of the 460MW capacity of the Haywood interconnector was available for dispatch to South Australia. Considering all four seasons, the average effect of both

Northern and Hazelwood generation closure has been to increase prices in South Australia by $24/MWh from what they otherwise would have been.

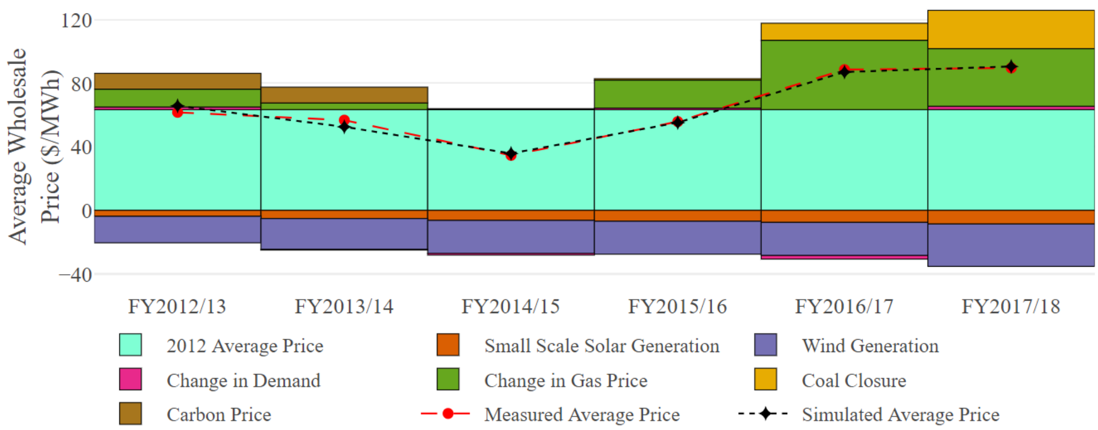
Figure 8. Coal capacity coefficient



4.1 Decomposing the spot price in South Australia

To quantify the change in wholesale electricity prices attributable to gas prices, the carbon tax, wind generation, solar generation and demand, we used the regression model to decompose the half-hourly SA spot price into each component. Figure 9 shows the decomposed average wholesale price from 2012/13 to 2017/18. The change in SA's high gas prices since 2011/12 explained an increase of $36 per MWh. The 1,000 GWh of solar and 5,550 GWh of wind generation reduced prices by $9/MWh and $27/MWh respectively. Adding these together our model predicts 2018 average annual prices of $89.9 per MWh, compared to the actual average of $90 per MWh, in both cases excluding Settlement Period prices greater than $1000/MWh; similar accuracy in forecasting average annual prices is achieved for all years. The model predicts that the carbon price, active during 2013 and 2014, was responsible for a $10/MWh increase in average prices. The figure shows that wind and solar pulled average wholesale prices down, while South Australia's high gas prices and the loss of coal generation pulled them up.

Figure 9. Decomposition of the 2013-2018 average wholesale price in South Australia



We also used the model to explain why the average prices increased from $60 per MWh in 2012/13 to $90 per MWh in 2017/18. We find that the closure of the coal generators is associated with an average increase of $24 per MWh, as discussed above, and the increase in gas prices from $5.5/GJ (in 2013) to $8.5/GJ (in 2018) increased average prices by $25 per MWh and the increased output from wind and solar brought them down by $15/MWh. The net of these changes - $34 per MWh - explains the change in the spot price from 2012/13 to 2017/18. Without the reductions achieved by more wind and solar productions, SA prices would have been far higher leaving other factors unchanged.

5 Discussion

The impact of renewables in reducing prices in South Australia is higher than reported in some of the studies in other countries. This is explained by much higher gas prices and much less efficient gas generation in South Australia than in other countries. In South Australia wind and solar production is therefore typically displacing much more expensive production than it is in other countries and so unsurprisingly has had a bigger impact in reducing wholesale prices. Another notable feature is the impact of gas price increases in explaining wholesale price increases. In the converse of the situation in North America where gas price reductions have had a bigger impact than renewables in reducing wholesale electricity prices, over the period from 2013 to 2018, higher South Australian gas prices have had a bigger impact in raising electricity prices than renewables have had in lowering them. Furthermore, with the loss of 520 MW of coal generation capacity in 2016, the interconnector flows changed so that imports have roughly halved and exports have risen from negligible levels to be higher than imports in the winter of 2018 relative to winter 2013. However, daily interconnector flows are far more variable in 2018 than 2013, as expected given the higher renewable production. Similarly, while South Australian gas generation in the winter of 2018 is almost exactly the same as the winter of 2013 and gas generation in the summer of 2018 is a bit higher than summer of 2013, in both summer and winter of 2018, gas generation is considerably more variable than it was in 2013. This increased variability is again consistent with the higher variable renewable production over this period.

This analysis is able to assess whether the wholesale price reductions attributable to wind and solar exceed the additional cost of the subsidies provided through Small Scale Technology Certificates and Large Scale Generation Certificates, that are recovered from consumers. From 2013 to 2018, the Small Scale Technology Percentage has averaged 12.6%, and Renewable Power Percentage has averaged 12.9%. Assuming an average price of Small Scale Technology Certificates of $40 and Large Scale Technology Certificates of $45, this implies the average cost of renewable subsidies over this period has been $11/MWh. By comparison, our analysis concludes that wind and solar generation reduced prices by $21/MWh in 2013 and $37/MWh in 2018. The higher reductions in 2018 are to be expected taking into account higher renewable generation and higher priced gas production that was displaced by the renewable generation in 2018 compared to 2013. Evidently, the price reductions exceed the subsidies associated with the wind and solar – at a rate of more than three to one in 2018.

Finally, the analysis here can inform the response to the question of the contest between coal generation and renewables in reducing South Australian wholesale prices. An alternative to subsidies to expand renewable generation would have been to subsidise the refurbishment of the Northern Power Station and the depleted Leigh Creek coal mine. In addition to subsidies to revive the plant and mine, the expansion of renewable generation would need to have been constrained in order to preserve the market for the protected coal generator. Subsidising coal-based production would also require additional public funds to procure greenhouse gas emission reductions that are foregone if the coal generator continues to operate. The size of the subsidy needed to refurbish the generating plant and mine is not known. Foregone emission reductions can be priced using the delivered price in the Australian Government's "Direct Action" program (around than $14/tonnes CO2-e) (AFR, n.d.). Considering the emission intensity of the Northern Power Station (around 1.4 tonnes CO2-e per MWh), this translates into additional emission abatement costs of $19.6 per MWh of Northern production.

It might also be argued that in order to protect the Northern coal power station production from being displaced by zero marginal cost renewables, it is necessary to constrain the expansion of renewable generation. To price this, we take the average price reduction associated with renewables from the model ($38/MWh for 6,600 GWh of wind and solar production) and assume that production from Northern displaces 2,330 GWh of renewable production (this is the average level of Northern's production for the last four years of its operation). On this basis, foregone price reductions associated with foregone renewable production of $13/MWh arise.

The size of the subsidy needed to refurbish the generating plant and mine is not known. We can value the foregone emission reductions using the price of emissions achieved in the Australian Government's "Direct Action" program (typically around $14/tonnes CO2-e), and the emission intensity of the Northern Power Station (around 1.4 tonnes CO2-e per MWh). This translates into an emission price of $19.6/MWh for the foregone emission reduction associated with keeping the Northern power station in operation rather than replacing its production with zero emission renewables.

So, even before factoring in the subsidy to refurbish the plant and mine, continued operation of the Northern power station would have meant prices $32.6/MWh higher than they otherwise would be (foregone $13/MWh reduction from more renewables plus $19.6/MWh additional emission abatement cost). However, the model shows that closure of the Northern plant leads to prices that are $13/MWh higher than they otherwise would (i.e. continued operation of the Northern plant, would have avoided a $13/MWh increase). In other words, even before factoring in the subsidy needed to revive the plant and mine, electricity consumers would have been worse off if the Northern power station's life had been extended.

In addition, assuming the average price reduction associated with renewables from the model ($37/MWh for 6,600 GWh in 2018), continued production from the Northern Power Station at the average level of its last four years (2,330 GWh per year) would have meant foregone price reductions associated with foregone renewable production of $13.5/MWh. In other words, even before factoring in the subsidy needed to revive the plant and mine, electricity consumers would have been worse off to the extent that consumers are charged for the foregone emission reductions if the Northern Power Station's life had been extended.

6 Conclusion

Our analysis of South Australia, consistent with the studies in Australia and internationally, concludes that renewable generation reduced wholesale prices. Gas prices are by far the most significant factor explaining South Australia's high wholesale prices. Over the period from 2012 to 2018, increases in wind and solar production have reduced wholesale prices more than coal closure in South Australia has raised them. Coal generation closure raised prices, but these were offset by reductions from the renewable generation that replaced it. Even leaving aside the subsidies that would have been needed to extend the life of the Northern generating plant and Leigh Creek coalmine, electricity consumers would have been worse off to the extent that they would be required to bear the cost of foregone emission reductions.

The analysis shows renewable generation reduced prices in 2018 more than three times as much as they cost to subsidise. This analysis therefore leaves little doubt that in South Australia, leaving other factors unchanged, promoting renewable production rather than protecting coal generators is the route to lower wholesale and retail electricity prices.

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