Does renewable electricity generation reduce electricity prices?

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Table of contents

Index of Tables

Index of Figures

Executive summary

In Australia the contribution of "base load" coal-fired electricity generation compared to variable renewable generation in explaining high wholesale and retail prices is actively discussed. This report is motivated by the desire to contribute evidence to this discussion.

The report surveys the literature on the relationship between the growth in renewable generation and wholesale electricity prices. It also examines the evidence on the relationship between final (retail) electricity prices and renewable electricity generation in those countries that have high retail prices, and that have enthusiastically promoted renewable generation.

The report also analyses wholesale "spot" electricity market prices in South Australia to uncover the relative impact of renewables, coal generation closure and gas prices. South Australia is a relevant case study considering the closure of significant amounts of coal generation in South Australia and neighbouring Victoria, the introduction and subsequent withdrawal of a tax on greenhouse gas emissions, large increases in gas prices and the increase in distributed and grid-scale renewable electricity generation in South Australia.

Literature on the impact of renewables on wholesale prices

There is a rich literature on the impact of renewables on wholesale electricity prices in electricity markets in Germany, Spain, Denmark, the Netherlands, Ireland, Israel, the UK, Austria, Italy and in the different regional markets in the USA. None of the studies conclude that renewable generation caused wholesale prices to increase. One study concluded that renewables had no impact on wholesale prices and the others report price reductions of varying size. In Australia two studies other than this study (the most recent using data to June 2013) suggested renewables had reduced prices in the National Electricity Market.

Few studies assess the "net" impact of renewables (i.e. the extent to which wholesale price reductions attributable to renewables were offset by the cost of the renewables' subsidy). Those studies that did examine this tended to conclude that the benefit of price reductions was more than offset by the cost of the subsidy, at least to household customers. In some countries, large industrial consumers enjoy some level of exemption from renewables subsidies and so the growth of renewable production has been clearly beneficial to them.

International retail price comparison

The international retail price comparison, though inevitably a study of high-level averages, produced understandable and consistent observations. In all the European countries with very high electricity prices and rapid growth in renewable production, wholesale prices have fallen as renewable production has increased. In most countries renewable subsidies charged to households rose as renewable generation grew but in some cases (not most) wholesale prices declined as much as or more than charges for renewables subsidies rose. Nevertheless the countries with the highest prices – Germany and Denmark – pay by far the highest taxes unrelated to renewable subsidy. In all countries, taxes unrelated to renewables are higher than the charge for the subsidy of renewables.

In Australia, some have attributed the rise in electricity costs to the increasing share of renewables in the fuel mix. Comparisons show (see Figure E1) that prices in Australia reflect relatively high charges to produce and transport electricity to consumers. Moreover, prices in Australia are heavily impacted by renewables subsidies (which are lower in Australia than in the European countries) or taxes (which again are typically much lower in Australia than in the European countries).

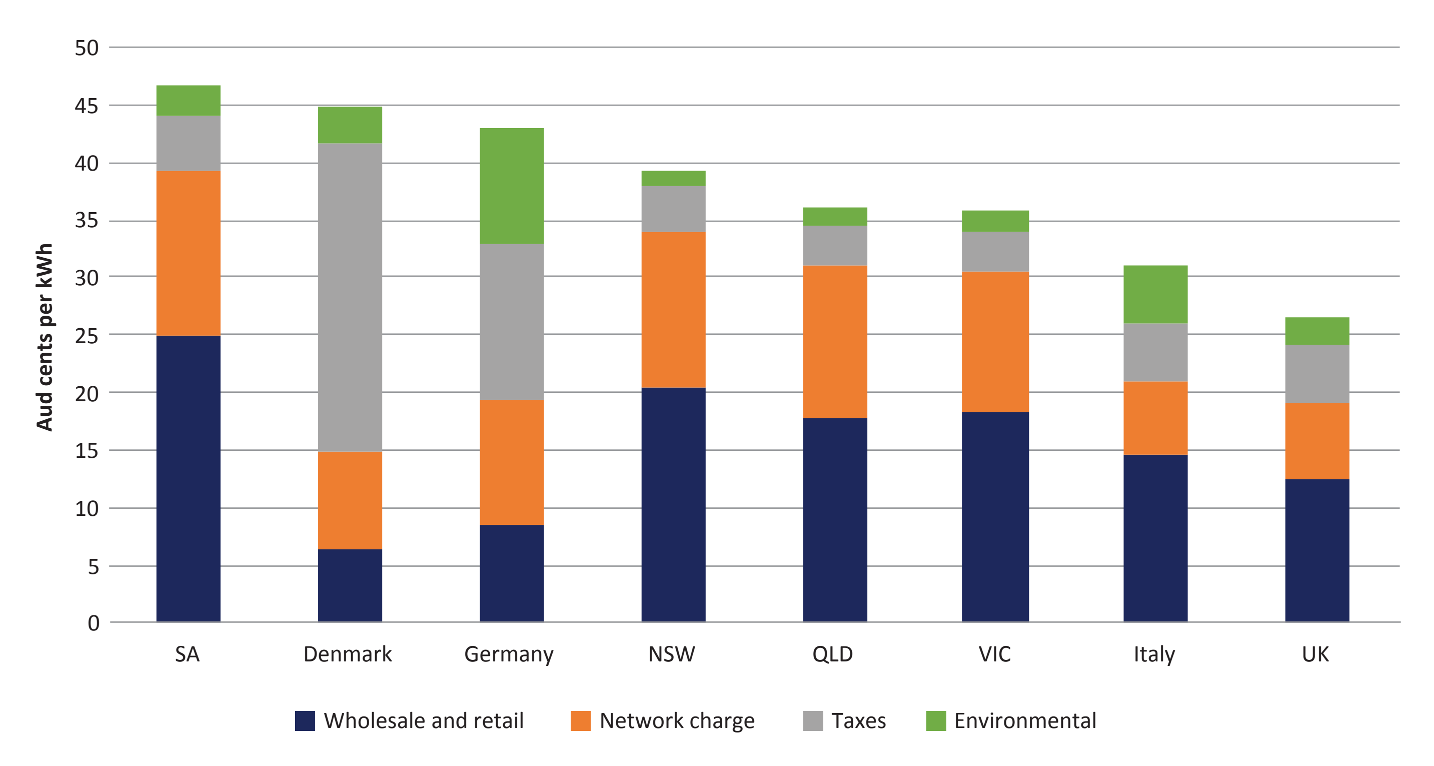

Figure E1: Australia versus Europe household electricity prices[1]

South Australia case study

Our analysis finds that renewable generation reduces wholesale prices in South Australia. We estimate that expanding wind generation will reduce wholesale prices at the rate of around $0.09/MWh, per one MWh of additional wind generation. For solar – almost all of which has so far been on household roofs – we estimate the wholesale price reduction at the rate of around $0.26/MWh, per one MWh of additional solar production. In summer, additional solar has a smaller impact on wholesale prices of around $0.11/MWh per one MWh of additional solar production compared to $0.31/MWh in winter. The lower impact in summer can be explained by the typically higher level of gas generation (and hence less efficient and thus more expensive gas production at the margin) in winter than in summer.

The closure of 520 MW of coal generation capacity at the Northern Power Station in South Australia in 2016 and the closure of 1,600 MW of coal generation at the Hazelwood Power Station in Victoria in 2017 raised wholesale prices in South Australia by $23 per MWh from what they otherwise would be. This is more than offset by price reductions attributable to renewable generation ($38 per MWh in 2018). Compared to 2013 (when Northern was still producing) by 2018 imports on the interconnectors with Victoria had roughly halved and exports had risen from negligible levels in 2013 to be higher than imports, in the winter of 2018. However daily interconnector flows, production from gas generation and spot prices

1. It is important to note that in Figure E2, the relative contribution of wind and solar is an average that reflects the rate ($/MWh per one MWh of production) at which renewables reduce spot prices multiplied by the quantity (MWh) of their production.

are more variable in 2018 than 2013. This is expected considering the expansion of renewable generation. The large share of production from gas thermal generation has exacerbated the impact of higher gas prices, particularly during peak periods.

Figure E2 shows the model's decomposition of the 2018 average wholesale (spot) price in South Australia. It shows the price of meeting South Australian demand (and exports) in 2018, excluding the impacts associated with gas prices and renewables, and then the incremental impact associated with each of these. Renewables brought wholesale prices down by $38 per MWh in 2018 (of which $10/MWh from 1,110 GWh of distributed solar generation and $28/MWh from 5,500 GWh of wind generation).

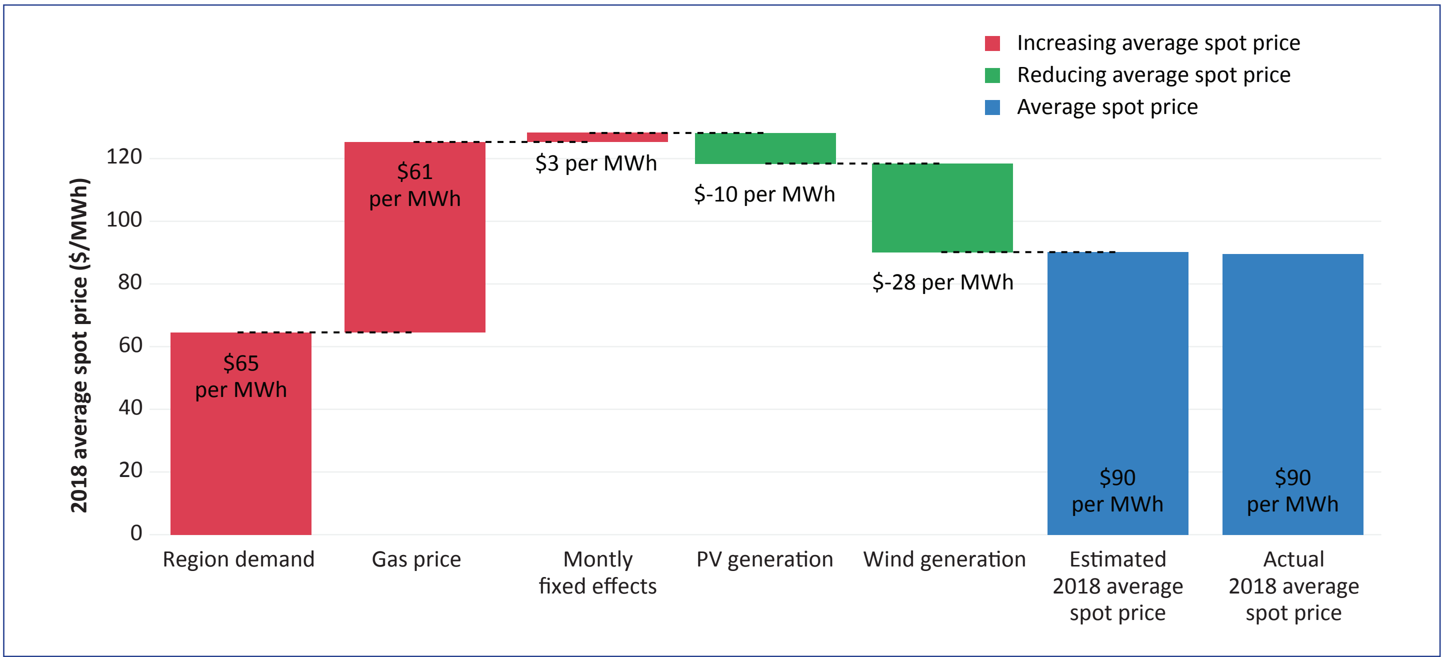

Figure E2: Decomposing the 2018 South Australia wholesale price

Finally, this analysis is able to respond to the question of whether prices would have been lower if the life of the Northern Power Station had been extended. Deferring closure would have required public subsidy to refurbish the generating plant and Leigh Creek coal mine, and to replace the foregone greenhouse emission reductions that closure would have delivered. While closure would raise prices, this needs to be set against the foregone of price reductions associated with the renewable production that would have otherwise replaced it.

We do not know the amount of subsidy that would have been needed to extend the life of the generating plant and coal mine. We estimate the cost of foregone greenhouse gas abatement at $19.6/MWh and the foregone price reductions associated with foregone renewable production at $13.5/MWh. This more than offsets the estimate of the price increases associated with the plant's closure ($13/MWh). To the extent that electricity customers would be required to bear the additional cost of the foregone emission reductions, they would be worse off even before taking into account the subsidy needed to keep the plant operating. Considering that, by comparison, the subsidy of renewables delivered price reductions more than three times the cost of the subsidy, there is little room for doubt that directing subsidy to renewables rather the prolonging the life of the Northern Power Station is the route to lower electricity prices.

The same forces that have shaped rapid changes in the power system in South Australia are now increasingly felt in the rest of Australia. A forthcoming Technical Working Paper will describe in greater detail the econometric techniques used in this study and will analyse the current and likely future impact on wholesale prices of coal closure and renewable generation expansion in other parts of Australia.

1 Introduction

There is active debate in Australia about electricity prices and how they are influenced by increasing amounts of renewable electricity generation and coal generation closure. Some contend higher renewable generation is associated with higher electricity prices and so the solution to higher prices is to return to greater coal-fired electricity generation.[2] Others suggest renewables reduce prices and so the solution to higher prices is to expand renewable generation.[3]

Price comparisons are complex not least because customer markets are diverse (e.g. households versus businesses, big households versus small households, engaged customers versus disengaged customers). In addition, prices can be measured in many different ways (e.g. wholesale versus retail, before or after taxes) and the electricity value chain is long and complex. It is difficult also to objectively untangle the various factors that affect wholesale and retail prices. Recognising these difficulties, this report responds to four questions:

1. Has the rise of renewable generation caused household prices to rise or fall in other countries that have pursued renewable electricity generation?
2. Do renewable subsidies explain Australia's high electricity prices?
3. Does the increase in renewable electricity generation in South Australia explain why their prices are higher than in the rest of Australia?
4. Are customers better off if subsidies are directed to extending the life of existing coal fired generating plants or promoting greater renewable generation?

To answer these questions we examine first the academic literature on the impact of renewable generation on prices in Australia and in other countries. We then examine household electricity prices (and their constituent elements) in those countries in Europe (Denmark, Germany, Italy and Great Britain) with the highest prices and where renewable generation has grown rapidly. We then compare their prices to the prices paid by households in Australia's contestable retail markets. Finally, we develop an econometric analysis of the South Australian data to identify how South Australia's prices have been affected by renewables and coal generation closure.

2. See for example https://www.theaustralian.com.au/news/inquirer/its-a-universal-truth-renewables-mean-higher-costs/news-story/c2c3d834d2127034e3c4c85452dd6384
3. See for example https://reneweconomy.com.au/does-more-renewable-energy-mean-higher-prices-10310/

2 Literature review

This section reviews the international and Australian literature on the relationship between the production of electricity from large-scale centrally dispatched renewable generation, on wholesale and retail electricity prices. The section begins with a brief discussion of the main concepts, followed by a review of the European, North American and Australian literature.

Electricity production from centrally dispatched generators in interconnected electricity markets – such as the National Electricity Market (NEM) – is determined through a calculation that seeks to dispatch the cheapest available generators subject to physical limitations including transmission bottle-necks, the operating limits of the power stations and the need to ensure that the power system is stable and reliable. Generators can influence the likelihood that they are dispatched by offering their production to the market at a cheaper price than their competitors. Renewable generators have an advantage in this competition relative to non-renewable generators since they have negligible variable operating costs.[4] For this reason, when renewable generators are available to produce they typically displace more expensive non-renewable generators. Depending on the shape of the supply curve at the time, this can reduce the clearing price of electricity in wholesale spot markets. This dynamic is often referred to as the "merit order effect". The extent of the merit order effect has attracted interest since policies to support investment in variable renewable energy (VRE) were introduced over the last 30 years.

"Merit order effect" studies are either empirical, using past data to specify econometric models of price, or simulation models which may use either real, ex post data, or hypothetical data, or a mixture of both Würzburg et al. (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 VRE 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.

2.1 European literature

Würzburg et al. (2013) present an empirical analysis of VRE on prices in Germany and Austria and they review relevant studies published before 2013. The majority of the simulation and empirical studies they reviewed are for the electricity systems of Germany and Spain, but the review also includes two studies of Denmark and one each of Ireland, the Netherlands and Nordpool in Scandinavia.

In all cases, the studies found that increasing (non-hydro) renewable generation reduced average wholesale prices. To compare studies, the authors converted all results to a price (€/MWh) per one percent increase in the wind share of generation in the market. They found price reductions of between 0.5 €/MWh, for Nordpool, and 1.6 €/MWh, in one of the Spanish studies.

Würzburg et al. (2013) also list a number of studies that do not precisely quantify the price reduction effect. Nevertheless all of these – which cover the UK, Australia, Israel and the US state of New Jersey - conclude that increasing wind generation reduces average wholesale prices.

In introducing their own analysis of the combined electricity markets of Germany and Austria, Würzburg et al. note that only one of the eight studies of the German market cited in their review uses the empirical approach. Their analysis covers a two year period 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.

4. Appendix A summarises the costs characteristics of the various generation sources in the NEM in the year to August 2018.

The overall conclusion of the analysis is that the wholesale price decreases by about 2% for each additional GW per hour of wind and solar generation supplied. Based on annual average electricity supplied in the German-Austrian market, we estimate that this is equivalent to a 1.5% decrease in price per one percentage point increase in the volume of combined wind and solar generation supplied.

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 VRE supplied.

Ketterer (2014) analyses the German system using daily data over the period 2006 to 2012, and finds a smaller price reduction (than Würzburg et al), of approximately 1.5% per one percentage point increase in the wind share of total supply.

Paraschiv et al. (2014) analysed the German system, 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 explanatory variables in their model include 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 would be expected, market prices are positively correlated with the prices of coal, gas and oil.

They also found that prices were negatively correlated with the volumes of both wind and solar generation supplied. The modelling approach does not allow the impact of any of the variables on price, in €/MWh, to be quantified. However in an important addition to earlier studies, they conclude that variable renewable generation reduces prices overall, not just at times when VRE is supplying. Put another way, they conclude that any increases in prices that may occur at times with little or no wind and solar supply, compared to the counter factual of a system with no wind or solar generation, are not sufficient to offset the price reductions occurring when wind and/or solar are supplying.

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 from 2010 to 2012. Over these three years, wind generation increased from 7.7% to 10.8% of total supply, while solar PV generation increased from 2.0% to 5.6%. Additional wind generation reduced prices on average by between 0.54 and 0.57 €/MWh for each percentage point increase in the total share of wind generation, while the corresponding effect for solar PV is 0.5 to 0.6 €/MWh for each 1% increase. The average wholesale price in the German market over the period 2010 to 2015 was around 45 €/MWh.

A recent study of the German market by Kyritsis et al. (2017) examines daily data from 2010 to 2015, and divides the 2007 days into intervals based on the shares of wind and solar in total generation. Similar to Cludius et al. (2014), the authors find that additional wind generation reduces prices by about 0.6 €/MWh for each percentage point increase in the wind share of supply, while additional solar PV reduces prices by about 1.0 €/MWh for each percentage point increase in share of supply. Moreover, these rates of price reduction are roughly uniform across a wide range of market shares – up to 55% for wind and 21% for solar PV.

In other countries Clò et al. (2015) analyse wholesale electricity prices in the Italian market from 2005, when wind and solar PV each supplied about 0.8% of total generation, to 2013, when their respective shares had reached 5% and 10%. The authors used hourly data and their model used total load, gas price, wind generation and solar generation as explanatory variables (gas is the dominant non-VRE source of generation in Italy, accounting for 51% of generation in 2017). They found that over the last three years covered by their analysis, when both wind and solar generation increased very rapidly, wind generation reduced wholesale prices by between 1.6% and 2.8% on average over the year, per one percentage point increase in the wind share of total generation, while solar generation reduced prices by between 1.6% and 2.3%. The percentage price reductions were lower in 2013, when the annual average price was 60 €/MWh, than in 2011 and 2012, when the price averaged 72 €/MWh.

Ireland has for some years had a relatively high share of wind in its total generation mix, and it continues to increase, reaching 22% in 2016, with gas supplying most of the remainder (Sustainable Energy Authority of Ireland, 2018). Denny et al. (2017) report the results of an interesting study they made of the Ireland electricity supply system in 2009, when the wind share of generation was 12%. Using hourly data and total load, wind generation, the prices of gas, coal and oil, and the carbon price as explanatory variables, the calculated effect of wind generation is to reduce the marginal energy price in the Irish market by 3.3% per one percentage point increase in supply of wind generation. This figure is much higher than the results described above from other countries but in the Irish market, generators also receive what are called uplift payments, capacity payments and constraint payments. The paper explains that marginal energy payments account for only 55% of total payments to generators. Adjusting for this factor reduces the estimated wind merit order effect to 1.8% per percentage point increase in wind, which is in the same range as the estimates for Germany and Italy.

A distinctive feature of the paper by Denny et al. is that it also describes and reports on results produced by use of a simulation model of the Irish wholesale market system, with all generators explicitly modelled, using the same input data for the same year, 2009. The advantage of the simulation approach is that it can be used to understand the counterfactual – what prices would have been if there were no VRE generation, with all consumption being supplied by other generators in the system. The difference between total system cost with (actual) wind, and the cost with zero wind generation, is taken as the total system cost saving resulting from the wind generation. The saving calculated by this means was about 25% higher than the saving calculated by the empirical approach. The authors suggest that the main reason for the difference is that the simulation model assumes perfect day-ahead forecasts for both demand for electricity and available wind generation.

This literature review has confined itself to a relatively narrow focus on the direct merit order effect of increasing VRE generation on prices in competitive wholesale markets for electricity. Many other studies, not cited here, examine other direct effects, including effects at different levels of total load and at different times of day, and the generally accepted effect of increasing the variability or volatility of prices, all in the context of an underlying overall effect of decreasing average price levels. These effects are very important for any consideration of possible changes to market design, and when considering the optimal mix of generation types in an electricity supply system transitioning towards higher shares of VRE generation.

Overall social costs of renewables policies

The overall social cost of policies to support the growth of VRE generation is explicitly addressed in some of the studies of Germany, Spain, and Italy cited above. For Italy, Clo et al. (2015) compare the consumer cost savings through the merit order effect with the cost of measures to support investment in VRE. As in Australia, these costs are recovered in full through retail electricity prices. They find that, over the study period 2009 to 2013, the cost to consumers of supporting solar generation was almost twice what consumers saved through lower wholesale prices. For wind generation, on the other hand, savings were about 25% higher than costs. However, since solar generation was larger than wind generation, the introduction of VRE into the Italian electricity system imposed a net cost on electricity consumers, at least up to 2013.

For Spain, Gelabert et al. (2011) found that up to 2010, the cost to consumers of the feed in tariff support measures considerably outweighed the savings realised through the merit order effect. However, they observe that the net cost to consumers increased over the period from 2005 to 2010, as the surcharge to cover feed in tariff costs increased while the merit order effect per MWh of additional VRE generation decreased. Their data show unequivocally that the increased surcharge was caused by the strong growth in solar generation, which received a much higher feed in tariff than other VRE sources. Comparison with the later findings of Clo et al. (2015) suggests that a smaller merit order effect from solar, compared with wind, may also have contributed.

Paraschiv et al. (2014) reach a similar conclusion regarding net costs to consumers for Germany, though they do not show their actual cost calculations. They also make the point that this conclusion does not apply to energy intensive industries, which are better off, because they are almost completely exempt from paying the electricity price surcharge needed to fund feed in tariff support for VRE generation. Cludius et al. (2014) provide a full quantification of costs and savings for German electricity consumers in 2012. They estimate that the merit order effect reduced wholesale prices over the year by an average of 10 €/MWh, while the surcharge (termed the EEG surcharge) paid by general consumers in 2012 was 35.9 €/MWh. Hence, the net cost of support for VRE generation was approximately 26 €/MWh. (Parenthetically, we note that this is much higher than the combined cost of the LRET and SRES programs to general consumers, which is estimated by the AEMC (2017) to have been A$10/MWh on average across all non-EITE Australian electricity consumers.) Energy intensive consumers in Germany, as in Australia, were substantially exempt from the EEG surcharge, paying only 0.5 €/MWh. Cludius et al. calculate that, had these consumers paid a surcharge of 10 €/MWh, so that they were no worse or better off, taking the merit order effect into account, the surcharge paid by general consumers could have been reduced by 4 €/MWh.

2.2 North American literature

There is a significant body of work analysing relationships between renewable generation and prices in the United States, across a variety of regions and timeframes. From a methodological perspective, the bulk of the literature can broadly be categorised into either empirically-based econometric studies or forward-looking simulation studies as described in Würzburg et al. (2013) above. There is also a smaller number of empirical studies that draw conclusions from observed bidding and cost data without undertaking econometric analysis or statistical regression techniques. This paper will focus primarily on the empirical literature that focuses on prices, but we draw on simulation analysis as relevant. However, the consistency across outcomes in the reviewed studies tends to support the use of regressive techniques as a ‘straightforward and transparent’ means to identify and quantify price reduction Woo et al. (2013). Forward looking studies involving market simulation also broadly support the conclusions reached in the reviewed empirical studies Martinez-Anido et al. (2016).[5]

5. See also: GE Energy. 2005. The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations. Albany, NY: Prepared for NYSERDA. Available at: https://www.nyserda.ny.gov/-/media/Files/...Solar-Wind/wind-integration-report.pdf

GE Energy. 2010a. New England Wind Integration Study. Holyoke, MA: ISO New England Inc. Available at: https://www.iso-ne.com/static-assets/documents/committees/.../newis_report.pdf

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In addition, there is a wealth of literature focussing on the effect of renewables on operating modes of other forms of generation though for the most part this is out of the scope of this paper.[6]

Most empirical studies emphasis is on regions with high and/or growing wind and solar renewable penetrations such as ERCOT (Texas), and CAISO (California) however there are also studies focussing on other regions including New England ISO, Pennsylvania New Jersey Maryland (PJM), Pacific North West and Mid-West. This is understandable as these regions provide an 'of-scale' case study for assessing the impacts of increased renewables deployment.

Wiser et al. (2017) undertakes a comprehensive review of empirical studies that examine the effect of variable renewable energy (VRE) on wholesale prices in the US. The review finds that in general higher variable renewable energy (VRE) drove modest reductions in average wholesale electricity prices and that the main driver of lower prices in the US has been the falling price of natural gas. Table 1 summarises their findings.

Table 1: Impact of renewables on wholesale prices in US electricity markets

Study	Applicable region	Time period	Average VRE penetration (% of demand)	Decrease in average wholesale price from average VRE
Woo et al. 2011	ERCOT	2007–2010	Wind: 5.1%	Wind: $2.7/MWh (ERCOT North) $6.8/MWh (ERCOT West)
Woo et al. 2013	Pacific NW (Mid-C)	2006–2012	N/A	Wind: $3.9/MWh
Woo et al. 2014	CAISO (SP15)	2010–2012	Wind: 3.4% Solar: 0.6%	Wind: $8.9/MWh Solar: $1.2/MWh
Woo et al. 2016	CAISO (SP15)	2012–2015	Wind: 4.3% Solar: 2.6%	Wind: $7.7/MWh Solar: $2.1/MWh
Gill and Jin 2013	PJM	2010	Wind: 1.3%	Wind: $5.3/MWh
Wiser et al. 2016[a]	Various regions	2013	RPS energy: 0%–16% depending on the region	RPS energy: $0 to $4.6/MWh depending on the region
Jenkins 2017[b]	PJM	2008–2016	N/A	Wind: $1–2.5/MWh
Haratyk 2017[b]	Midwest Mid-Atlantic	2008–2015 2008–2015	N/A	Wind: $4.6/MWh Wind: $0/MWh

Notes: a – Price effect is estimated impact of RPS energy relative to price without RPS energy in 2013 before making adjustments due to the decay effect discussed by the authors. b – Decrease in average wholesale prices is based on change in wind energy from 2008–2016 (Jenkins 2017) or 2008–2015 (Haratyk 2017), rather than the decrease from average wind reported in other rows.

Source: Wiser et al. (2017)

6. See for example: Haratyk, G. 2017. Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Implications and Policy Options. Energy Policy 150–66.

   Woo, C. K., Moore, J., Schneiderman, B., Ho, T., Olson, A., Alagappan, L., Chawla, K., Toyama, N. and Zarnikau, J. 2016. Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets. Energy Policy, 92, 299–312.

   Fell, H, and Kaffine, D. T. 2018. The Fall of Coal: Joint Impacts of Fuel Prices and Renewables on Generation and Emissions. American Economic Journal: Economic Policy, 10 (2): 90–116.

An alternative expression of the impact of renewables on wholesale prices is to compare the change in wholesale price ($/MWh) per percentage point increase in VRE penetration. Table 2 summarises the results in the North American studies reported in Wiser et al. (2017).

Table 2: Impact of wholesale prices per % increase in VRE production

Study	Change in price ($/MWh) per % increase in VRE penetration
Brancucci Martinez-Anido et al. (ISO-NE)	-$0.15
Deetjan et al. (ERCOT)*	-$0.25
EnerNex (EI)	-$0.46
Fagan et al. (MISO)	-$0.28
GE Energy (2014, PJM)	-$0.50
LCG (ERCOT)	-$0.52
Levin and Botterud (ERCOT)	-$0.41
Mills and Wiser (solar, CAISO)*	-$0.13
Mills and Wiser (wind, CAISO)*	-$0.10
NESCOE (ISO-NE)*	-$0.80
NYISO (NYISO)	-$0.45

Note: Studies denoted with an asterisk report a simple average price while the remainder report a load-weighted average price.

Source: Wiser et al. (2017)

Woo et al. (2011) examines the impact of wind generation on 15 minute balancing prices in ERCOT's four zonal markets using an ordinary least squares (OLS) approach. The study uses the exogenous Henry Hub gas price to quantify the effect of the marginal fuel (natural gas) on price given endogeneity with dispatchable generation data, finding a statistically significant relationship between wind generation and market price with a 100 MWh increase in wind generation reducing market price by between US$0.32/MWh to $1.53/MWh across ERCOT's four zones.

Woo et al. (2013) uses similar techniques to assess impacts on the hydro rich regions of the Pacific North-West, finding short run reductions in day-ahead prices of US$0.1 0.4/MWh over the short run and $0.56/MWh over the long run for a 100MW increase in average wind generation. Their study also suggests wind generation can have larger impacts when the transmission network is constrained. In the absence of data on day-ahead wind potential the study uses actual wind generation as an instrument to reflect consensus day ahead wind generation.

In order to assess price impacts of wind on PJM electricity prices Gill and Lin (2013) use a robust locally weighted least squares approach. The study notes the strong parametric assumptions required for the application of classical OLS estimation, which would be ambitious in a region such as PJM. Results using their approach show that the quantified expected benefits to wholesale market participants may be substantial despite the relatively low wind-power penetration levels still observed within PJM relative to other markets. In addition, the quantified unitary benefits outweigh, by a big margin, the renewable energy credits given to qualifying windfarms across the market.

Woo et al. (2016) examines merit order effects of both wind and solar generation on CAISO's day ahead (DA) and real time (RT) markets confirming that growth in renewable energy tends to reduce prices by $1.9 5.3/MWh (solar) and $1.4-3.5/MWh (wind) in day ahead markets and $1.0 3.7/MWh (solar) and $1.5-11.4/MWh (wind) in real time markets. The study also assesses price divergence across DA and RT markets concluding that rising solar and wind energy forecast errors tend to reduce the RT prices because unanticipated increases in renewable energy reduce real-time net loads.

A more recent study by Bushnell and Novan (2018) not reviewed in Wiser et al. (2017), studies the intertemporal impact of increased solar penetration on wholesale prices in California. They present results which can be directly compared with the European findings. Their study uses hourly data over the period from January 2013 to May 2017. On average over this period solar (including both PV and solar thermal) supplied 6% of generation and wind 6.5%. The overall finding was that solar generation reduced wholesale prices by an average of US$3.9/MWh and wind by an average of US$7.1/MWh. Expressed in terms of shares of total generation, these figures covert to US$0.65 per percentage point share of solar and US$1.1 per percentage point share for wind. Wholesale market prices varied over the period, in part, as the study demonstrates, because of the effect of additional solar and wind generation, but averaged about US$35/MWh. Hence the effects of both wind and solar generation are to reduce market prices by roughly 2% per percentage point share of renewable generation. Their study is however differentiated from prior work in two aspects in that it rather than focussing only on average prices it examines price response across different hours of the day and across seasons. The conclusions suggest while solar capacity expansion has driven prices lower on average, the impacts across a day are differentiated with decreases in mid-day prices but increases in prices across shoulder periods. This implies that the market is able to sustain more flexible conventional generation, while seriously undermining the economic viability of traditional baseload generation technologies.

The issue of price volatility is addressed in Wiser et al. (2017) concluding that while average energy prices reduce with increased renewables capacity, the volatility of prices is likely to increase. This is supported by Woo et al. (2011), Woo et al. (2013), Woo et al. (2016), Martinez-Anido et al. (2016), Bushnell and Novan (2018).[7]

Relative to literature of wholesale costs, there are far fewer studies on the retail impact of renewable electricity. Wiser et al. (2017a) summarises the work undertaken to date in the U.S., noting the wide range of estimated historical and possible future impacts

2.3 Australian literature

For Australia, a study by Forrest and MacGill (2013) analysed the relationship between wind generation and NEM spot prices, using 30 minute data for a two year period 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 year period, 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. (2014a) also using 30 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. In Germany,

7. Wiser et al (2017) also reviews the impact of VRE on system costs, specifically, the ability of VRE to offset the cost of other bulk power system asset. It concludes that the system value will tend to decline on the margin as VRE penetration increases, resulting from changes in the energy and capacity values of VRE, and the changing need for balancing services and transmission capacity.

Spain and Italy, the costs of VRE support programs is recovered from consumers through an annually fixed retail price surcharge. In Australia, by contrast, these costs are determined through an only partially transparent market mechanism, and the pass through to consumers is (ignoring the effect of exemptions) neither consistent between consumers nor transparent. Emissions Intensive Trade Exposed (EITE) energy users were by far the largest beneficiaries. The authors conclude:

> "Contrasting the estimated reduction in wholesale prices with the costs of the RET to exempt industries, suggests that some companies might be currently significantly overcompensated for their contribution to the costs of the RET by the merit order effect of wind, particularly those exempt from 90% of RET costs. There is scope for re-examining these assistance rates in light of reduced wholesale prices due to merit order effects, as a broader liability base could reduce the cost of the RET to remaining electricity consumers, and, in particular, households."

3 International comparison of household electricity prices

This chapter explores household electricity prices, drawing on the estimates of these prices from official sources (Eurostat, the OECD, Ofgem and various official reports). The focus here is on those countries in Europe that have the highest residential prices (prices in Great Britain are amongst the highest before taxes, and prices in Denmark, Germany and Italy are the highest after taxes). In these countries renewable electricity production has expanded over the last decade. The examination seeks to shed some light on the relationship between renewable electricity expansion and residential electricity prices.

Methodology in high level comparisons such as these matter greatly. Our objective is to present comparisons that are generally true. However the specific situation for an individual customer will vary for many reasons including the level of their consumption, location, tariff type, retailer, access to concessions, and self-generation (typically rooftop PV) and the terms of their retail offers. The usual caveats that apply to the analysis of aggregate average numbers, as here, apply.

Some customers may pay very much less (or more) than the averages that are used here. Effort has been made to present as complete analysis as possible using official data sources and this has meant at some points assembling data from various sources, whose definitions are often similar but not necessarily exactly the same. Ensuring a comparable analysis has required some manipulation and where this has occurred it is explained in the footnotes. All currency amounts are 2017 Australian dollars and foreign currencies are converted to Australian dollars at the 2017 market exchange rates specified by the OECD (0.67 Euro per Australian Dollar)

The chapter proceeds by progressively disaggregating average bills. The text preceding each chart draws out the pertinent observations from the data displayed in the chart. The first sub-section compares the selected European countries with each other. The second sub-section compares Australian prices with those in Europe. While the focus here is on prices paid by households, Appendix A presents charts focussing on the price paid by non-residential medium to small electricity users and at various points in this chapter salient points relating to the difference between residential and non-residential prices are noted.

3.1 European comparison

Figure 1 contrasts electricity prices before and after taxes. Denmark, which typically has the highest prices after taxes, also has lower prices than the other countries before taxes. The situation is reversed for Great Britain.

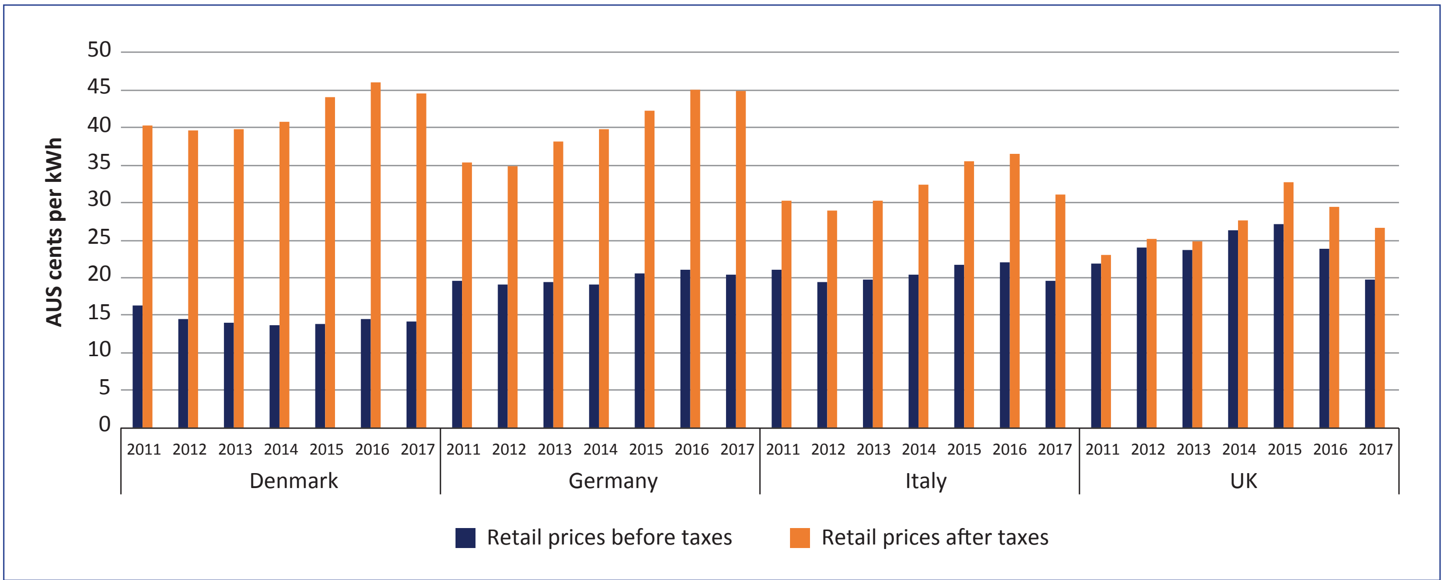

Figure 1: Household electricity prices – consumption Band DC (2,500 kWh < Annual consumption < 5,000 kWh). Source: Eurostat (https://ec.europa.eu/eurostat)

Figure 2 shows the electricity bills broken down into three components – energy and supply, networks and taxes, levies and charges for consumption band DA (unfortunately Eurostat does not present a breakdown for the preferred Band DC). Nevertheless it is clear from this that taxes are by far higher in Denmark and Germany than Italy or Great Britain (although growing in both of these countries). It is also clear that energy and supply costs are much lower in Denmark than elsewhere and network costs much higher in Germany than in the other countries).

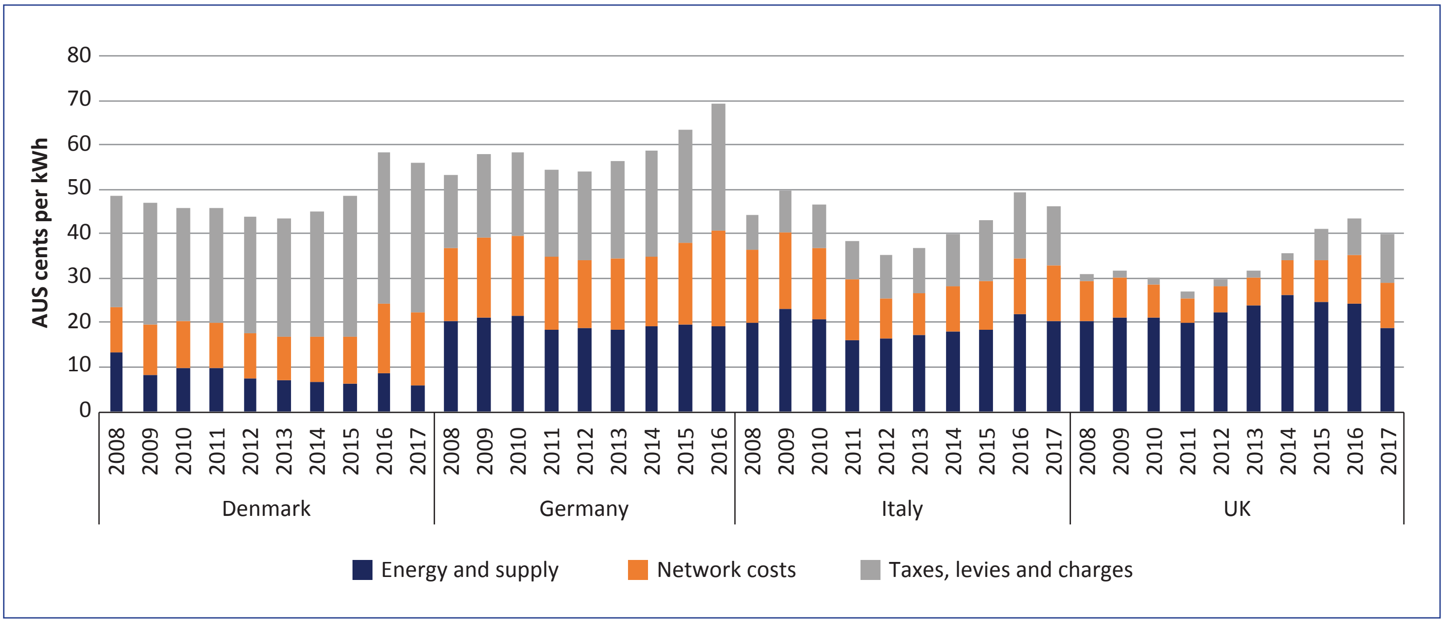

Figure 2: Electricity price components – consumption Band DA (Consumption less than 1,000 kWh per year)
Source: Eurostat (https://ec.europa.eu/eurostat)

Figure 3 shows that as renewable energy as a proportion of total electricity production has risen, so wholesale prices have declined. This is consistent with the "merit order effect" in the literature reviewed earlier.

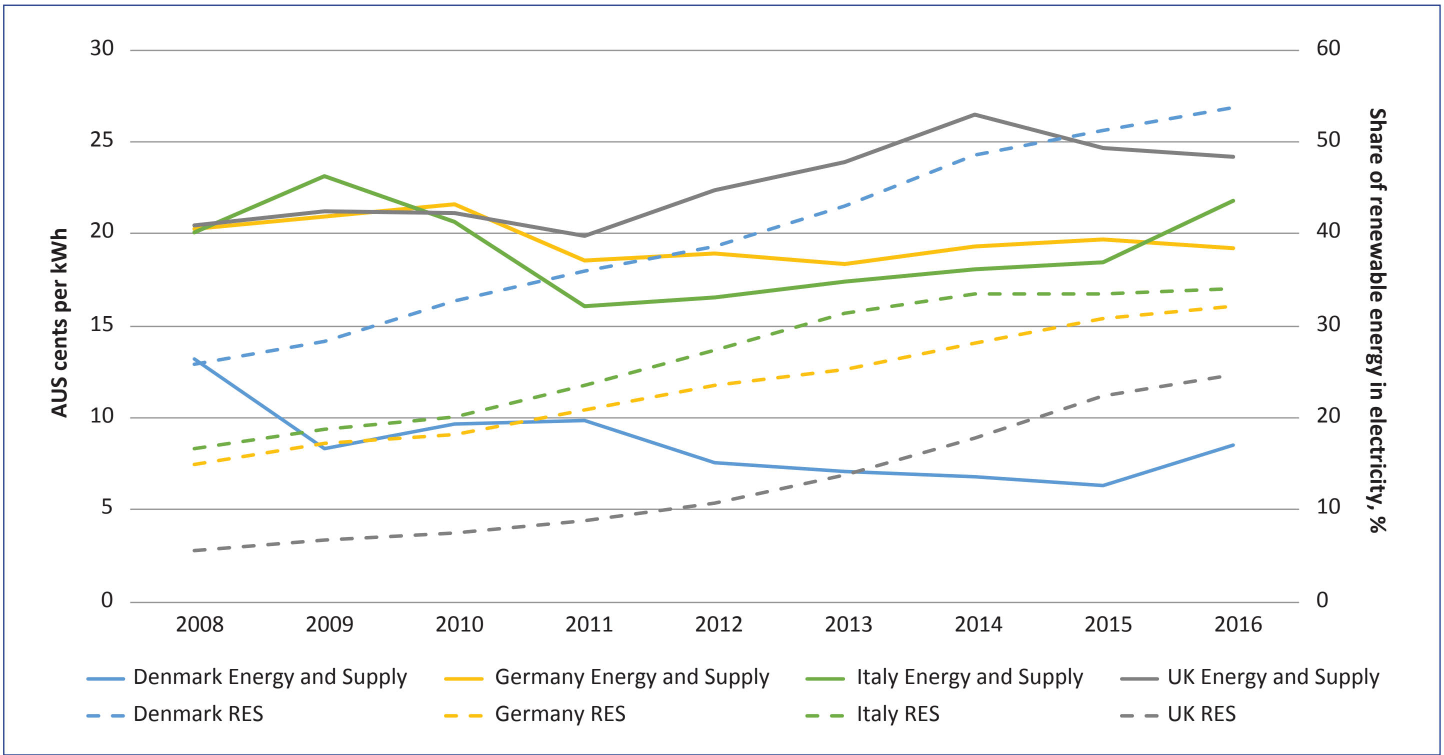

Figure 3: Renewable energy share versus wholesale prices
Source: Renewable Energy Shares source is Eurostat (https://ec.europa.eu/eurostat) and wholesale prices from ACER (https://www.acer.europa.eu/)

Figure 4 shows that as the share of production from renewable sources has increased, so have after-tax electricity prices. This suggests that the effect of wholesale price reductions have been more than off-set by increases in other costs including the charges for retailing (supply) and taxes, levies and charges. Further analysis of these data (not shown here) finds that "energy and supply" costs (i.e. the costs of producing and selling electricity) typically decreased as renewables have increased, except in Britain.

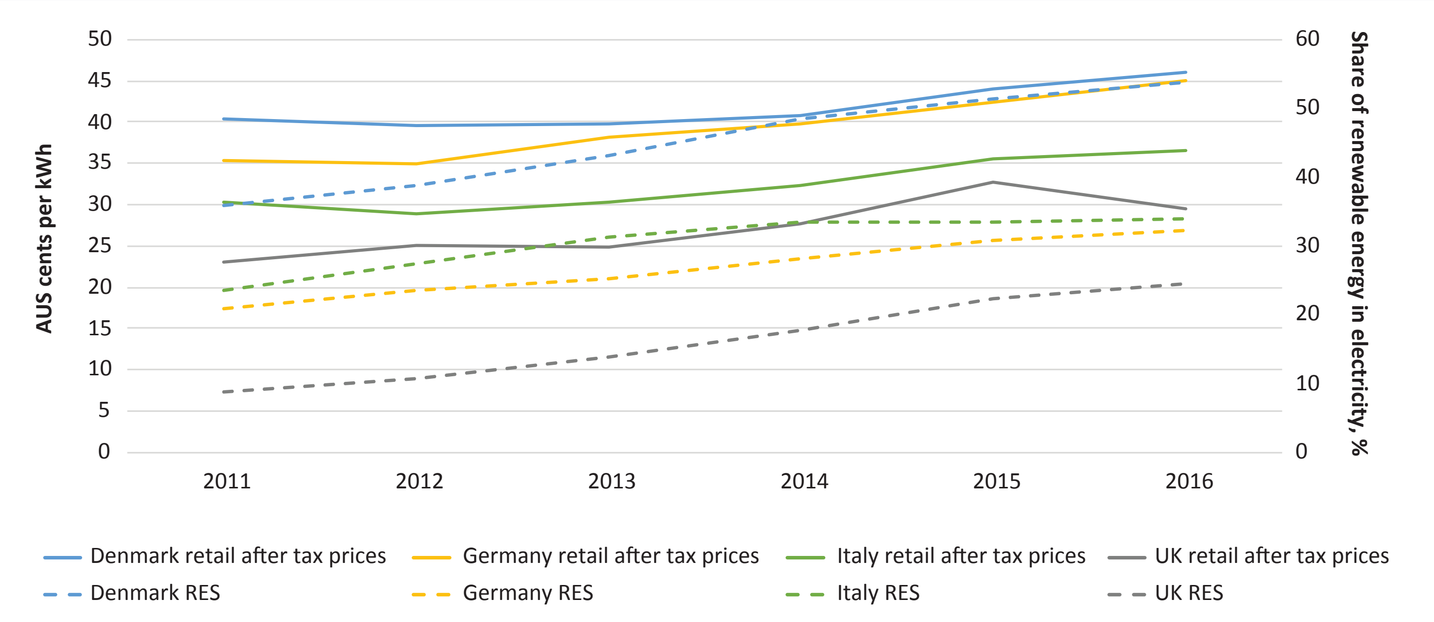

Figure 4: Renewable energy share versus after-tax prices

Source: Eurostat (https://ec.europa.eu/eurostat) for consumption Band DC (2,500 kWh < Consumption < 5,000 kWh).

Figure 5 shows that taxes, levies and charges have tended to increase as the share of renewable production has increased. Eurostat does not however break these taxes, levies and charges up and so further analysis is needed to determine whether the increase in taxes, levies and charges is explained by higher subsidies for renewables.

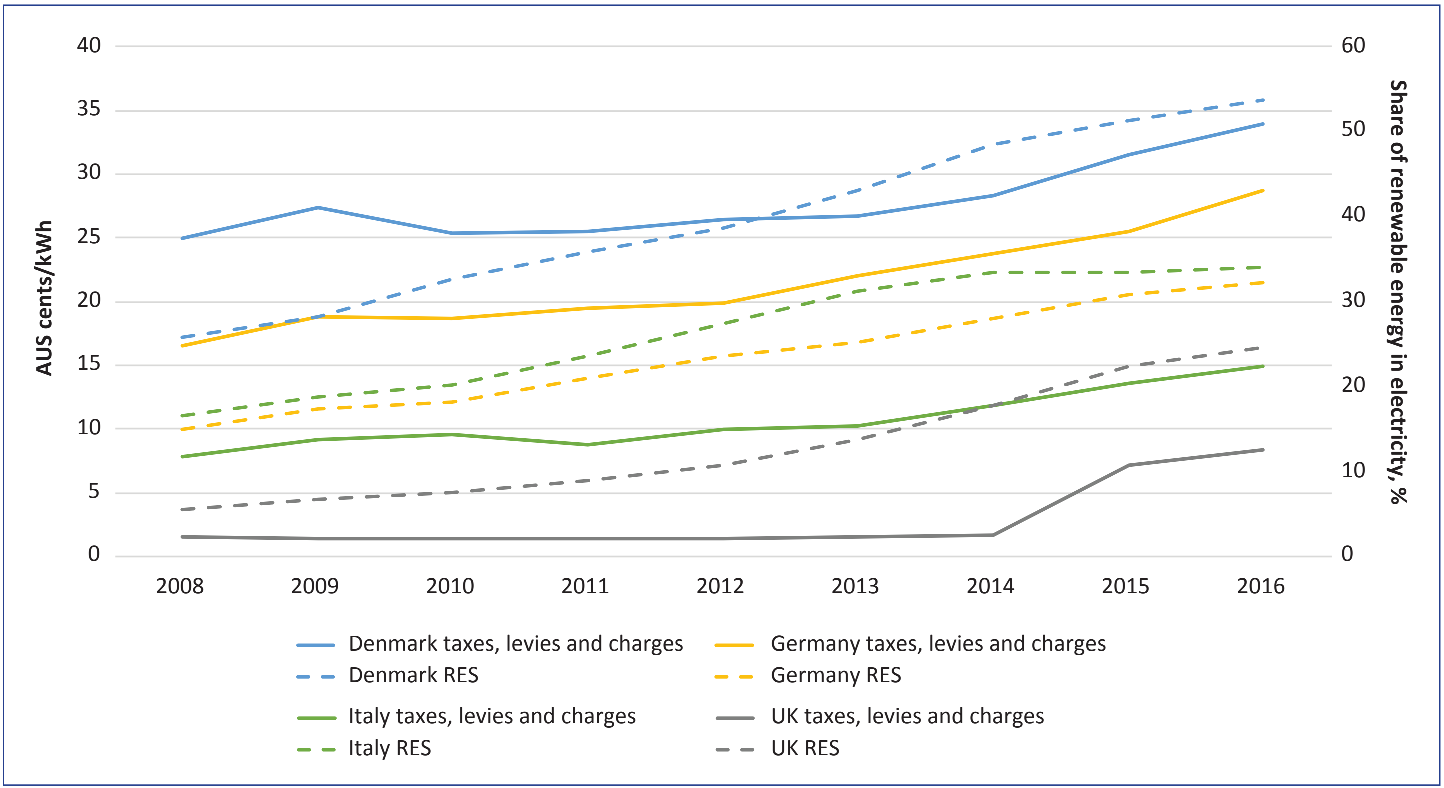

Figure 5: Renewable energy share versus taxes levies and charges

Source: Eurostat (https://ec.europa.eu/eurostat)

Figure 6 presents a breakdown of German residential electricity bills for a 3,500 kWh per year customer. It shows that over the period from 2009 when acquisition/sales (i.,e. production and retailing) charges were the highest, to 2017 (when they were the lowest), the reduction in this charge partially offset the surcharge for the promotion of renewables. The renewables surcharge has grown from an insignificant proportion of the bill in 2006 to be approximately equivalent to the acquisition/sales charge in 2017. The renewables surcharge nonetheless remains less than the sum of concession fees, VAT and other surcharges.

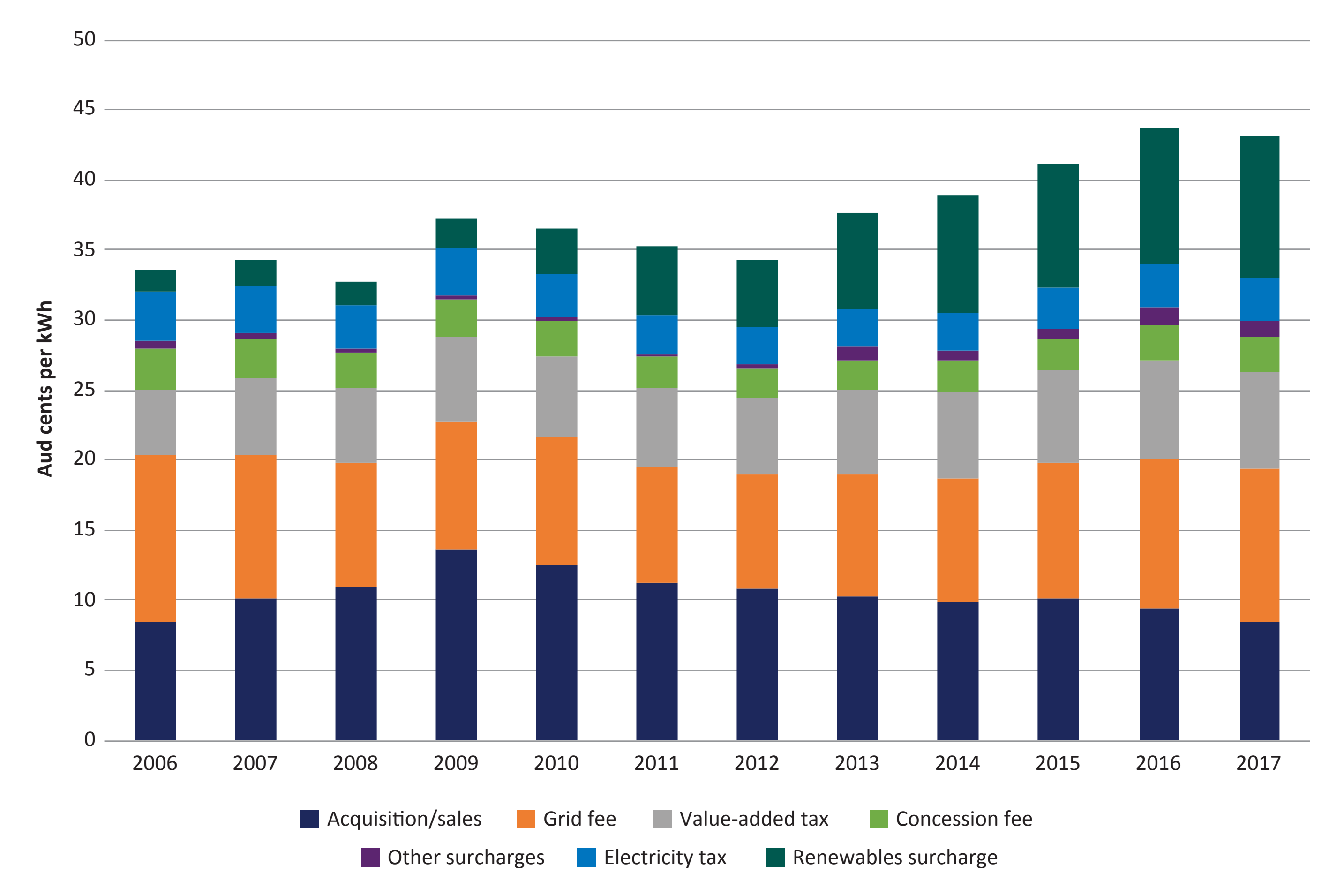

Figure 6: German household electricity bill breakdown

Source: BDEW, https://www.bdew.de. Average retail electricity rates are for households consuming 3,500kWh per year.

Figure 7 presents a breakdown of household electricity bills that distinguish the “basic price component” (i.e. the electricity industry specific charges) and then amounts for the cost of non-climate policies).[8] The chart shows that a decline in the “basic price component” from 2008 to 2017 largely offsets an increase in the cost of climate policies.

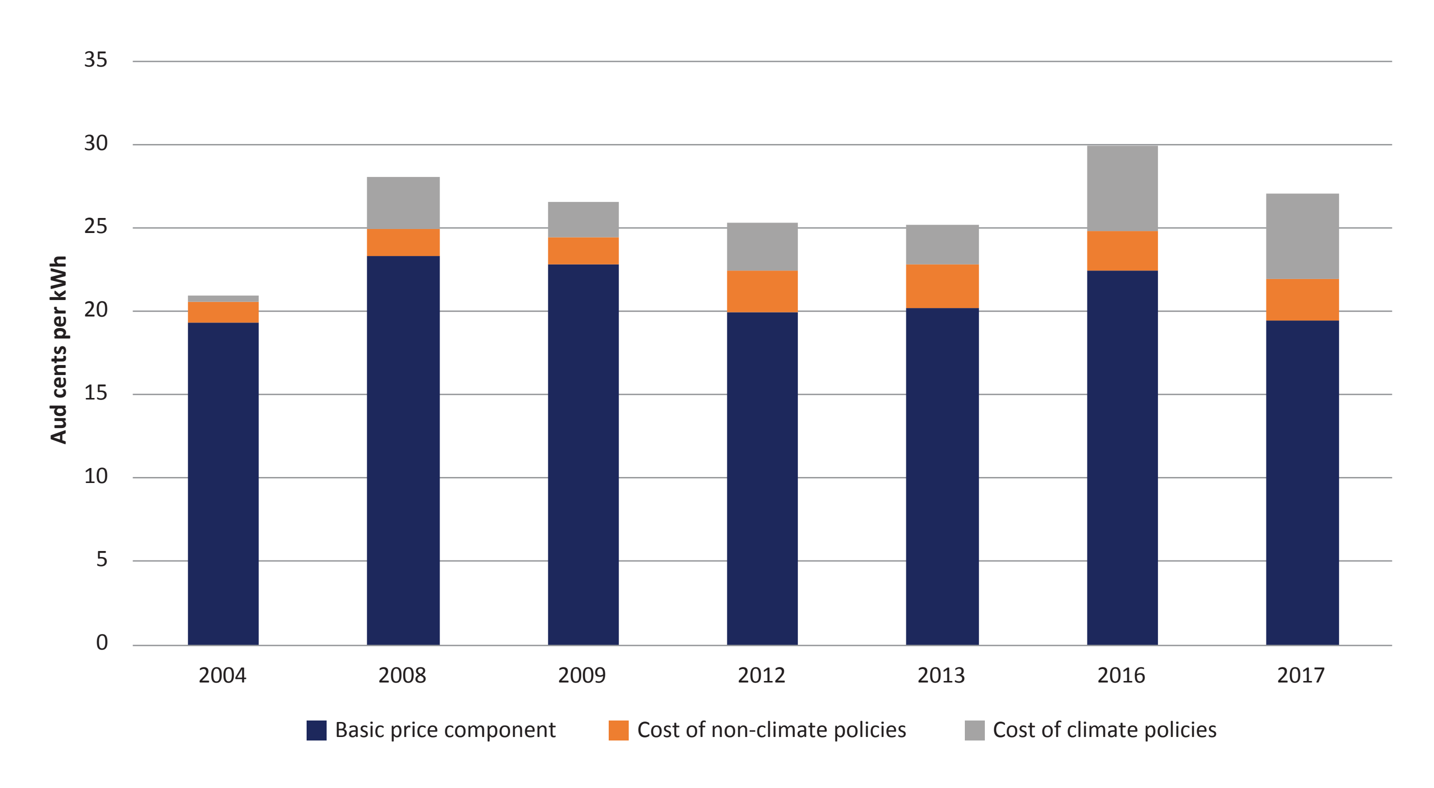

Figure 7: Breakdown of household electricity bills in the UK

Source: For the years 2004, 2008 and 2016, the data source is Committee on Climate Change analysis[9].For the years 2009 and 2012, the data source is Ofgem Household Energy Bills Explained-Factsheets[10].The 2013 data is obtained from Committee on Climate Change analysis[11]. The 2017 data source is Eurostat.

8. The nature of the breakdown is inspired from the Committee on Climate Change analysis, Figure 1.7: https://www.theccc.org.uk/publication/energy-prices-and-bills-report-2017.

   For the years 2009 and 2012, the energy bill breakdowns is available in percentages and are used to calculate the bill components in real prices by using the retail prices. The source of retail price is Eurostat database. Retail prices are for consumption Band DC (2,500 kWh < Consumption < 5,000 kWh).

   The 2017 electricity price components are for consumption Band DA (Consumption less than 1,000 kWh). These prices are updated (recalculated?) for consumption Band DC (2,500 kWh < Consumption < 5,000 kWh) by using the price component proportions for band DA.

   2009, 2012, 2013 and 2017 breakdowns are re-grouped into three components: Basic Price Component, Cost of Non-Climate Policies, and Cost of Climate Policies. The following is the description for the three cost components. Basic Price Component includes wholesale price, transmission and distribution cost, suppliers cost, margin and balancing cost, renewable taxes, and environmental taxes. Non-climate policy costs are capacity taxes, warm homes discount, energy efficiency policies aimed at addressing fuel poverty10, smart meters, and VAT. Climate policy costs consists of support for low-carbon generation, EU Emissions Trading System allowances, UK Carbon Price Support, energy efficiency policies aimed at reducing CO2, upgrades to transmission and distribution networks to accommodate renewable generation.
9. https://www.theccc.org.uk/publication/energy-prices-and-bills-report-2017/
10. https://www.ofgem.gov.uk
11. https://www.theccc.org.uk/publication/energy-prices-and-bills-impacts-of-meeting-carbon-budgets-2014

Figure 8 shows that subsidies for the expansion of renewable production in Denmark increased from 2012 relative to previous years, but only accounts for a small part of the total charge for taxes and levies. The step change decrease in 2017 is accounted for by the transfer of support payments for a large windfarm from electricity customers to tax payers. The chart also shows that the decline in the charge for production and sales more than offsets the increase in the charge for renewables expansion.

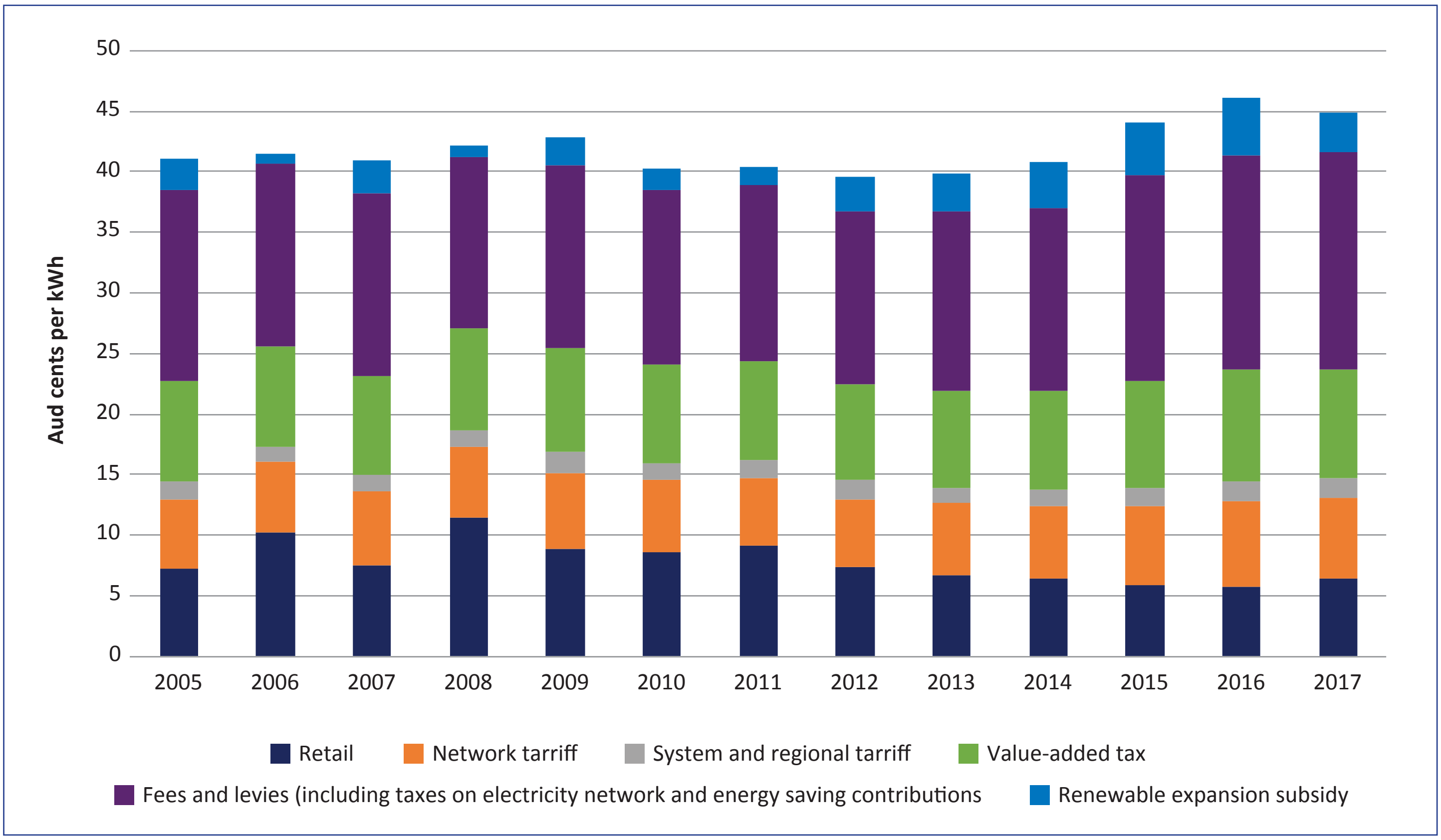

Figure 8: Danish household electricity price breakdown
Source: Danish Energy, https://www.danskenergi.dk

Figure 9 presents the breakdown of the household electricity bill in Italy distinguishing the subsidy for renewables from the other components. It shows that these subsidies are approximately comparable to the sum of taxes and other system charges and have stayed much the same as a proportion of the customers' bills since 2012.

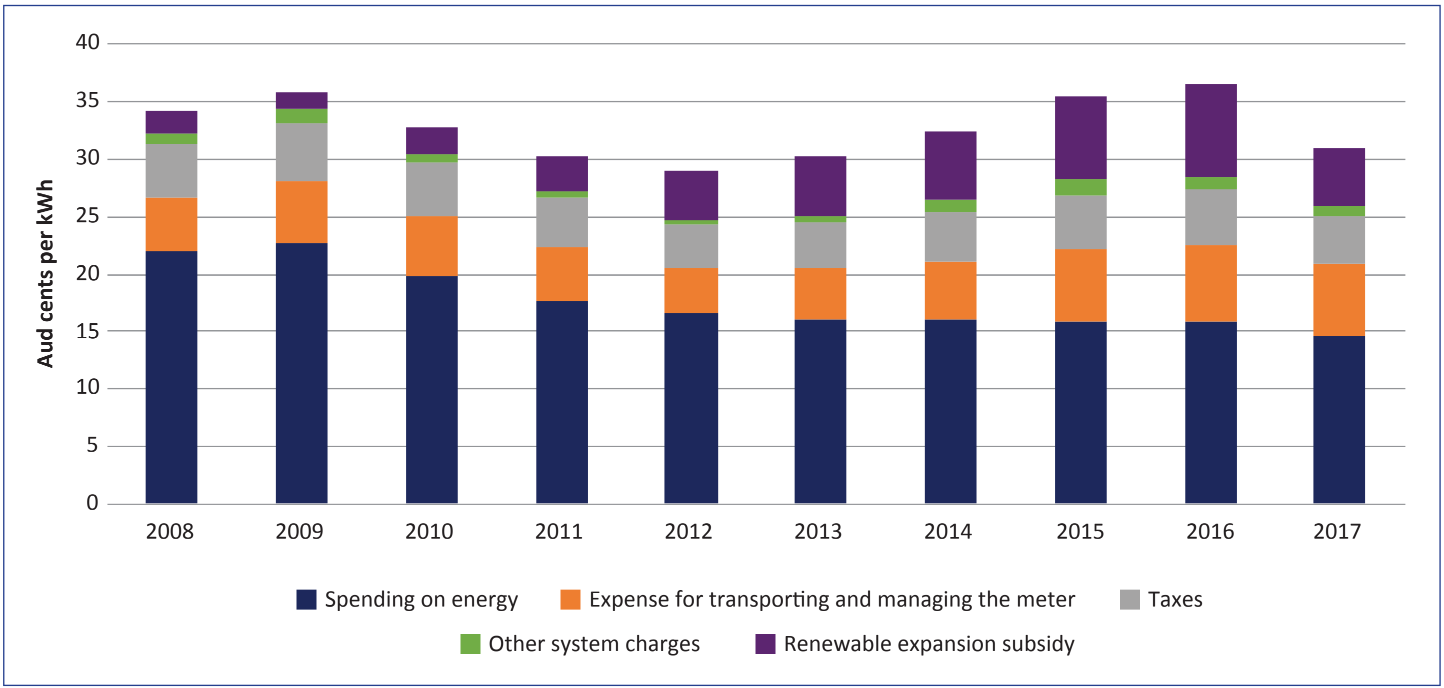

Figure 9: Household bill breakdown in Italy

Source: ARERA, https://www.arera.it. The system charges are broken down into component A3 and other system charges. A3 component is for the promotion of energy production electricity from renewable sources. The source for system charges components is ControlloBolletta.it (https://www.controllabolletta.it). The prices upgraded to consumption Band DC (2,500 kWh < annual consumption< 5,000 kWh) by using Eurostat (https://ec.europa.eu/eurostat) prices where the original prices are for 2,700 kWh of annual consumption. All prices are in 2017 AUD dollars.

The main points from this comparison are summarised as follows:

1. Denmark and Germany have by far the highest residential electricity prices, but this can be attributed to a combination of VAT, excise taxes and renewable support payments. Of these, the VAT and excise taxes dwarf the renewable support payments in Denmark, and are larger than the renewable support payments in Germany.
2. In all countries wholesale prices have decreased as the proportion of electricity from renewable sources has increased.
3. In Italy and Denmark, the decrease in the charge for production and retailing electricity has tended to more than offset the increase in renewable support payments in residential bills.
4. In Germany and Britain, the decrease in the charge for production and retailing of electricity largely offsets the increase in renewable support payments.

3.2 Australia-Europe comparison

Figure 10 compares typical prices in Australia with those in the selected European countries whose price break-downs we are able to establish. As noted earlier, Denmark and Germany are commonly considered to have the highest prices in Europe. Several observations stand out in this comparison:

1. Renewable energy subsidy charges and taxes are much lower in Australia than in the European countries. The pre-tax charge for electricity to households in Australia is around twice the pre-tax charge in the European countries;
2. Wholesale and retail charges are much bigger in all Australian regions than those in Denmark and Germany, and bigger than those in Great Britain and Italy;
3. Network charges in Australia are bigger than in the comparable European countries, although relative to wholesale and retail charges the gap is not as large.

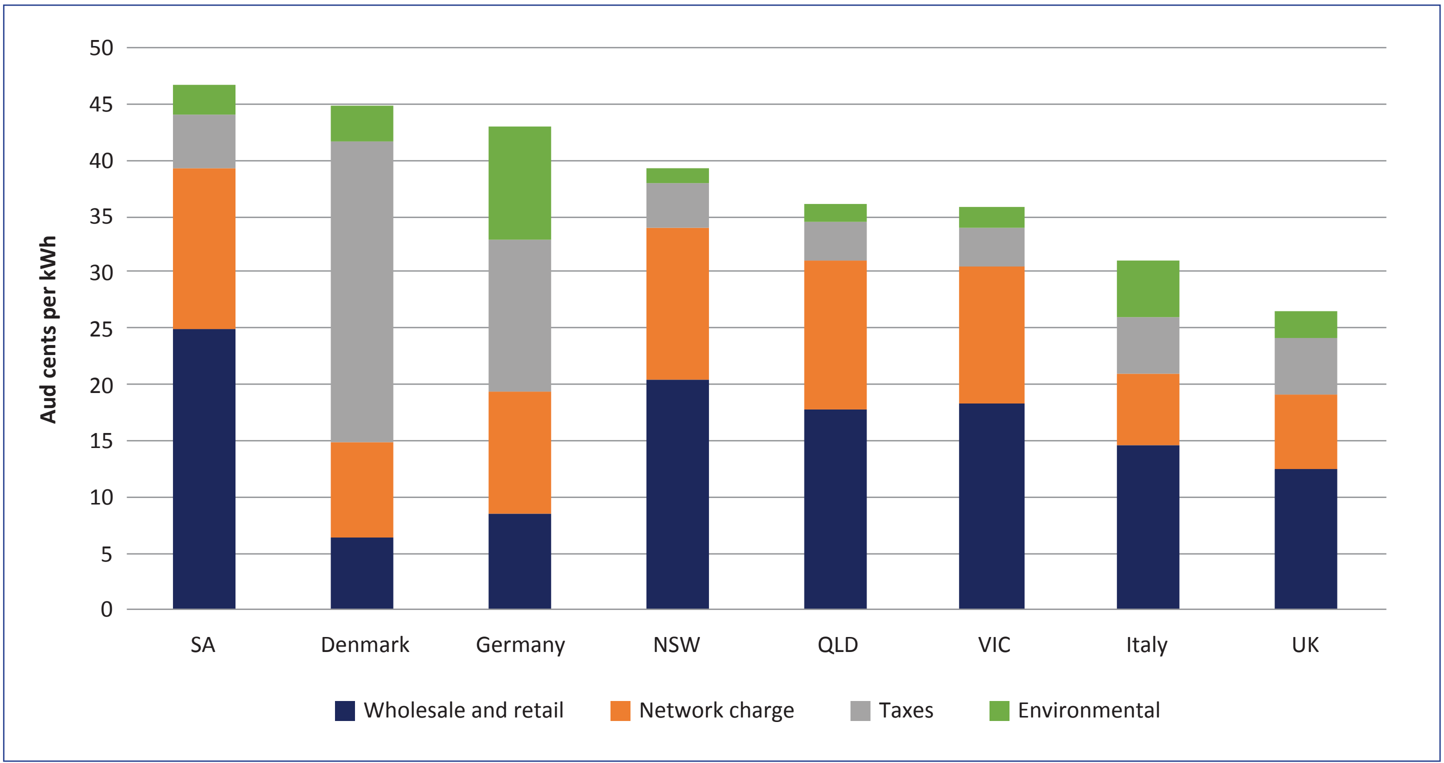

Figure 10: Australia versus Europe household electricity bills

Source: SA, NSW, QLD and VIC data from [MI] Residential Electricity Price Series for December 2017[12] Denmark data[13]. German data from BDEW[14]. UK data from Eurostat. UK electricity price proportions from consumption Band DA (Consumption less than 1,000 kWh) scaled to prices for consumption Band DC (2,500 kWh < Consumption < 5,000 kWh).

12. https://www.miretailenergy.com.au/pdfs/latest.pdf
13. https://www.danskenergi.dk
14. https://www.bdew.de/

4 South Australia in focus

In this section, we analyse how the transition to renewable energy in South Australia has influenced supply and demand. We then apply econometric methods to analyse the South Australian energy market to understand how the transition to renewable energy has affected the electricity spot price.

4.1 Background

4.1.1 Demand

Figure 11 shows the summer and winter demand in the 2013 and 2018 financial years[15], including the 10% and 90% probability of exceedance (POE) range. This measure of demand is after adding back the consumption that has been displaced by distributed solar PV generation, plus the grid export from this distributed generation, which is not visible in the measurement of regional demand. The chart shows that winter day average demand has increased slightly in 2018 compared to 2013, but is essentially unchanged in summer. The charts also show that winter demand in 2018 is more variable[16] than in 2013, but summer variability is largely unchanged.

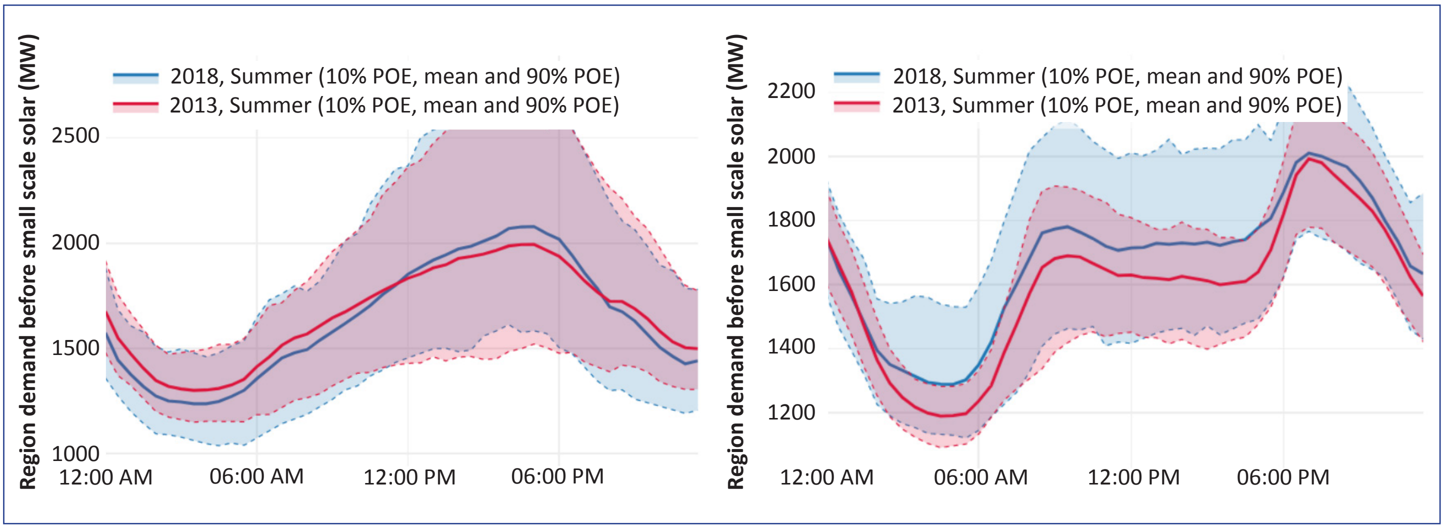

Figure 11: Summer and winter average daily demand without rooftop solar offsetting demand

15. In this section, all references to yearly total and yearly average values refer to the financial year-end values, between 1 July to 30 June, rather than calendar year.
16. Variability is measured by the size of the 90% Probability of Exceedance (POE) band. The 90% POE bounds define the upper and lower limits within which 90% of all the observations from 2013 to 2018 lie.

Figure 12 shows the region demand after the impact of the distributed solar PV production. It shows the effect of distributed solar PV in reducing demand during the day in summer. The same effect though to a lesser degree as expected, is seen in winter.

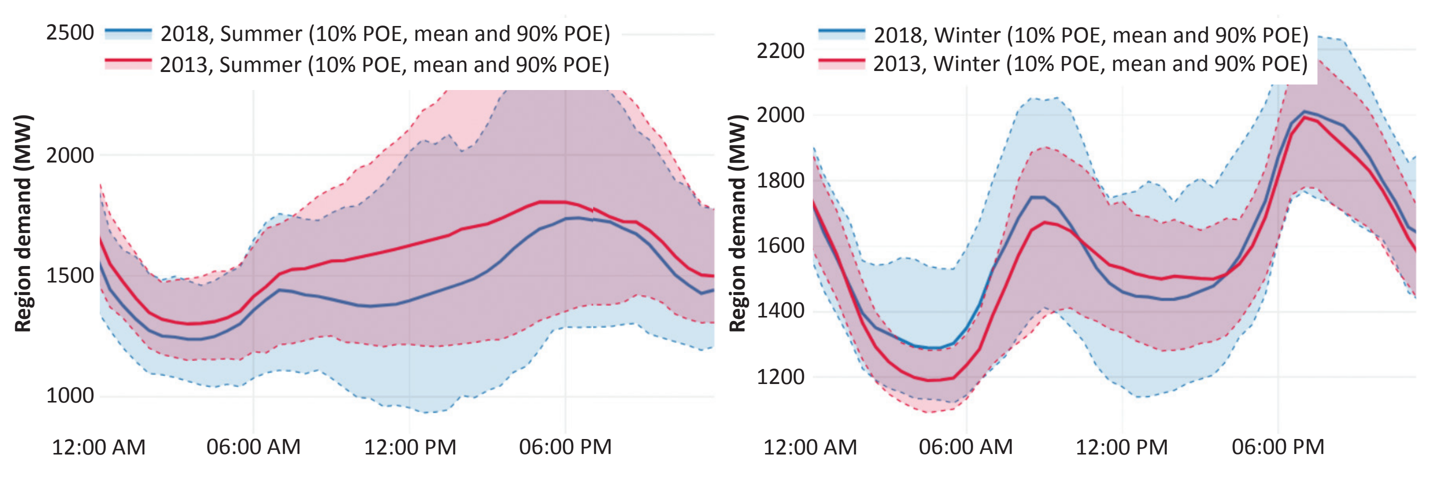

Figure 12: Summer and winter average daily demand with rooftop solar

4.1.2 Supply

Figure 13 shows the breakdown of the South Australian energy production, by technology, between 2013 and 2018. Most 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. Over this period, South Australian small-scale solar generation (less than 100kW per system) far exceeded the large-scale solar generation, which in 2018 was 1,110 GWh and 3.8 GWh respectively. In addition, Victorian interconnector imports increased in 2017, perhaps in part attributable to the closure of the 520 MW Northern coal 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 mid 2017, continued expansion of wind and solar production and significantly higher output from combined cycle gas turbine generation in South Australia.

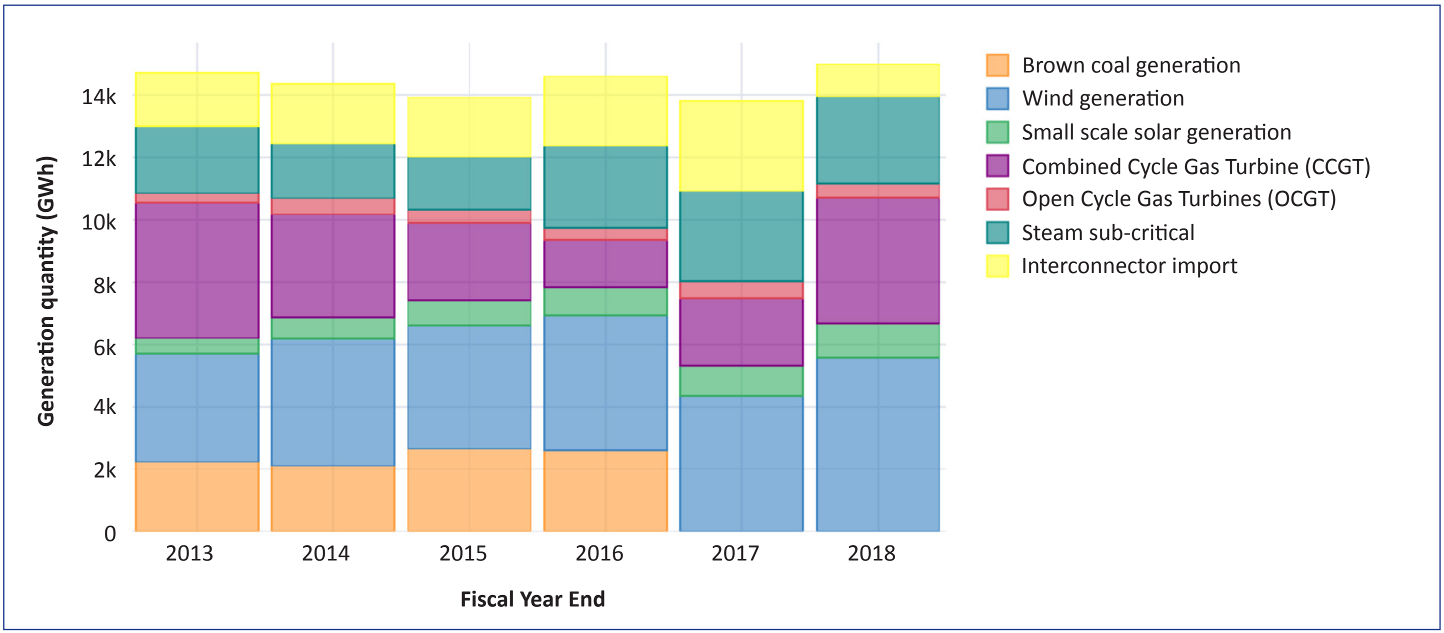

Figure 13: Generation supply mix for South Australia 2013–2018

Figure 14 shows the South Australian 2013 and 2018 daily average PV generation for summer and winter. The variation in cloud cover throughout the season explains the wide POE range.

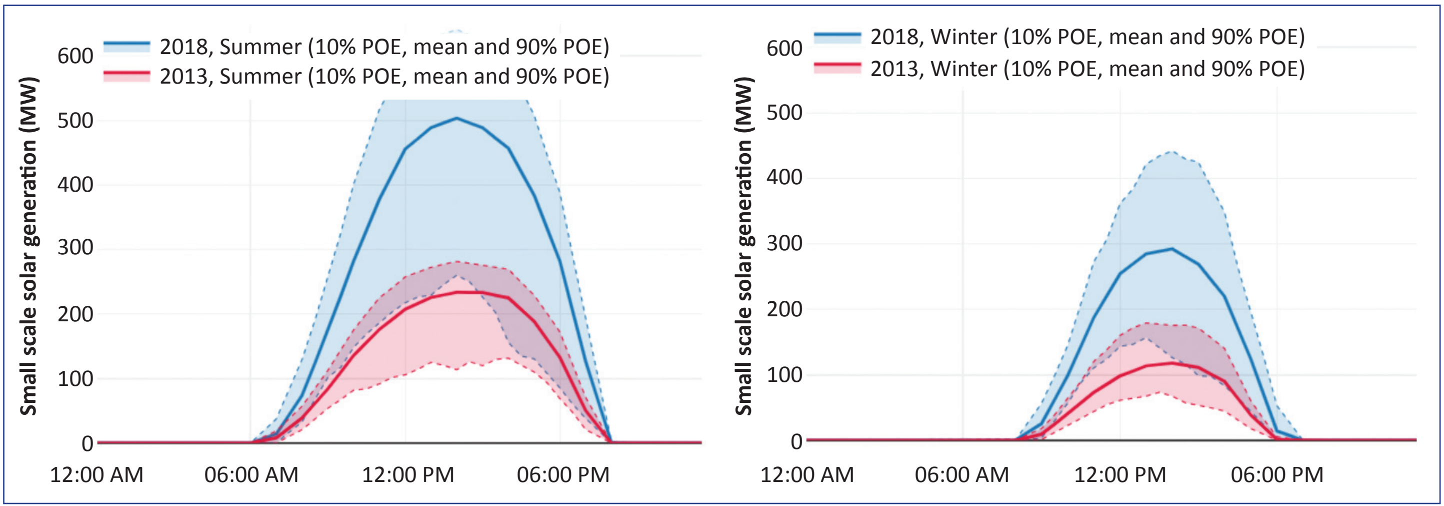

Figure 14: Summer and winter average daily small scale solar supply including the 10% and 90% probability of exceedance (POE) range.

Figure 15 shows the average and range of wind production in summer and winter for 2013 and 2018. The variation in wind speed and hence wind generation throughout the season explains the wide POE range. On average, wind generation is the highest during the morning and evening, when solar is not available.

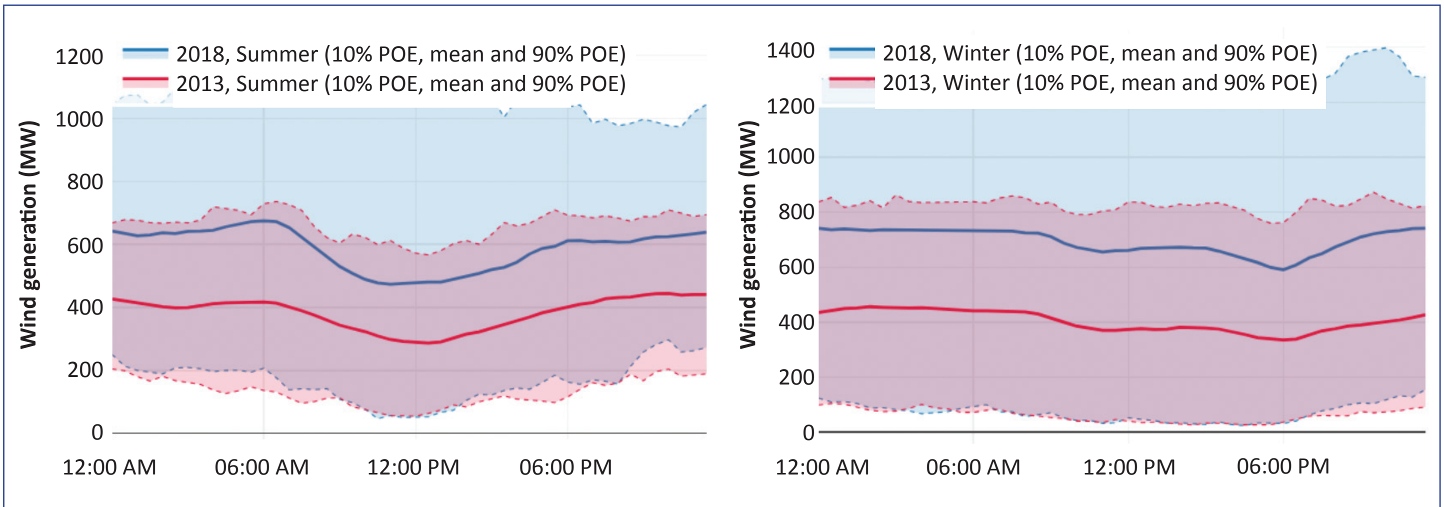

Figure 15: Summer and winter average daily wind generation supply including the 10% and 90% probability of exceedance (POE) range.

Figure 16 shows the winter and summer daily gas supply.[17] It shows higher gas generation in summer in 2018 than 2013, and almost unchanged in winter 2018 than winter 2013, but that typical winter day gas generation is higher than summer. In both seasons it is evident that gas generation is far more variable in 2018 than 2013. It is also particularly notable comparing the gas generation curves and the daily demand curves, how gas generation tracks demand.

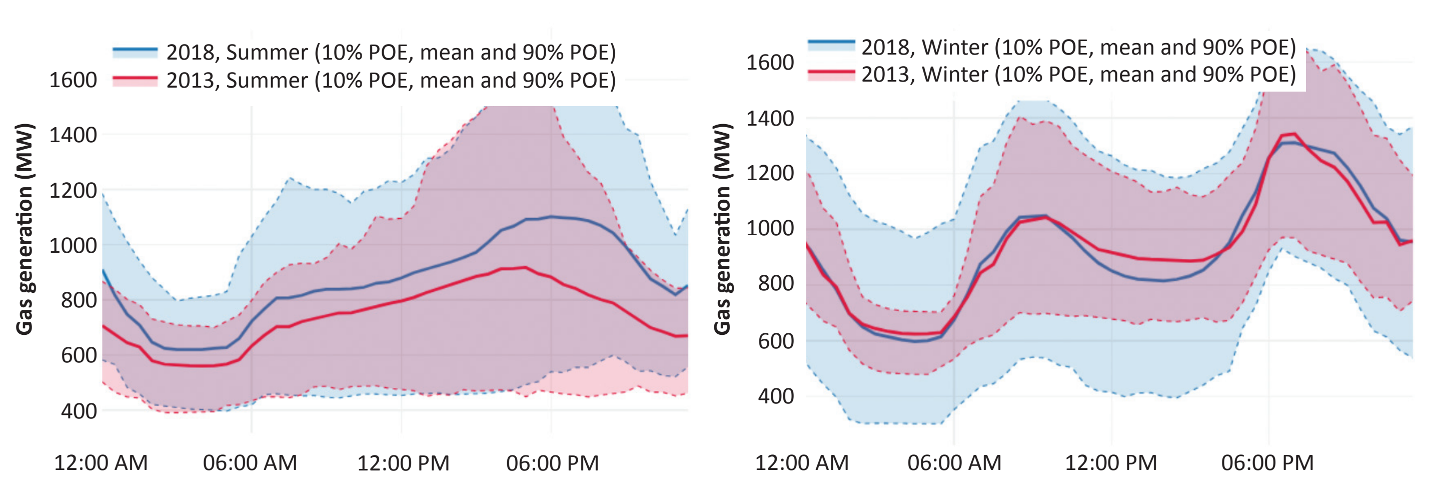

Figure 16: Summer and winter average daily gas generation including the 10% and 90% probability of exceedance (POE) range.

Figure 17 shows the summer and winter gas prices in 2013 and 2018. It shows the daily variability in prices is higher in 2018 than 2013, but the average daily price in summer increased from $5 per GJ to $8.5 per GJ and the average winter price from $6 per GJ to $8.50 per GJ.

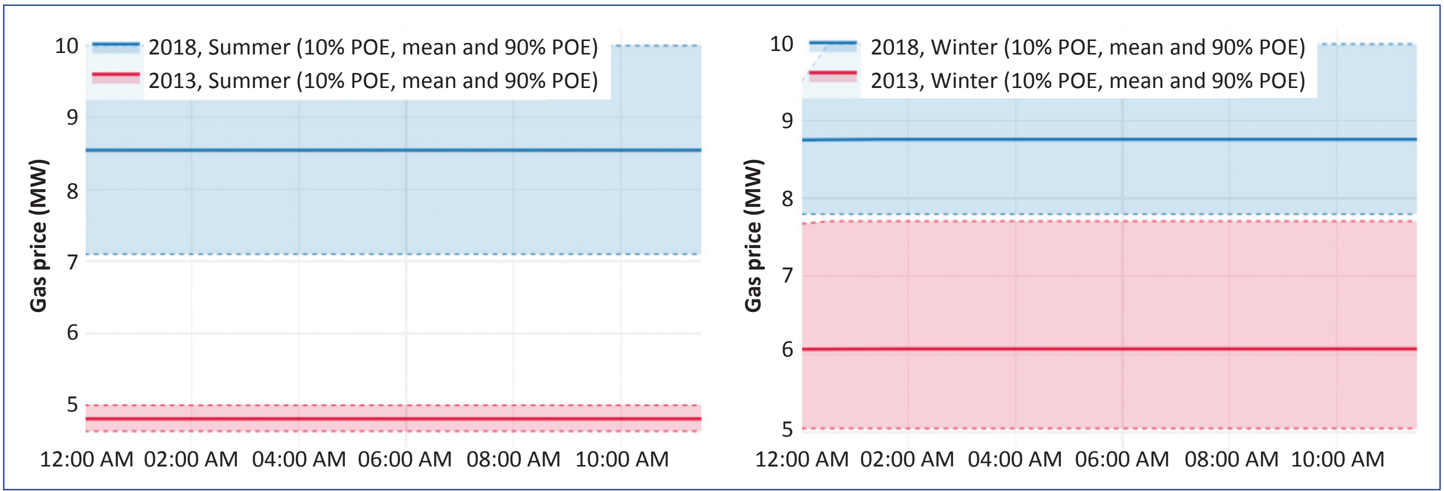

Figure 17: Average Australian gas price

17. Figure C1, in Appendix C, shows a breakdown of the South Australian gas generation by gas turbine type. It shows that the State's Combined Cycle Gas Turbines (CCGT) generation in 2018 accounts for most of South Australia's baseload production, sub-critical steam turbines (SUBCRIT) has a slightly smaller share. South Australia's Open Cycle Gas Turbine (OCGT) generation provides the remainder of the state's conventional production to meet mainly peak demands. OCGT is required to produce during morning and evening peaks in wintertime, while in summer, OCGT only produces mainly in the evening peak. The requirement for the additional OCGT in the mornings in winter will push up morning wholesale prices due to the lower efficiency of OCGT compared to CCGT. For OCGT, the increased running cost per hour is offset by the low capital cost and the intention to run OCGT units during times when wholesale prices are high, as shown in Figure 26. Additionally, the SA Pelican Point CCGT station mothballed half its capacity after 1 April 2015, requiring OCGT and SUBCRIT to cover this capacity when wind and solar was unavailable, though this capacity was returned to the market on 1 July 2017.

The panel of four figures in Figure 18 show the summer and winter average daily imports and exports showing the 10% and 90% probability of exceedance (POE) range for 2013 and 2018. It shows higher exports in 2018 compared to 2013, particularly in winter and also far higher variability in 2018 than 2013. Similarly imports are lower in 2018, again particularly in winter and again showing increasing variability over the period.

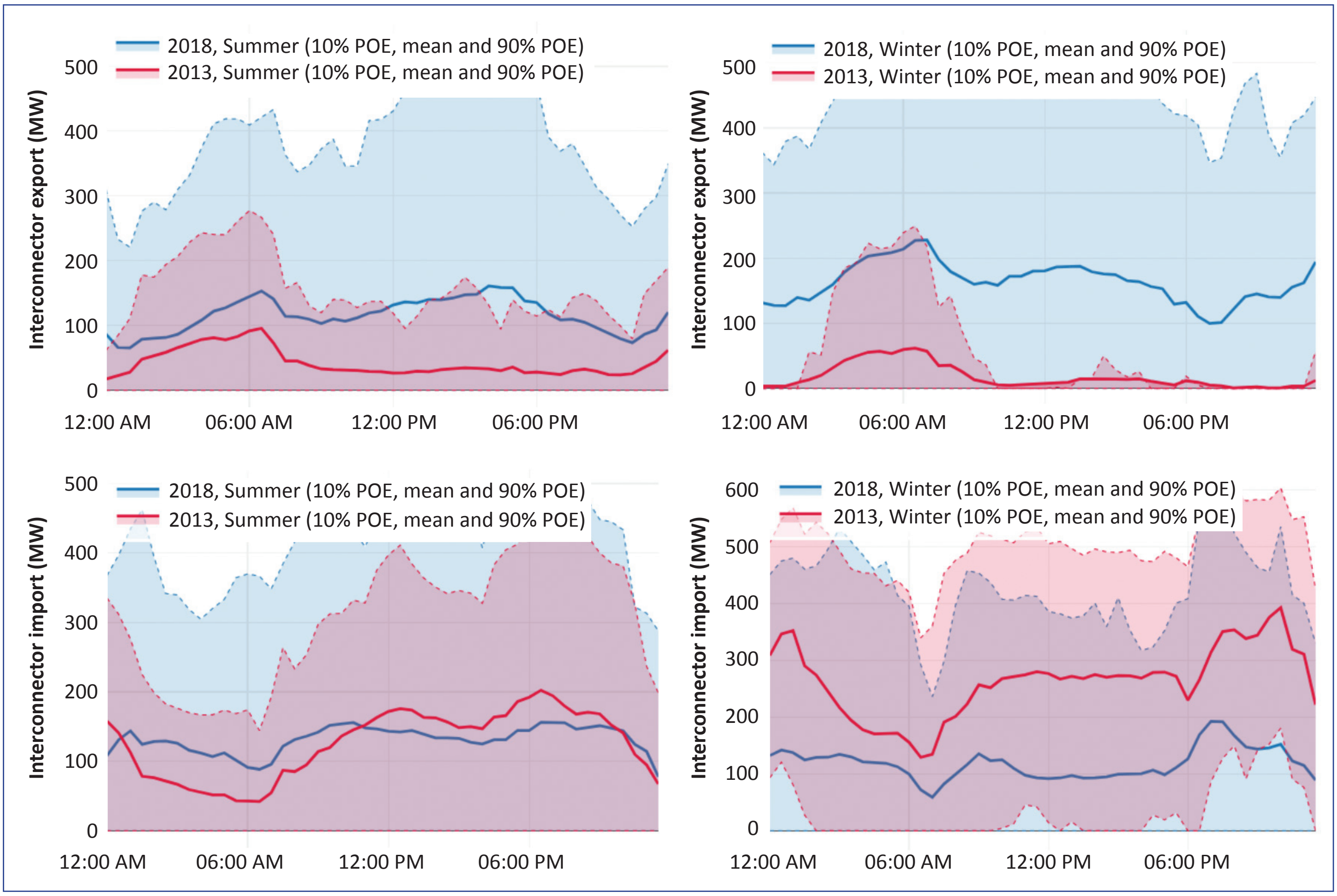

Figure 18: Interconnector import and export

4.1.3 Prices

Figure 19 shows the summer and winter average daily spot price. It is notable that the mean exceeds the 10% POE value between 2pm and 6pm. This is attributable to a few extreme price events during these hours. The “dash-dot” lines shows the mean price but where spot prices greater than $1,000/MWh have been excluded. The winter chart shows greater volatility in prices in the morning period, as might be expected considering the morning peak demands evident in winter but not summer and the requirement for OCGT generation.

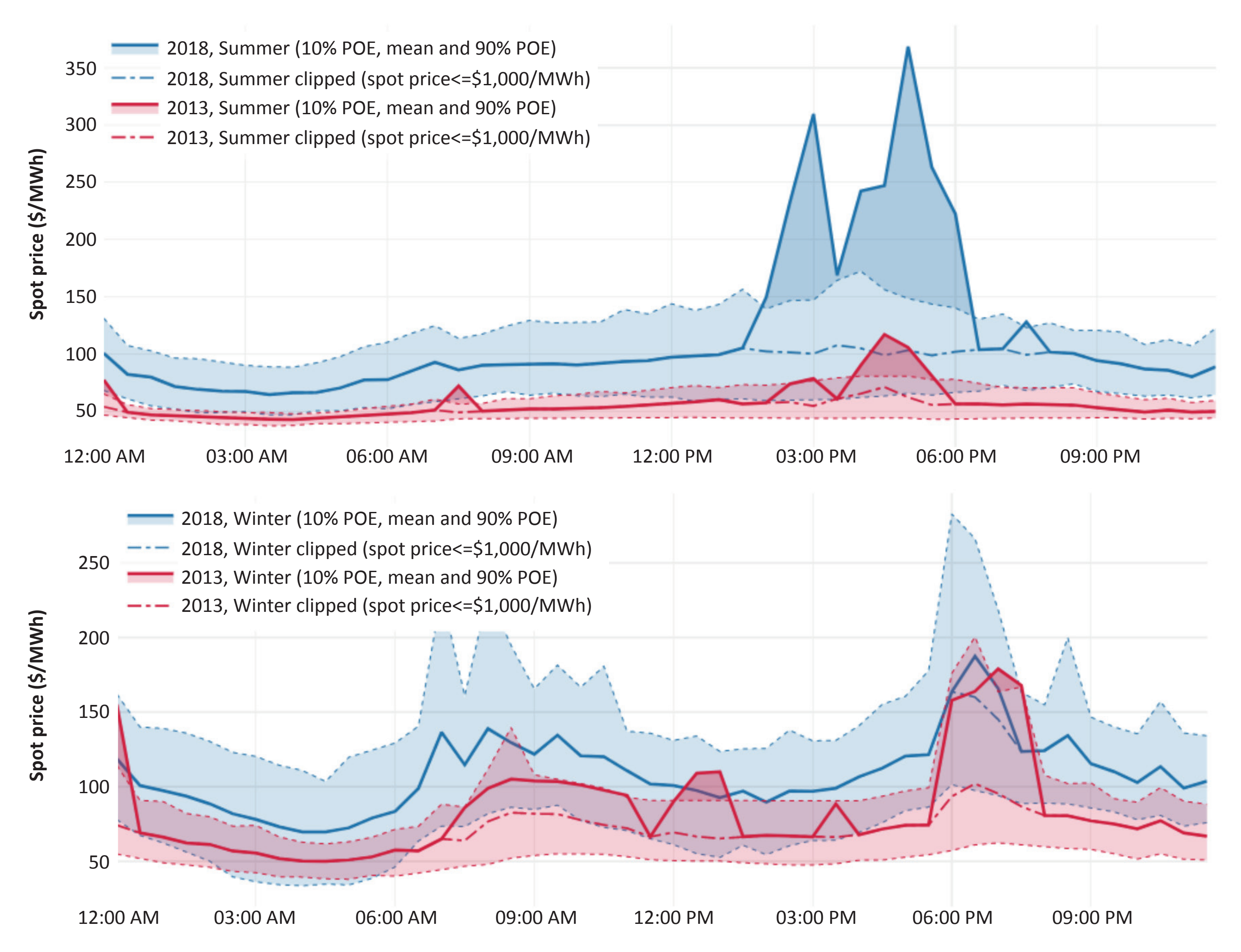

Figure 19: Summer and winter average daily spot price

Figure 20 shows the volume weighted average price (VWAP) for the principal generation sources in South Australia. The VWAP was calculated as the total revenue using the SA spot price for each generation source in each fiscal year, divided by the total generation in that fiscal year; providing a result in $/MWh. On average, the VWAP for all generation types has been increasing since 2012. It shows that OCGT was exposed to the highest spot price values followed by steam Sub-Critical generation. Despite the increase in wind and solar production over this period, the VWAP for wind and solar has continued to increase. The VWAP for the other generation sources increased in 2017, attributable in part to the closure of the Northern Power station in 2016. In 2018 the VWAP for OCGT and Sub-Critical generation has fallen. The Hornsdale Power Reserve (currently the world's largest battery) in South Australia installed near the end of 2017 has a similar VWAP as OCGT. VWAP was low for interconnector exports which indicated that low marginal cost energy, such as wind and solar, was likely exported. VWAP for interconnector imports was comparable to other SA generation sources such as CCGT.

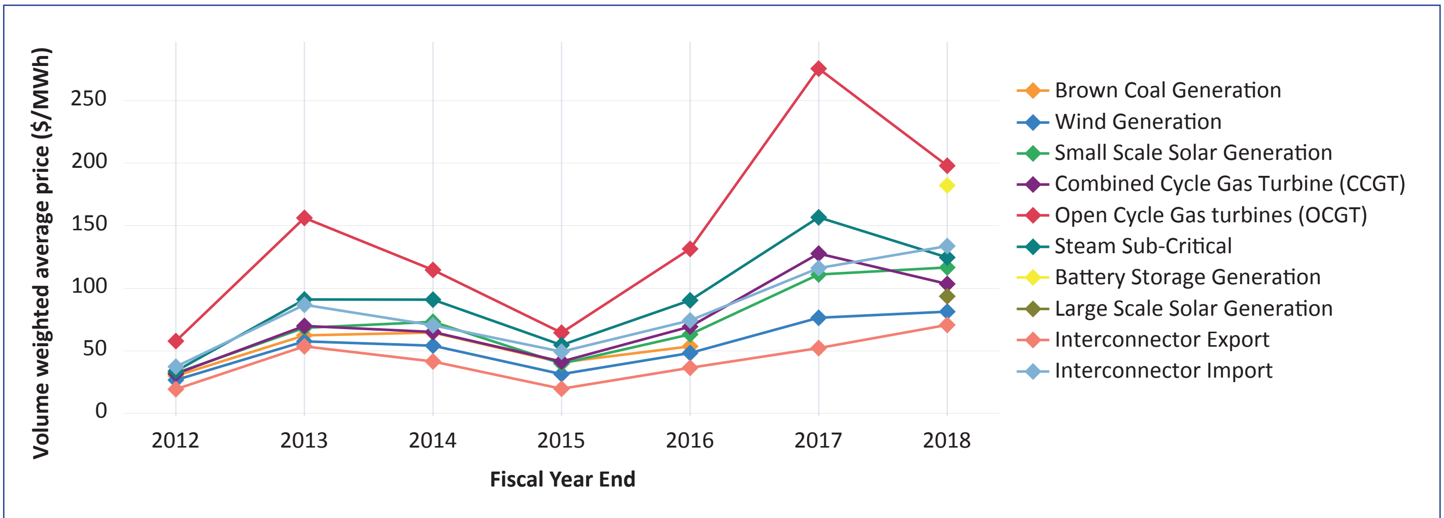

Figure 20: Financial year volume weighted average price by year and generation type[18]

18. Liquid fuel generation, primarily used for peaking generation in SA, has been removed from this plot, this had a volume weighted average of $963/MWh.

4.2 Model and data

4.2.1 Model

Our analysis is based on 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) and Würzburg et al. (2013).

This approach allows us to understand the impact of of renewable generation on wholesale prices in half-hourly intervals. We solve the regression for Equation (1) 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 1 July 2012 to 30 June 2018.

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

Where,

$P_{h,s}$ is the half-hourly spot in 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 6 June 2016, and 460 MW of interconnector capacity until 1 July 2017 to access the 1,600 MW Victorian Hazelwood Power Station through the Haywood interconnector.

$\beta^{0}_{h,m,s}$ 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.

We do not use gas production directly in the model since this correlates with demand as shown by comparing Figure 12 and Figure 16.

4.2.2 Data

The wholesale price used in the model was the half-hourly, South Australian spot price. The data excluded price spikes above $1,000/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.

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[19] and the Australian Clean Energy Regulator (CER), Postcode Data for Small-Scale Installations dataset[20]. The BoM dataset provided the hourly irradiance profiles for each postcode from June 2012 to July 2018. The Python Package, PVlib[21], was used to model 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 CER dataset, provided the monthly installed capacity for each postcode back to June 2012. The hourly generation output for each postcode was 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 up sampled to half-hourly using a linear interpolation between known points.

The half-hourly wind generation data, interconnector export, operational demand and spot price was sourced from NEMReview[22], which accesses the data from AEMO. Daily ex-ante gas price data was provided to us for use in this study by 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.

4.3 Results

We describe here the main results from the model. The model achieved an average in sample R^2 score of 0.54 tested on data from July 2012 to June 2018. The model accurately estimated spot prices. For example in 2018 the average annual price prediced 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 $1,000/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 21 (overleaf) shows the summer and winter wind generation coefficient 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, though the precise value varies around the day, with summer price impacts most significant (but also most variable) around 3–6pm. The wider variability[23] in summer between 3pm and 9pm can be attributed to the higher volatility of wholesale prices in summer.

19. http://www.bom.gov.au/climate/how/newproducts/IDCJAD0111.shtml
20. http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations
21. https://github.com/pvlib/pvlib-python
22. https://app.nemreview.info
23. Variability here is measured as the size of the interval that model estimates, with 95% confidence, that the true value is likely to lie within.

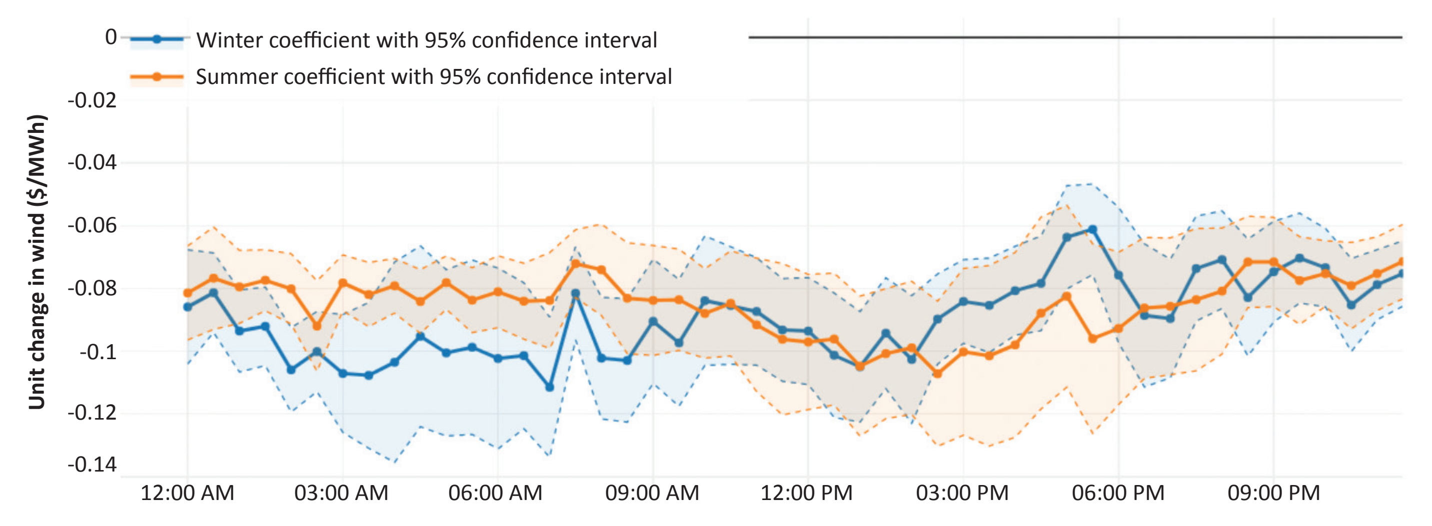

Figure 21: Summer and winter wind generation coefficients

Figure 22 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 the charts earlier), 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 reflects 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 22. 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 less efficient generation to meet the evening peak when solar is not available.

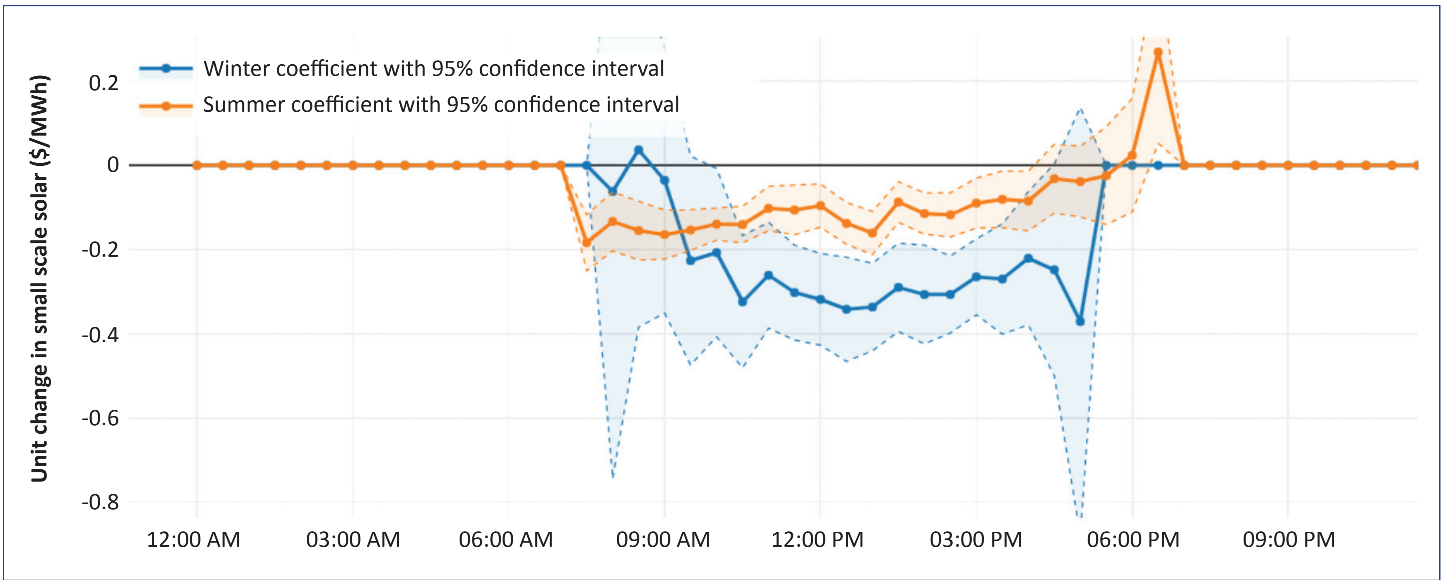

Figure 22: Summer and winter seasonal solar generation coefficients

Figure 23 shows the demand coefficients and the 95% confidence interval. The demand coefficient values for winter are higher before 9am 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[24], as shown in Figure C1. In summer, a smaller increase in OCGT and SUBCRIT occurs during the morning. During the summer daytime, demand coefficient values exceed the winter values, 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 11.

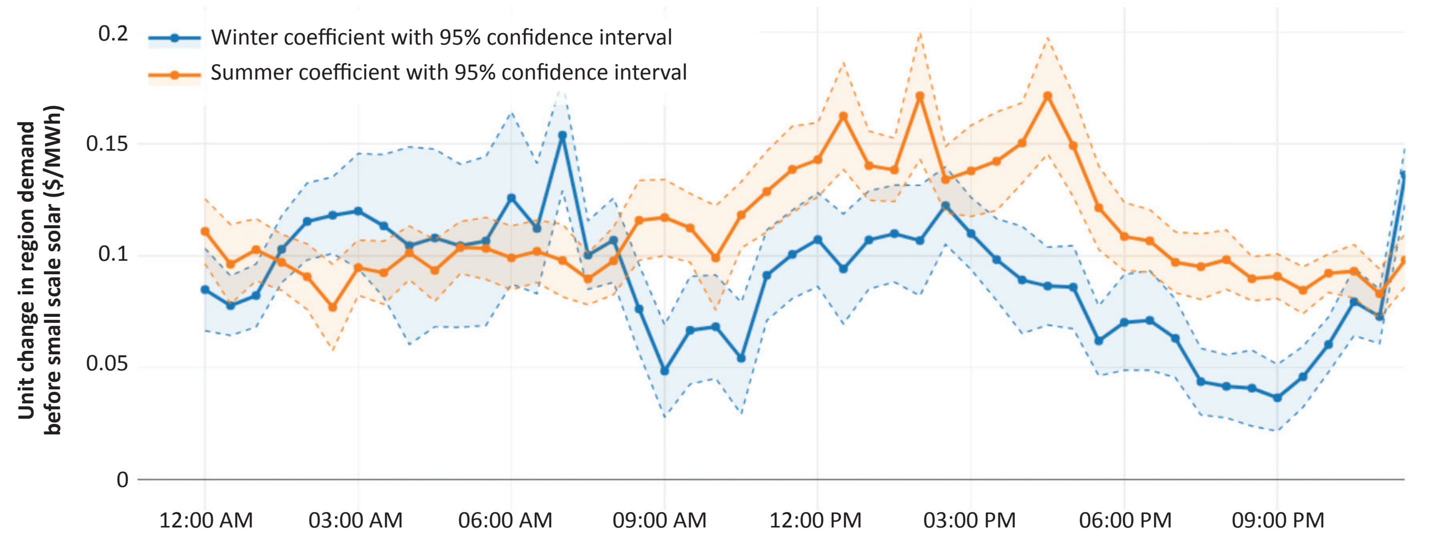

Figure 23: Summer and winter seasonal demand coefficients

Figure 24 (overleaf) shows the impact of daily gas price on hourly wholesale price. The gas price coefficient represents the change in wholesale price due to a one $/GJ incease in daily gas prices. A $3.20/GJ change in gas price, which occurred between 2012 and 2018 would cause an average increase in wholesale price of $14.10 in summer and $26.25 in winter.

The gas price has a major impact on wholesale electricity prices because 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 price influences electricity prices more during hours of higher OCGT and SUBCRIT dispatch following the same trend as Figure C1, 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.

24. 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.

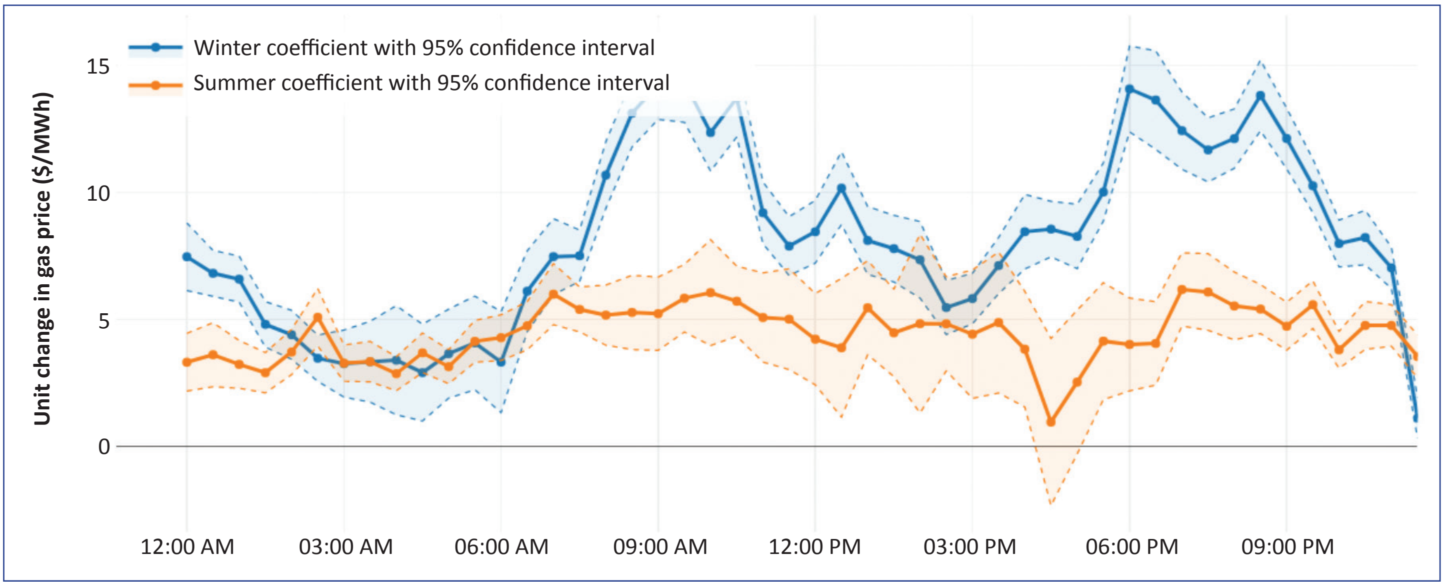

Figure 24: Summer and winter seasonal gas price coefficients.

Figure 25 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/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 $10.6/MWh higher than they otherwise would be[25]. Considering all four seasons, the average effect of both Northern and Hazelwood generation closures has been to increase prices in South Australia by $23.6/MWh from what they otherwise would be.

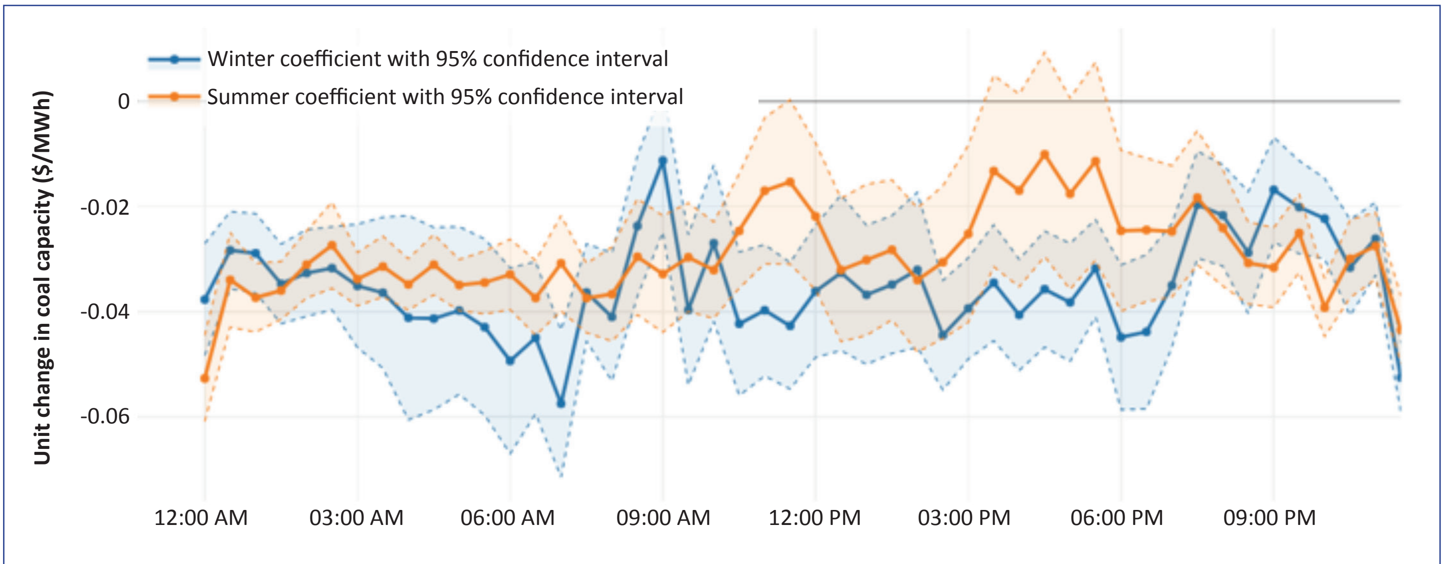

Figure 25: Coal capacity coefficient

25. This assumes that the capacity of the 460MW capacity of the Haywood interconnector was available for dispatch to South Australia.

4.4 Decomposing the spot price in South Australia

To quantify the impact on wholesale electricity prices attributable to gas prices, wind generation, solar generation and demand, we used the regression model to decompose the half-hourly SA spot price into each component. Figure 26 shows that by 2018, the price of meeting SA demand and exports (excluding the other factors) was $65 per MWh. SA's extraordinarily high gas prices explained an increase of $61 per MWh from this base. The 1,110 GWh of solar and 5,550 GWh of wind generation reduced prices by $10/MWh and $28/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 $1,000/MWh.

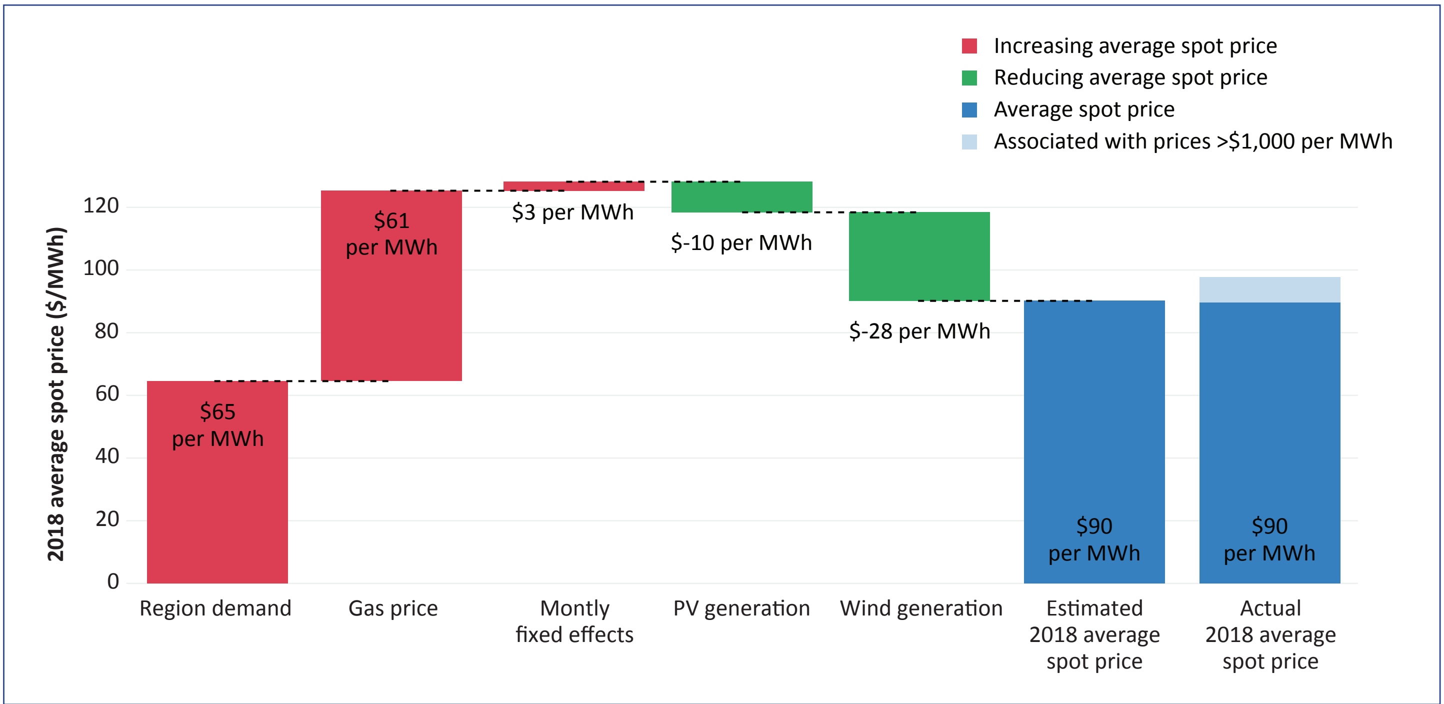

Figure 26: Decomposition of the 2018 average wholesale price in South Australia

We also used the model to explain why the average prices increased from $60[26] per MWh in 2016 to $90 per MWh in 2018. We find that the closure of the coal generators is associated with an average increase of $23.6 per MWh, as discussed above, and the increase in gas prices from $5.5/GJ (in 2013) to $8.5/GJ (in 2018) and also higher production from less efficient gas generation in 2018 relative to 2013 increased prices by $23 per MWh. These price increases were offset by price reductions of $6 per MWh and $10 per MWh attributable to the *increased* production from solar (561 GWh) and wind (1779 GWh) in 2018 compared to 2013. The net of these changes explains the $30 per MWh change in the spot price from 2013 to 2018. The high price reductions from of wind and solar (the increase of 2 340 GWh of additional wind and solar production was able to more than offset the loss of 2,220 GWh of Northern generation) is particularly notable. This high impact is attributable in large part to SA's extreme gas prices and hence the benefit obtained when renewable generation displaces gas generation.

26. The average actual spot price, shown by the blue bar, excludes the effect of extreme prices (greater than $1,000/MWh) which included 329 half-hourly instances over six years or 0.31% of prices. These extreme prices were responsible for increasing the average annual price by $8/MWh in 2018. Consistent with accepted practice, our model excluded the extreme prices greater than $1,000/MWh. This allowed the model to focus on predictable price events, driven by the explanatory variables and not external factors (i.e. generator outages or the exercise of market power). This greatly increases the accuracy of the model (the average R-squared score increased to 0.54 from 0.38 if all prices were included), but does not materially change the value of the coefficients in the regression.

4.5 Subsidising coal generation life extension versus subsidising renewable production

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[27] (around than \$14/tonnes CO2-e). 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 Northern's 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 \$13.5/MWh arise.

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). But the model shows (as discussed in Section 4.3) 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.

By contrast the model shows a \$38/MWh price reduction attributable to renewable production in 2018. This renewable production gave rise to a \$11/MWh subsidy, so the subsidy paid for itself more than three times over.

27. See for example: https://www.afr.com/news/politics/greg-hunt-hails-stunning-result-of-first-carbon-auction-20150423-1mrbyy

5 Discussion

5.1 Literature review

The literature review found studies of the impact of renewables on wholesale electricity prices in electricity markets in Germany, Spain, Denmark, the Netherlands, Ireland, Israel, the UK, Austria, Italy and in the US wholesale markets (California, New England, PJM, Pacific North West, Midwest and Mid Atlantic). None of the studies suggest that renewables had caused wholesale prices to increase. One concluded that renewables had had no impact on wholesale prices and the rest report price reductions of varying size. In Australia, two studies (the most recent using data to June 2013) suggested renewables had reduced prices in the National Electricity Market.

Few of the studies attempt to assess the net impact of renewables (i.e. the extent to which wholesale price reductions were offset by the charge for renewables subsidies). Those studies that did examine it, tended to conclude that the benefit of price reductions was more than offset by the recovery of subsidies from residential customers. In several European countries in particular, large industrial consumers tended to have some level of exemption from these subsidies, and so the net benefit was positive for them.

The analytical techniques used to assess the impact of renewables on wholesale prices have become progressively more sophisticated. One of the recent studies (Bushnell and Novan, 2018), whose approach we have drawn on in this report, drew conclusions not just on average annual impact of renewables, but on the impacts at different times of the day, as we have done, and with seasonal variation.

5.2 International price comparisons

The international price analysis and comparison, though inevitably a study of high level averages, produced understandable and consistent observations. In all the European countries with very high electricity prices and significant renewable production, wholesale prices have fallen as renewable production has increased. In most countries, renewable subsidies charged to households rose as renewables expanded, but in some cases (not most) wholesale prices reduced as much as or more than charges for renewables subsidies rose. Nevertheless the countries with the highest prices – Germany and Denmark – pay by far the highest taxes, unrelated to renewable subsidy. In all countries taxes unrelated to renewables are higher than the charge for the subsidy of renewables.

In the comparison of the Australian and European prices it would be fair to conclude that in Australia's contestable retail markets, consumers are typically paying amongst the highest prices in the world[28]. Certainly, before taxes, Australia's households are paying by far the highest prices in the world. This is not related to renewables subsidies (which are lower in Australia than in the European countries) or taxes (which again are typically much lower than in the European countries). Instead the main reason for higher prices in Australia are higher charges for electricity production and sales, and higher charges for network services.

28. Data provided by the International Energy Agency shows that electricity prices paid by households in other wealthy countries – Canada, the United States, Taiwan, South Korea, Japan – are typically below or far below those in Australia, and so they have not been included in this analysis.

5.3 South Australia analysis

Our analysis of South Australia, consistent with other studies in Australia and elsewhere, concludes that renewable generation reduces wholesale prices. In South Australia in the case of wind generation, the reductions are approximately consistent across the hours of the day. Our model estimates that expanding wind generation will reduce prices at the rate of around $0.09 per MWh, per one MWh of additional wind generation. In the case of solar, almost all of which has been on household roofs, the model estimates wholesale price reduction at the rate of $0.26 per MWh, per one MWh of additional solar production in winter. In summer, additional solar has a smaller impact on prices than in winter. This lower impact can be explained by the typically higher level of gas generation (and hence less efficient and thus more expensive gas production at the margin) that is displaced by solar generation in winter than in summer.

It is also notable that 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 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.

Another notable feature is that despite 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 the 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 greater 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 cost of the 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 $22/MWh in 2013 and $38/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 than in 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, this analysis can inform the response to the question of the contest between coal generation life extension and renewables promotion 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 to revive the depleted Leigh Creek coal mine. In addition to subsidies to revive the plant and mine, the expansion of renewable generation would need to be constrained (to preserve the market for the protected coal generator). Furthermore foregone greenhouse gas emission reductions (that arise by extending Northern's life) would give rise to additional expenditure to ensure that Australia delivers the greenhouse gas emission reductions it has committed to deliver as a signatory to the Paris Agreement.

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[29] (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.

In addition, assuming the average price reduction associated with renewables from the model ($38/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.

By contrast, as discussed earlier, the analysis shows renewables reduce 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.

It might be suggested that this analysis ignores the reliability benefit associated with dispatchable coal generation rather than variable renewables. But the model shows the impact of coal closure and renewable expansion as expressed in the actual market prices. The argument that there is a reliability value that is not currently reflected in South Australia's prices therefore needs to establish that those prices are wrong, specifically that they have failed to reflect the value of reliability. The evidence does not seem to support this. Specifically, the volume-weighted average prices received by different production technologies does not suggest that dispatchable production has become more valuable in South Australia as the proportion of renewable production has increased.

It might alternatively be suggested that in future with an even higher share of variable renewable production, dispatchable generation will become more valuable. This is a more plausible argument and, if correct, it can be expected to be reflected in prices: plentiful supply at times of plentiful wind or sun can be expected to result in lower prices received by renewable producers. Conversely, production from stored resources – whether they be batteries, gas or coal generation or hydro – will become more valuable if they can quickly respond to higher residual demand when renewable resources are not plentiful. The argument that there is an unpriced reliability value associated with dispatchable generation must assume that market prices in the future will fail to reflect this, or that market participants will fail to respond to price changes. Considering the investment in storage and its substitutes in South Australia, and elsewhere, the evidence does not seem to support these assumptions.

29. See for example: https://www.afr.com/news/politics/greg-hunt-hails-stunning-result-of-first-carbon-auction-20150423-1mrbyy

6 Conclusions

The analysis in this report supports the following conclusions:

1. Household electricity prices have risen in those European countries that have increased renewable generation. However increased renewable generation has also reduced wholesale prices in those countries. For households in some countries, this wholesale price reduction has been higher than the cost of the renewable subsidies they bear, although this does not seem to be the case generally. Renewable subsidies, however, only account for a relatively small part of households' electricity bills even in those countries with the highest renewables subsidies. Taxes that have nothing to do with renewables are typically a bigger proportion of household bills than renewable subsidies. It is the increase in these taxes that in most cases explain higher household prices.
2. Households in Australia's contestable retail markets pay amongst the highest prices in the developed world. Before taxes, prices in most of Australia are higher than in the highest in Europe. Renewables subsidies in Australia do not explain this: such subsidies are lower in Australia than in the European countries. Rather, higher prices in Australia are explained by higher network charges and much higher production and retail charges.
3. Gas prices are by far the most significant factor explaining South Australia's high wholesale prices. Over the period from 2013 to 2018, increases in wind and solar production have reduced wholesale prices more than coal closure in South Australia has raised them.
4. The price reductions associated with renewable generation in South Australia are more than three times the value of the subsidy associated with that renewable generation.
5. Coal generation closure raised prices, but these were off-set by reductions attributable to 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 coal mine, electricity consumers would have been worse off to the extent that they would be required to bear the cost of foregone emission reductions.

Appendix A: Non-household price comparisons

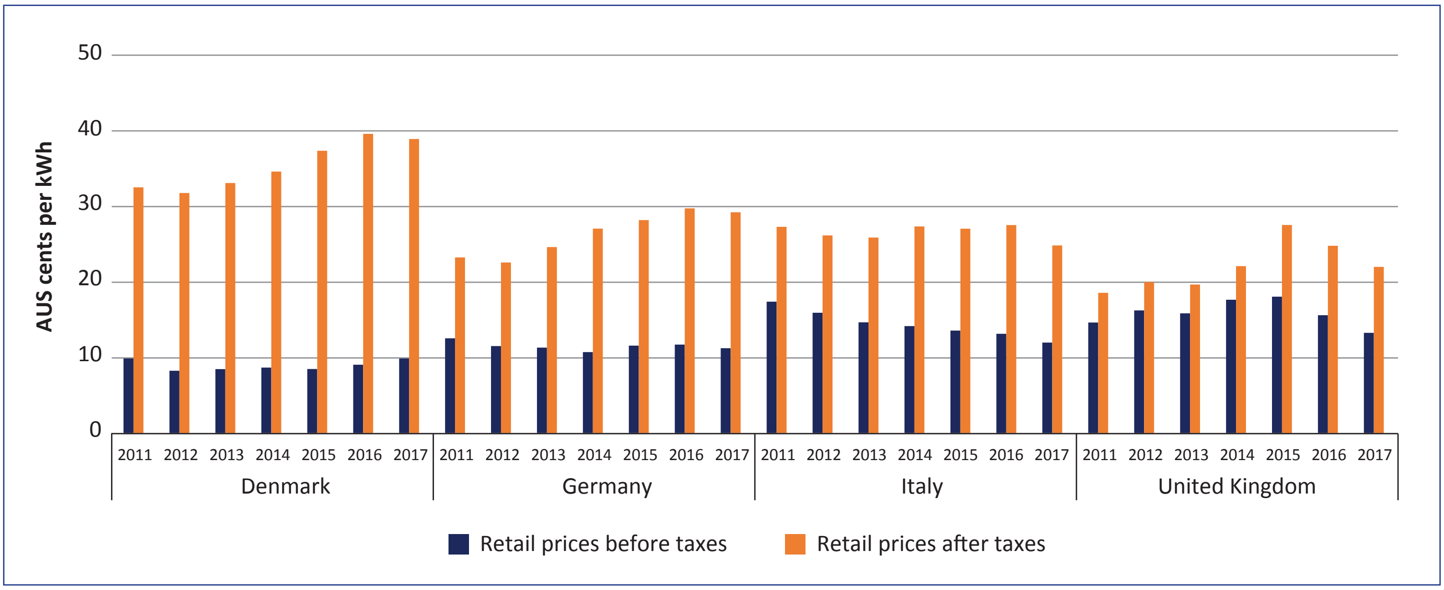

Figure A1: Non-household electricity retail prices

Source: Eurostat. Electricity prices are for consumption Band IC (500 MWh < Consumption < 2,000 MWh).

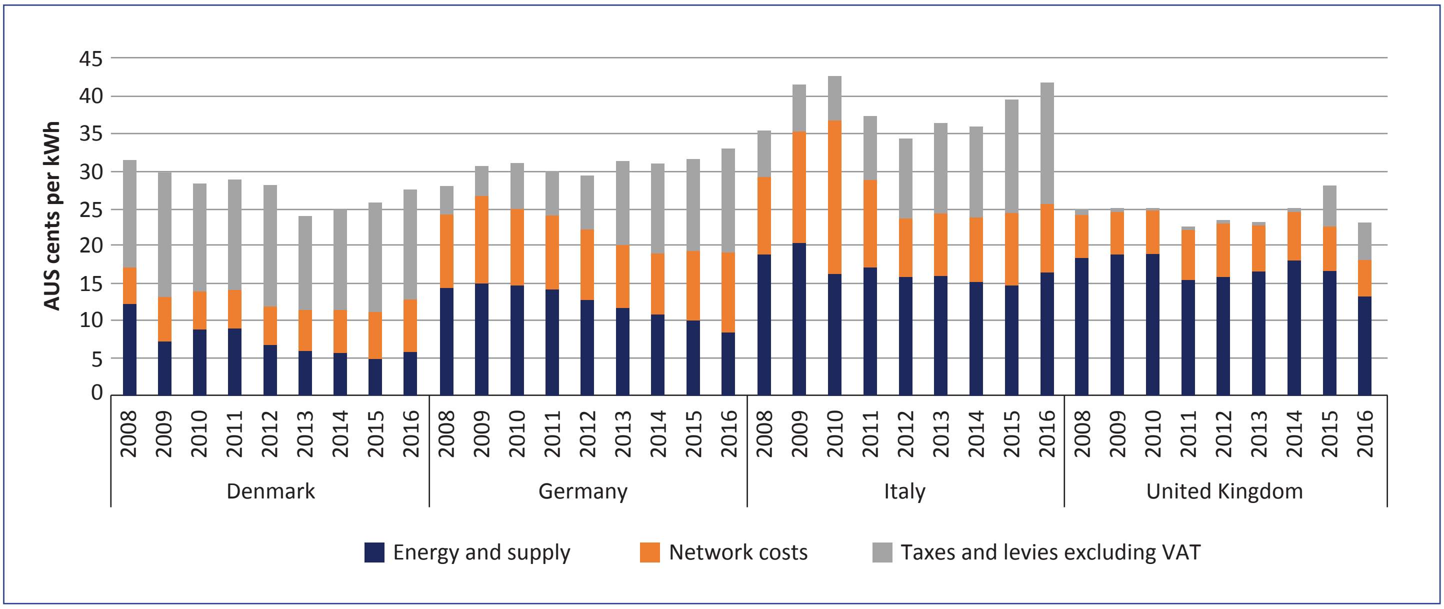

Figure A2: Electricity price components for non-household customers

Source: Eurostat (https://ec.europa.eu/eurostat) Electricity prices are for consumption Band IA (Consumption less than 20 MWh).

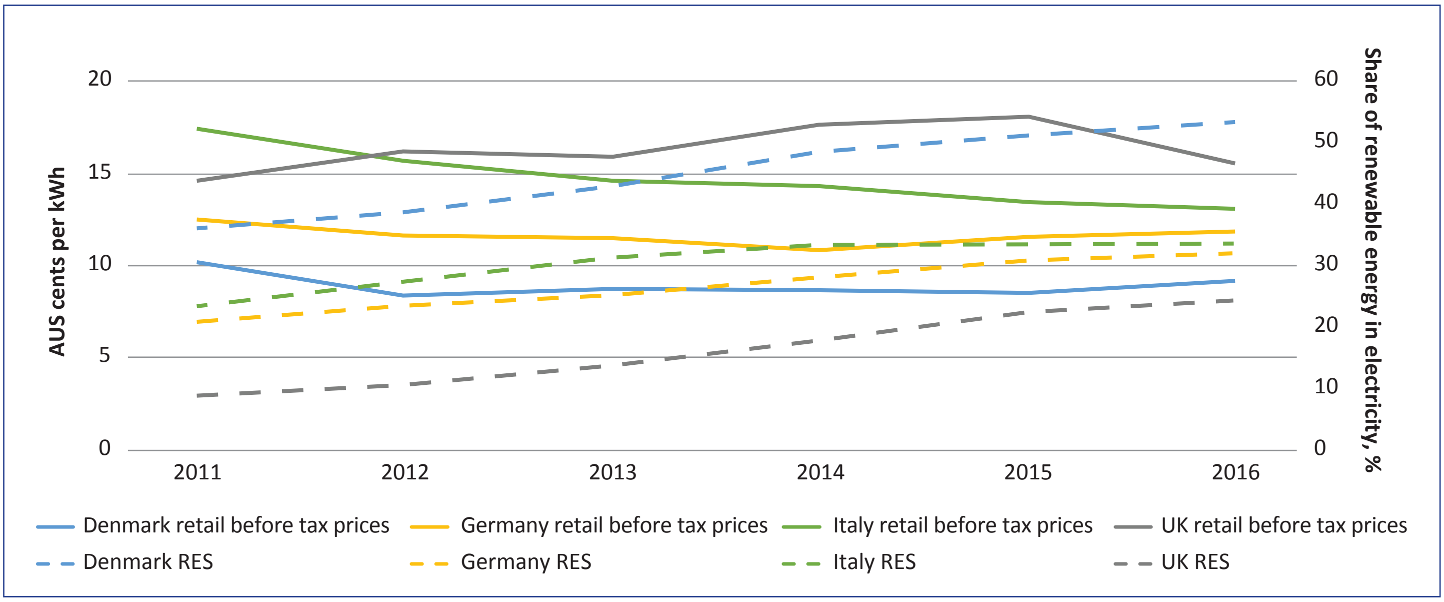

Figure A3: Renewable energy shares vs retail before tax prices, non-household

Source: Eurostat (https://ec.europa.eu/eurostat) Electricity prices are for consumption Band IA (Consumption less than 20 MWh).

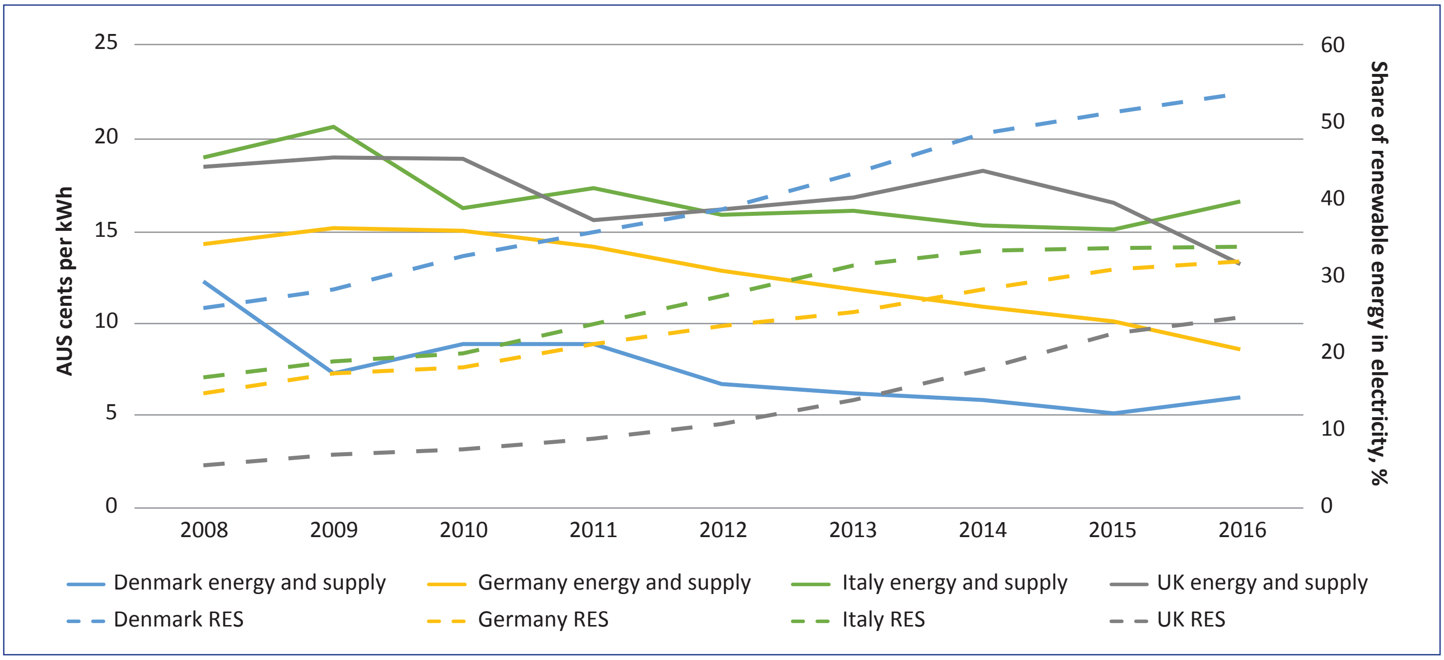

Figure A4: Renewable energy shares vs energy and supply prices, non-household

Source: Eurostat (https://ec.europa.eu/eurostat) Electricity prices are for consumption Band IA (Consumption less than 20 MWh).

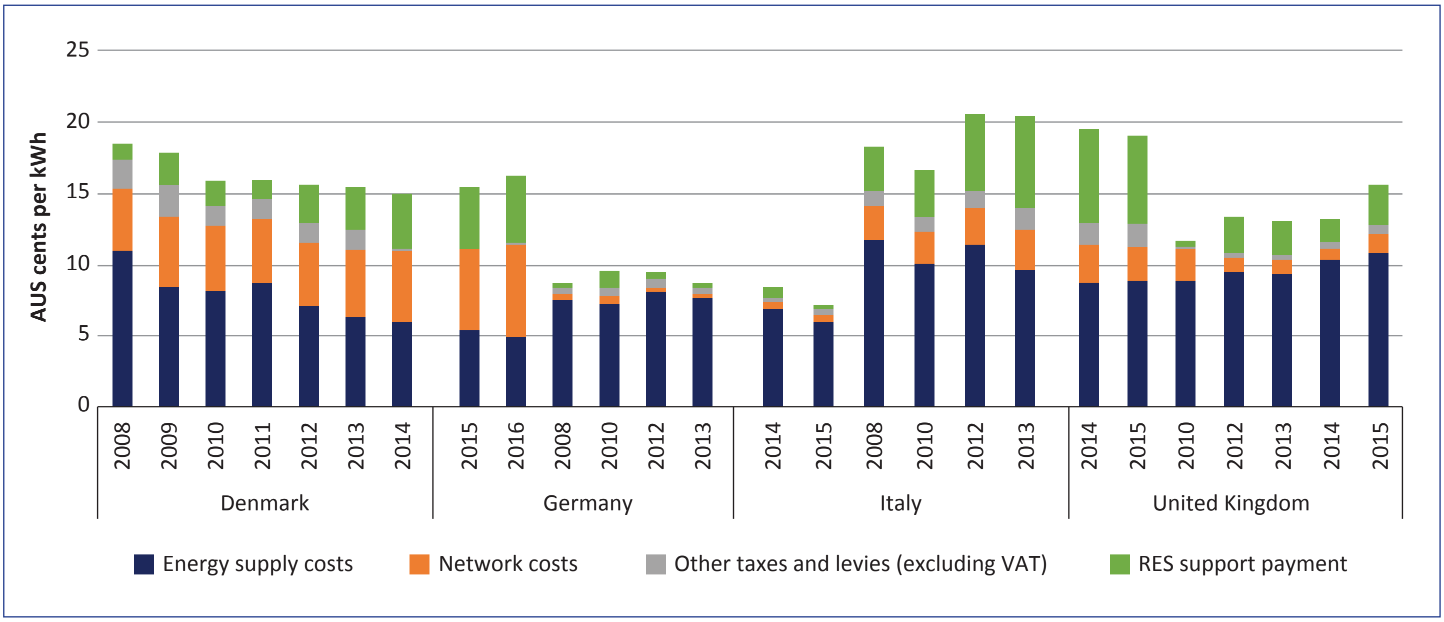

Figure A5: Industry electricity breakdown

Source: For Germany, Italy, and UK data source is CEPS, https://www.ceps.eu/publications/composition-and-drivers-energy-prices-and-costs-case-studies-selected-energy-intensive. Germany, Italy, and UK retail energy prices are for five energy-intensive sectors including steel, aluminium, wall and floor tiles, bricks and roof tiles, and refineries.

Danish data is re-structured to comply with the CEPS data as follows: Retail cost is labelled as energy and supply cost. Network tariff, system and regional tariff, and transmission is grouped into network costs.

Prices are in 2017 Australian Dollar; it is adjusted for inflation by using the OECD (http://www.oecd.org) published Consumer Price Index. The exchange rates for converting Euro and Danish Krone to AUD are obtained from OECD.

Appendix B: Electricity generation in the National Electricity Market

The following table lists the main generation types in the national Electricity Market (NEM), together with a simplified summary of their relevant cost and technical characteristics, the current (September 2018) number of individual plants (power stations), their share of total installed capacity as at September 2018, and their share of total electricity supplied in the year to August 2018. The total size of the NEM system is defined by the total installed capacity at that date, which was approximately 48 GW, and total electrical energy sent out by these generators during the preceding year, which was approximately 185 TWh.

Table B1

Generation type	Relevant cost characteristics	Relevant technical characteristics	Number	Share of capacity	Share of supply
Black coal fuelled steam	High capital, moderate operating	Dispatchable, inflexible	13	34%	55%
Brown coal (lignite) fuelled steam	Higher capital, lower operating	Dispatchable, inflexible	3	11%	18%
Gas fuelled steam	Old (amortised) capital, high operating	Dispatchable, inflexible	3	4%	2%
Combined cycle gas turbine	Moderate capital, high operating	Dispatchable, moderately flexible	10	7%	6%
Open cycle gas turbine	Low capital, very high operating	Dispatchable, very flexible	23	11%	2%
Hydro	Very high capital, very low operating	Dispatchable, very flexible, but “fuel” resource constrained	Many	16%	8%
Wind	Very high capital, very low operating	Not dispatchable, inherently variable	Many, rapidly growing	13%	8%
Solar PV	Very high capital, very low operating	Not dispatchable, inherently variable	Some, rapidly growing	3%	1%

Appendix C: Gas generation in South Australia

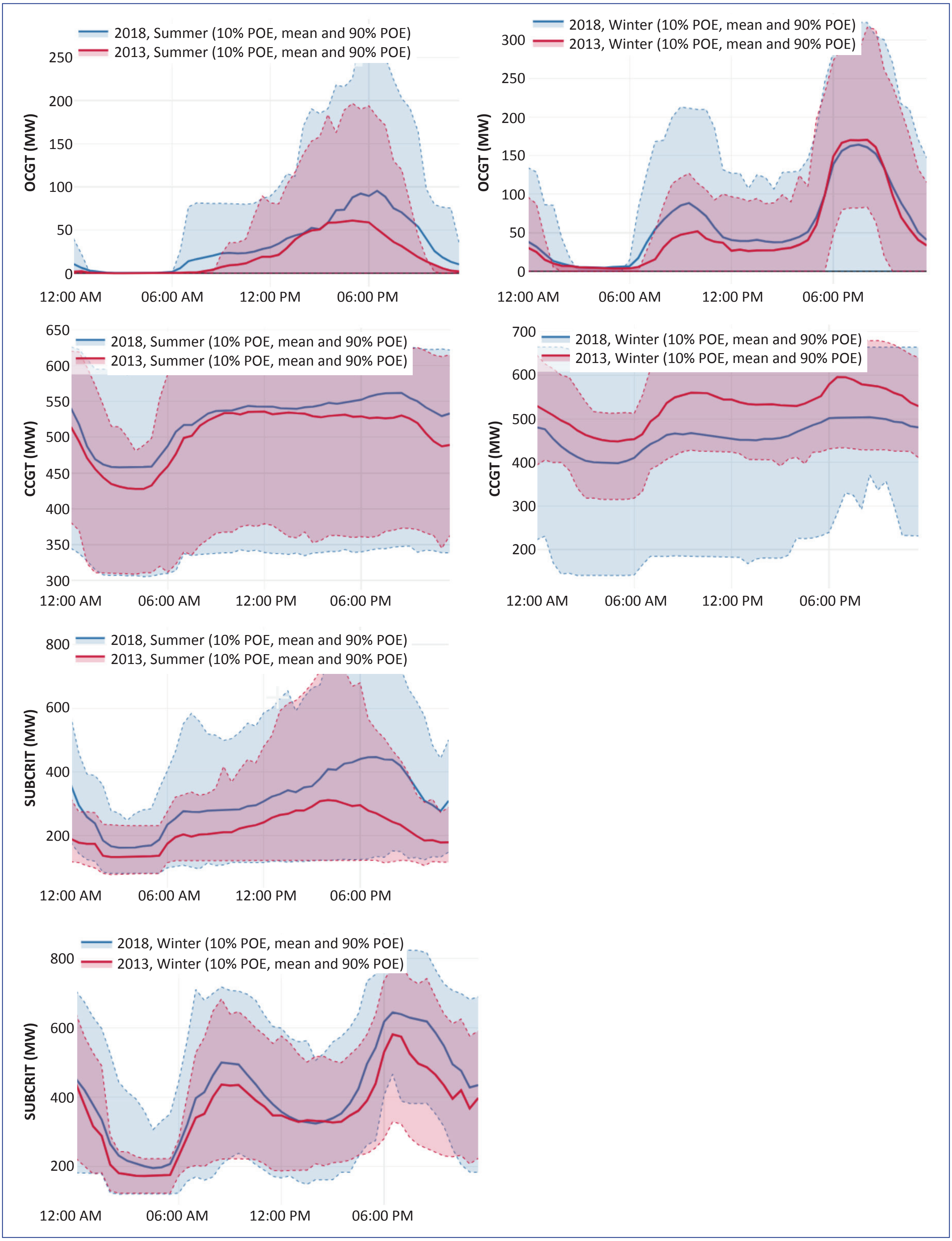

Figure C1: Summer and winter gas generation in South Australia

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