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Is there a value for "dispatchability" in the NEM? Yes

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It has been argued there is currently no value for "dispatchability" (or dispatchability premium) in the national electricity market (NEM). While a value for dispatchability is not as transparent in the NEM as it is in other electricity markets, it does exist. We calculate this premium as the difference between the dispatch-weighted prices received by non-dispatchable and dispatchable generators. Using South Australia as an example, we calculate the dispatchability premium has averaged around 70 per cent since 2016, with this premium more than doubling between 2014 and 2019.

Keywords: dispatchability, dispatch-weighted price, energy-only market, National Electricity Market, variable renewables
JEL Codes: D40; D47; O13; Q40; Q41; Q42; Q50

1. Introduction

Australia's national electricity market (NEM) commenced in December 1998, inheriting a high-quality and oversupplied stock of monopoly-built utility-scale plant at inception, due solely to significant excess supply of high-capacity factor plant. Simshauser (2019) estimated this excess capacity to be around 4.1 GW, or 20 per cent, of total baseload capacity installed in 1998.[1] In contrast, there was a deficit of almost 20 per cent (around 1,500MW) of intermediate and peaking capacity, compared to the optimal amount capacity estimated to be required across the NEM (Simshauser, 2019).

Figure 1 contains the following key trends in relation to the entry and exit of utility-scale (defined as capacity of 100 kW or greater) generation plant since the NEM's commencement:

1. The entry of more than 6,000 MW of gas-fired plant (both intermediate and peaking plant) over the decade to 2009, with more than half of this capacity (3,600 MW) entering in 2008 and 2009. Rai and Nelson (2019) note this investment occurred in response to policy signals[2] and wholesale electricity price spikes of 2007-2008 due to Australia's east coast millennial drought.[3] This entry more than filled the estimated shortage of peaking and intermediate capacity at NEM-start, and meant the 2007-2008 wholesale price spikes were only transitory.

2. The exit of high-capacity factor (primarily, coal-fired) plant over a relatively short three-year period (2014-2017); between June 2014 and June 2017 over 4.1 GW of coal-fired plant exited the NEM. This exit of plant at-scale unwound all the excess capacity in place at NEM-start, and occurred suddenly and unexpectedly, partly contributing to the

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[1] This amount of excess baseload capacity meant overall excess capacity in the NEM was almost 10 per cent.

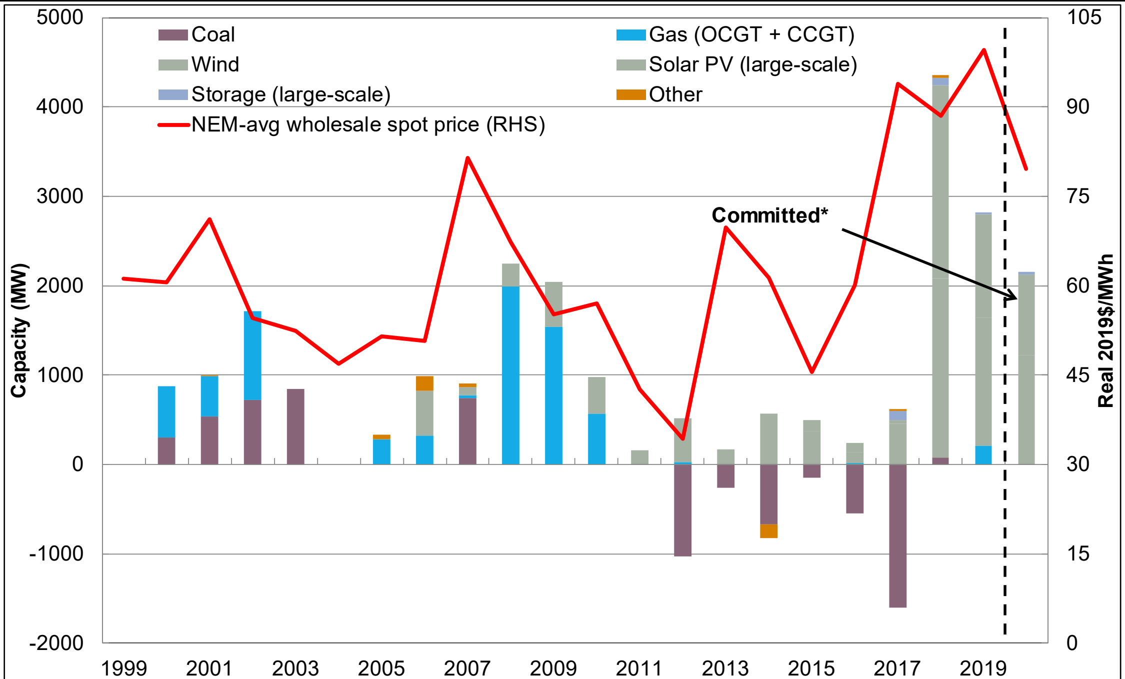
[2] These policy signals were the Queensland 18% Gas Scheme and the NSW Greenhouse Gas Abatement Scheme. The Queensland scheme commenced in January 2005, and required electricity retailers to source 18 percent of their Queensland electricity from gas-fired generation. It was reported that, in the first year of the scheme, over 1600 MW of generation capacity (across ten gas-fired power stations) was accredited (Queensland Government, 2007).

[3] In addition to adverse effects on hydro plant, the drought forced some coal-fired generators to mothball units due to cooling water shortages, with urban drinking water being prioritised from affected dams (Simshauser, 2019).

doubling in wholesale prices across the NEM between 2016 and 2018 (Rai and Nelson, 2019).

3. The entry of significant volumes of largely non-dispatchable variable renewable energy (VRE) plant such as wind and solar PV.[4] Between July 2012 and June 2019, over 7,500MW of utility-scale wind and solar PV entered the NEM.

Figure 1: Net entry and exit of utility-scale plant across the NEM, by financial year[5]



*As at 1 October 2019. 'Committed' includes plant that may enter the NEM after July 2020. The figure excludes Snowy 2.0

Source: Authors calculations based on data from AEMO and from the AER.

Rai and Nelson (2019) note that there has been a lack of entry of dispatchable plant[6] in the NEM in response to the wholesale price spikes in 2017, in contrast to the 2007-2008 price spikes. This lack of entry has resulted in wholesale prices remaining at elevated levels over the 2017-2019 period, and well above 2007-2008 prices, though prices have moderated somewhat since July 2019 in response to the increased output from VRE plant installed between 2017 and 2019.

Given the lack of entry of dispatchable plant to replace the exit of thermal plant, this has raised questions about whether the NEM's existing wholesale market design appropriately values dispatchability (for example, see AEMO (2019, 2017)). Various studies (such as Rai *et al.*, (2019); Rai and Nelson (2019); and Simshauser (2019)) have attributed the lack of entry of dispatchable plant to a combination of:

- uncertainty on carbon emissions policy, an especially pertinent issue for gas-fired generation which may be stranded under deeper decarbonisation targets. Gas has traditionally been viewed as the 'transitional fuel' for the NEM's decarbonisation
- higher gas prices and the effects of the drought, which have increased the long-run marginal costs (LRMCs) of prospective gas-fired and run-of-the-river hydro plant,

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[4] While VRE output can be controlled down, the technical characteristics of existing VRE plant in the NEM means VRE output cannot be controlled up (i.e.. increased). Consequently, VRE output is considered non-dispatchable.

[5] Prices weighted by volume in each region, and then across regions. Financial year refers to the year ended 30 June.

[6] While "dispatchability" does not have a universal meaning, it is commonly considered as the extent to which the resource (i.e. demand or supply resource) can be relied on to 'follow a target' in relation to its load or generation. "Dispatchability" therefore incorporates notions of controllability and flexibility

respectively, and meant prices need to be sustained at levels higher than would otherwise be the case, in order for LRMCs to be adequately recovered

- changes in the profile of electricity demand due to the rapid uptake of small- and utility-scale VRE plant. This requires a large amount of VRE-complementary plant (namely, fast-start, fast-response, lower-capacity factor, plant), as opposed to slow-start, high-capacity factor plant
- technology-induced stranding risk, in particular the risk that batteries may become cheaper than peaking plant (gas-fired or pumped hydro). In California, 4-hour batteries are increasingly replacing gas peaking plant as these plant approach major capital expenditures (associated with extensions of technical life). 6-hour storage also poses stranding risk to more intermediate/less peaking plant (Spector, 2019), and
- the entry of Snowy 2.0, a 2000MW pumped hydro plant in NSW, during the mid-to-late 2020s, which would compete directly with other forms of fast-start dispatchable plant. The mid-to-late 2020s timeframe is, unfortunately, long enough to elongate otherwise-transitory price spikes (such as in Figure 1), but short enough to make stranding risk a material issue for prospective entrants.

A lack of a dispatchability "premium" does not feature within these factors because the NEM *does* put a value on being dispatchable. This value (or premium) can be inferred by comparing the dispatch-weighted price (DWP) received by dispatchable generators such as coal, gas and hydro, against the DWP received by VRE generators. A DWP is the volume-weighted price received by a generator. The uniform-price auction feature of the NEM means that each generator that generates during a particular five-minute interval is paid the same price (ignoring electrical losses).[7] Therefore, differences in DWPs across generators reflects the *time* at which each generator generates its output.

In contrast, some other electricity markets have pay-as-bid – for example, California (see Kahn *et al.,* 2001), and the United Kingdom (see Federico and Rahman, 2003) – rather than uniform-price auctions. This, and other forms of generator discriminatory-pricing designs, enable a more direct assessment of the value for dispatchability than is the case in the NEM.

The correlation between a generator's output and electricity demand indicate the extent to which that generator's DWP is linked to either the time-weighted spot price or the demand-weighted spot price.[8] In particular:

- the higher (lower) the correlation between a generator's output and demand, the closer (further) is its DWP with demand-weighted spot prices. That is, the higher (lower) the correlation, the higher (lower) the DWP[9]
- when a generator's output is uncorrelated with electricity demand, its DWP is equal to the settlement price, and therefore is lower than the demand-weighted price

The time-weighted price is the DWP received by a generator with a constant level of output. This generator could, for example, be a high-capacity factor plant (for example, brown coal-fired

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[7] In the NEM, price differentials between coincident-output generators do occur, where the price differences reflect electrical losses associated with the output of individual generators. That is, generators located in areas with higher export losses receive a lower price than coincident-output generators located in areas with lower export losses. Currently, there are no congestion-induced price differentials between coincident-output generators in the NEM, often resulting in inefficient dispatch. Allowing congestion-induced price differentials has been recommended since NEM-start, most recently in the AEMC's current review of transmission investment frameworks (AEMC, 2019).

[8] In the NEM, the time-weighted spot price is the price used for making payments to electricity generators (i.e. it is the settlement price). There is one settlement price for each 30-minute trading interval, and this price is the equally-weighted average of the six five-minute spot prices within that trading interval. Equally-averaging across a period of time (for example, a quarter or a year) gives a settlement spot price for that period. The demand-weighted spot price is the settlement spot price for a time period weighted by demand in each of the trading intervals for that time period.

[9] This point is not always true: a peaking plant whose output is zero except for a few hours a year when its output is 100 per cent (at or near the price cap) will have a very low positive correlation with demand/price.

plant[10] or a nuclear plant) that is technically or economically unable to adjust its output over time. While the constant-output assumption associated with time-weighted prices is unrealistic, as all generators have some ability to vary output, time-weighted prices nonetheless serve as a useful price comparison with other DWPs.

The demand-weighted price is the DWP received by a generator that is able to positively correlate its output with demand, ramping up and down as demand fluctuates. There are two types of demand-weighted prices:

1. prices paid to generators that supply operational demand – operational demand is demand supplied by utility-scale dispatchable and non-dispatchable (i.e. VRE) generators. That is, end-consumer electricity demand less any behind-the-meter generation
2. prices paid to generators that supply *residual* demand – residual demand is defined in Rai *et al*. (2019) as operational demand less supply from utility-scale VRE generators.

In this paper, we define "demand-weighted price" as the price paid to generators that supply residual demand as this type of demand is, by definition, met by dispatchable generators (for example, coal plant, gas-fired peaking plant or pumped hydro). These generators, especially fast-start and flexible generators, help 'firm' VRE generation, and therefore we use the phrase "firming" price to refer to the DWP received by these generators. The firming price therefore provides direct estimates of the value of being both *dispatchable and flexible*.

Therefore, differences between these three prices (i.e. time-weighted prices, firming prices, and DWPs received by non-dispatchable plant like wind and solar PV) provide information about:

- the premium for being flexible and dispatchable, vis-à-vis being *inflexible* and dispatchable (i.e. the difference between firming prices and time-weighed prices), and
- the premium for being dispatchable relative to not being dispatchable (i.e. the difference between time- and dispatch-weighed prices, for non-dispatchable plant).

It is important to note that while the quantitative analysis in section 2 focuses on spot prices, forward prices are as, if not more, important for generators. New-entrant generators typically choose to contract some or all of their capacity in order to de-risk the investment and thereby lower their costs of capital. This is especially the case for VRE generators for whom the majority of their lifecycle costs are incurred upfront before any revenue is received.[11]

2. The dispatchability premium in the NEM: the case of South Australia

2.1 Increasing VRE penetration in South Australia

Over the year to July 2007, utility-scale wind and solar PV comprised less than 1 per cent of NEM generation, compared to around 12½ per cent over the year to July 2019 (AER, 2019). In South Australia (S.A.), the NEM region with the highest penetration of VRE generation (principally, wind farms), the share of utility-scale VRE generation was over 50 per cent over 2018/19, compared to 9 per cent over 2007/08 (Figure 2).

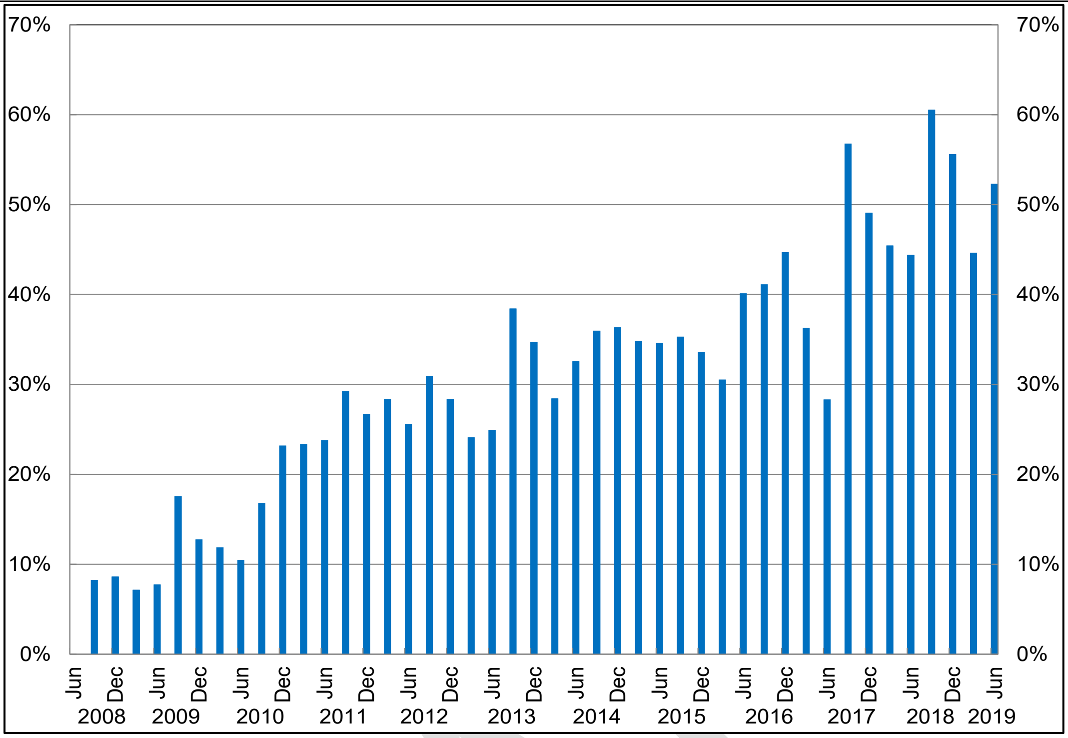
S.A. has one of the highest VRE penetrations globally, exceeded only by Denmark (Figure 3).[12]

[10] Black coal-fired plants are more flexible than brown coal-fired plants. For example, coal plant in Queensland and New South Wales – all black coal-fired output – can operate between 40 per cent and 100 per cent of their maximum output and can ramp in a few hours. By contrast, Victorian coal plant, all brown-coal fired, operate between 70 per cent and 100 per cent, with ramps over more hours than black coal plant.

[11] To date, the vast bulk of VRE generators have contracted all of their output in the form of generation-following hedges like power purchase agreements. While we focus on spot prices, a similar price premium applies for forward prices; for example, over 2017, forward time-weighted prices were estimated to be 33 per cent above South Australian wind farms' forward prices (AEMC, 2017).

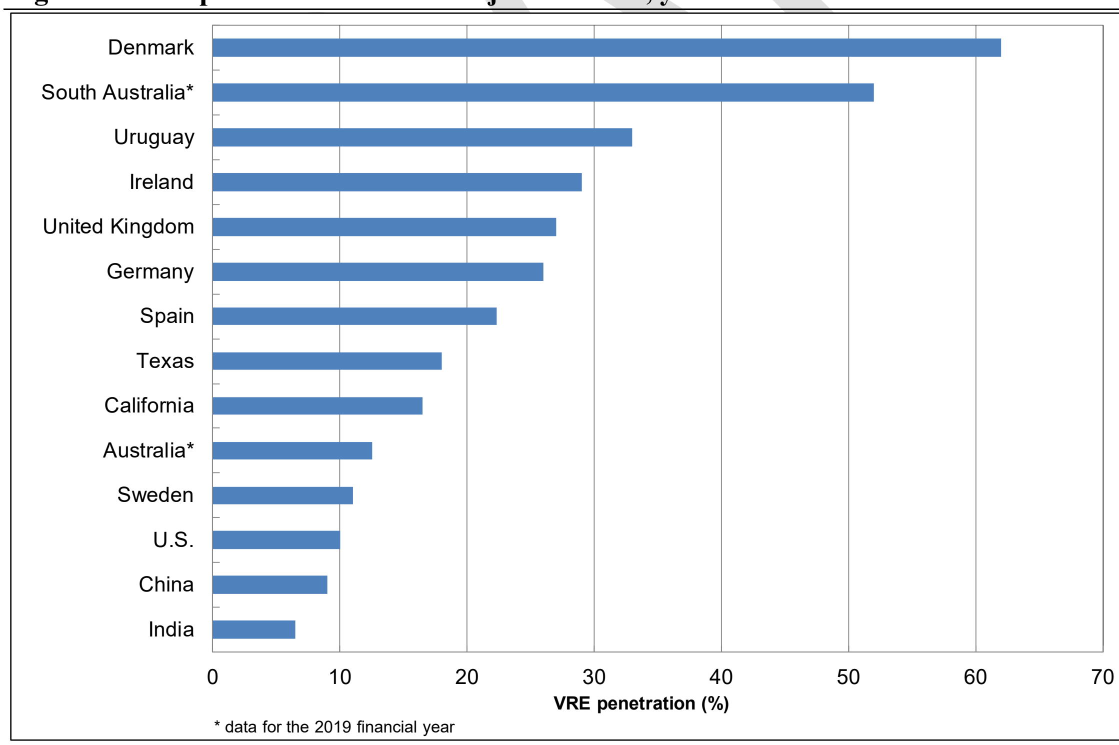
[12] Figure 3 excludes small-scale VRE (systems sizes of less than 100kW). If this were included, South Australia's VRE penetration rate is around 60 per cent, in excess of Denmark's (small- and utility-scale) VRE penetration rate.

Figure 2: Utility-scale VRE penetration in South Australia, by quarter



Source: Authors' analysis of AEMO data.

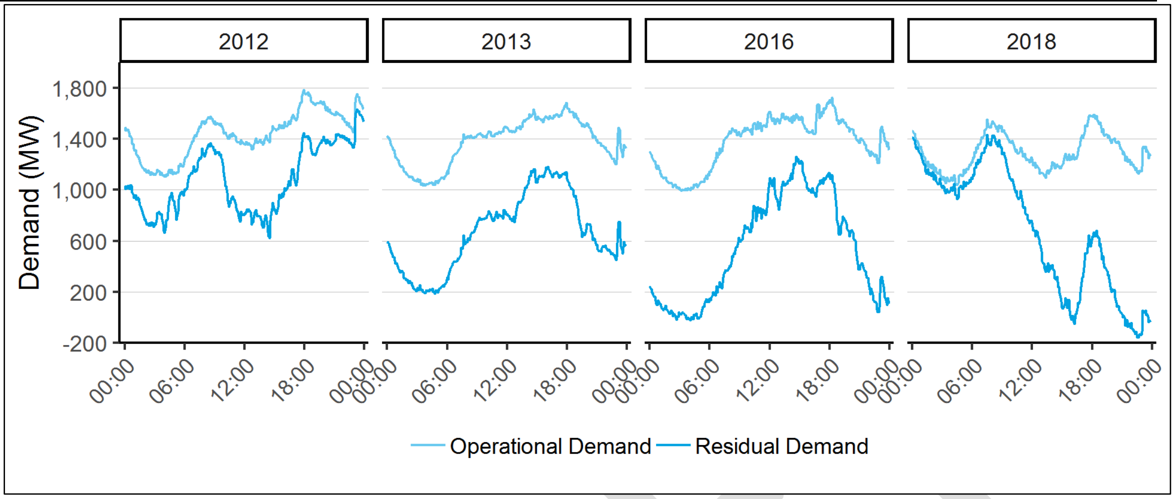
Figure 3: VRE penetration in selected jurisdictions, year to 30 June 2018



Sources: Authors' calculations based on data from AER (2019) and IEA (2019)

As noted by Rai *et al.* (2019), growing VRE penetration, in combination with flat electricity demand growth, has made *residual* electricity demand more volatile in South Australia, on both intra- and inter-day dimensions. Figure 4 illustrates how South Australian residual demand has changed over time by considering the outcomes on a single day of the year (9 May) for different years. In particular, intra-day residual demand has become significantly more volatile since 2012, compared to the intra- and inter-day volatility of operational demand, due to the growth in utility-scale VRE penetration over this period (Figure 2).

Figure 4: Daily operational and residual demand in South Australia, 9 May by year



Source: Rai *et al.* (2019)

Since June 2016, residual demand in South Australia has been met by gas-fired generation and imports from Victoria, following the closure of the last coal-fired plant in South Australia in May 2016. Due to Victoria and South Australia having correlated weather patterns, as well as Victoria's VRE penetration being barely one-quarter of South Australia's[13], imports from Victoria are comprised mostly of coal- and gas-fired generation, rather than of VRE generation.

As also noted by Rai *et al.* (2019), another way to observe changes in residual demand is to examine various points on the residual demand frequency distribution. Figure 5 shows monthly residual demand in South Australia at the 5th, 50th and 95th percentiles, revealing that, since 2010, the residual demand distribution has:

- shifted to the left i.e. residual demand has fallen, consistent with Figure 4
- become wider – residual demand at the 5th percentile has fallen by 100 per cent – from 1000 MW to around zero – exceeding the 40 per cent decline in residual demand at the 95th percentile (from 2,500 MW to 1,000 MW). South Australian residual demand is increasingly zero and even negative, even at the 5th percentile. This means *minimum* residual demand is even lower, and
- become peakier – residual demand at the 95th percentile has not fallen by as much as residual demand at the 50th or 5th percentiles.

The greater intra- and inter-day volatility in residual demand, coupled with the growing peakiness of residual demand, suggests an increasing value of generation plant capable of meeting this volatile demand. Estimates of this premium are shown in the next section.

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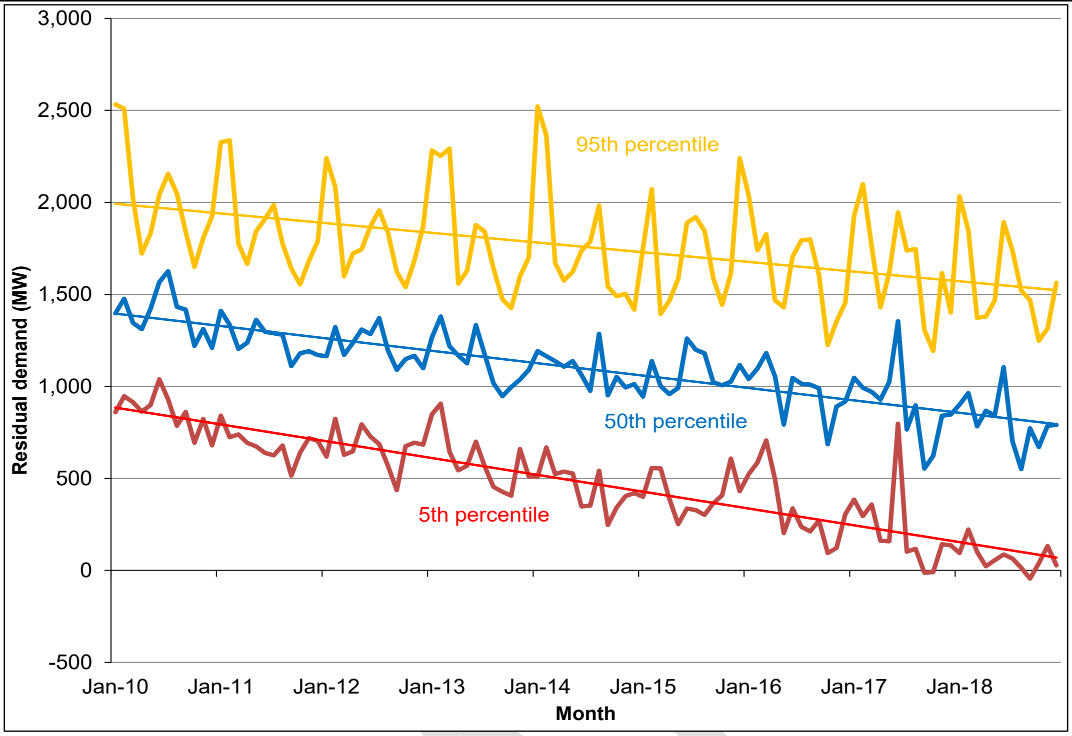
[13] Over the 2019 financial year, Victoria's VRE penetration was 12 per cent (AER, 2019). By contrast, South Australia's VRE penetration rate was 52 per cent (Figure 3).

Figure 5: Median, 5th and 95th percentile of monthly South Australian residual demand



Source: Rai *et al.* (2019)

2.2 Correlation between wind output and operational demand

In addition to wind farms' variable-output nature, the second characteristic of South Australian wind generators is the negative correlation between wind output and operational demand. Between January 2013 and December 2018, correlation ranged from -0.36 to -0.08 (Table 1).[14]

Table 1: Correlation between wind output and operational demand in South Australia

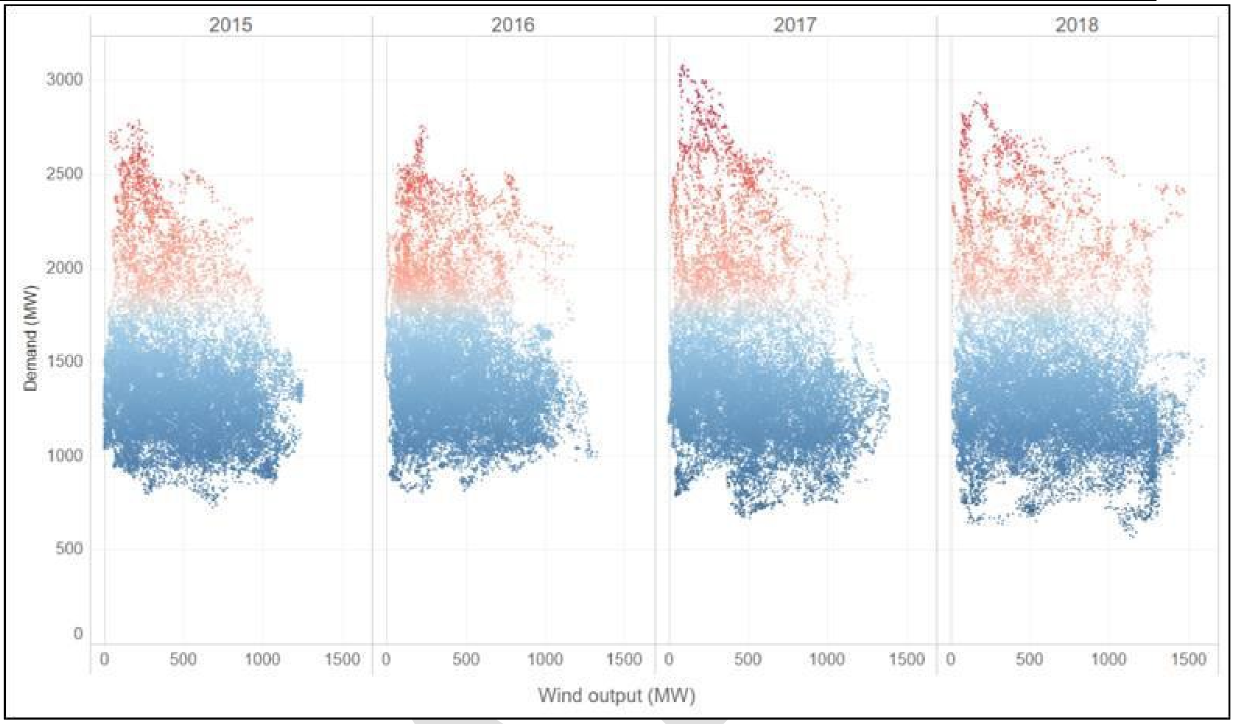
Calendar year	Q1	Q2	Q3	Q4
2013	-0.25	-0.36	-0.26	-0.27
2014	-0.25	-0.12	-0.24	-0.23
2015	-0.19	-0.31	-0.20	-0.15
2016	-0.17	-0.16	-0.18	-0.15
2017	-0.24	-0.31	-0.25	-0.08
2018	-0.18	-0.19	-0.25	-0.18

Source: Authors' calculations based on data from AEMO

Focusing on the first quarter of each calendar year (i.e. 1 January – 31 March) – the period when electricity demand in the NEM is typically the highest – it is observed that high demand typically coincides with low wind output (Figure 6). Put differently, the system tends to be becalmed on the hottest days when demand reaches its highest levels.

[14] The correlation between wind output and residual demand is even more negative, an expected result given the definition of residual demand (i.e. higher residual demand means low wind output, and vice versa).

Figure 6: South Australian wind output and operational demand, first quarter



Source: Authors' calculations based on data from AEMO

The third characteristic of wind farms is the high correlation between one wind farm's output and that of other wind farms located in a similar geographic area. Again focusing on South Australia, Figure 7 shows the correlation matrix of the output of ten South Australian wind farms, during the 2018 calendar year. The figure shows that all 10 wind farms have a positive correlation with one another, with correlations ranging from 0.35 to 0.95.

The high positive correlation of output between wind farms, and the negative correlation between wind farm output and demand, together means that there is more aggregate supply available at times when wind farms generate, and so spot prices tend to be lower at these times. This phenomenon is termed the 'wind correlation penalty', as noted by Hirth (2013) and MacGill (2010). This penalty has increased as wind farm penetration in South Australia has increased.

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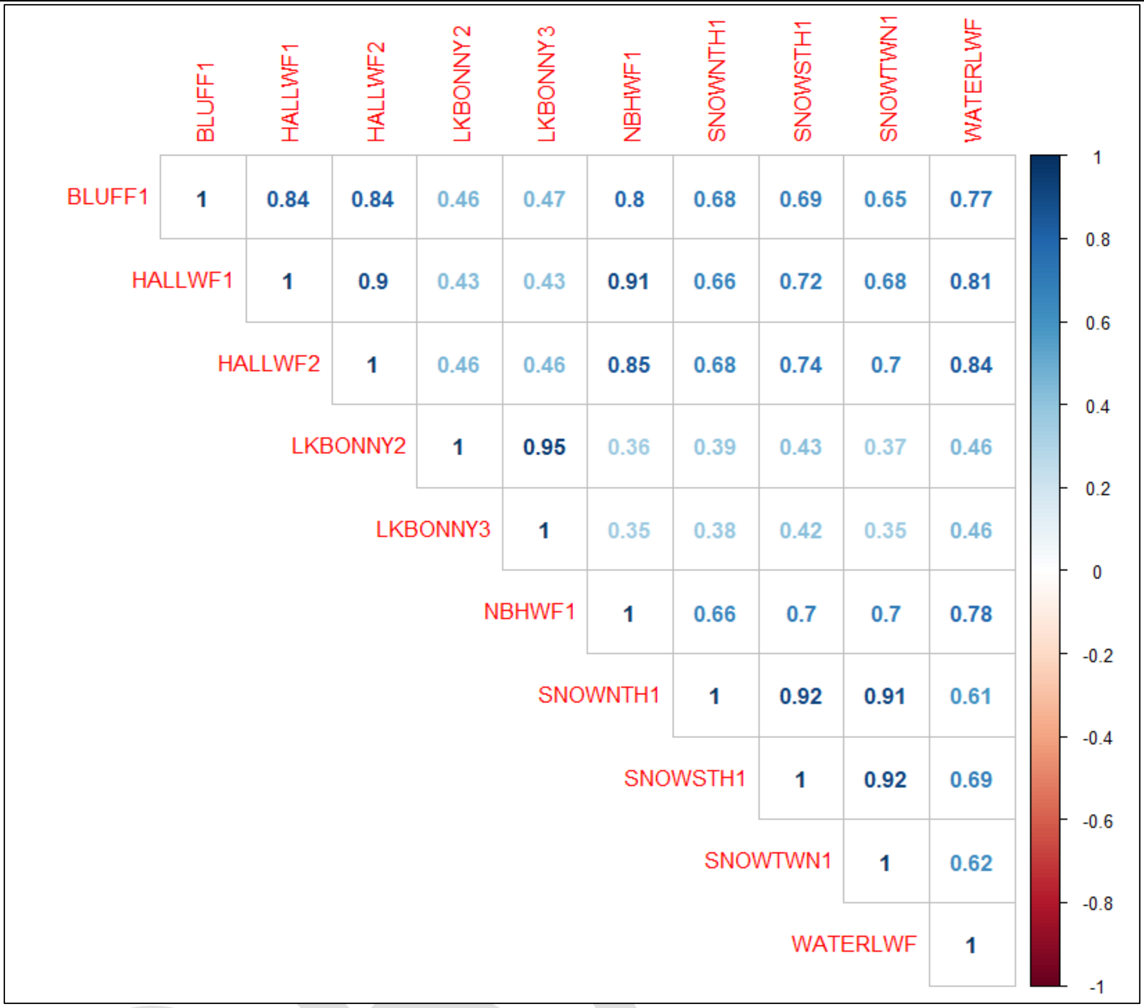
Figure 7: Correlation matrix of output of selected wind farms in South Australia



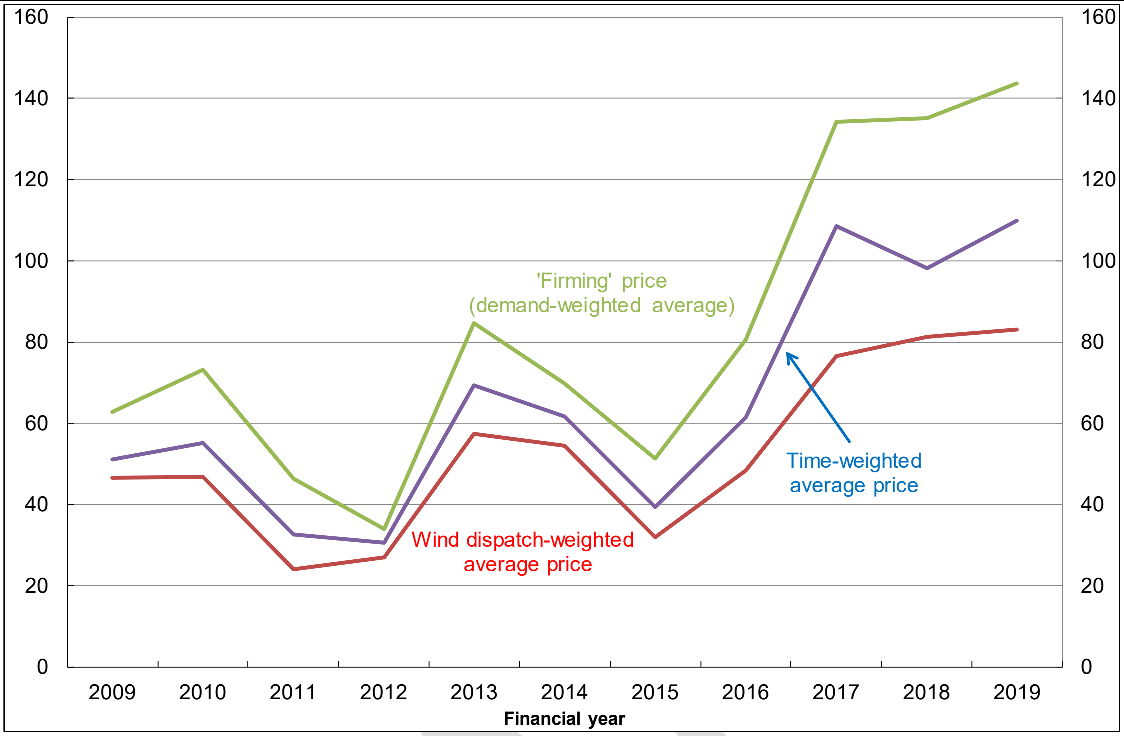
Source: Authors' calculations based on data from AEMO

2.3 The dispatchability premium

The three above-mentioned characteristics mean that wind farms can, and do, receive dispatch-weighted prices that are lower than either time-weighted average prices or firming prices. The firming price premium is higher than the premium based on time-weighted average prices, due to the increased volatility in residual electricity demand. This price premium therefore reflects the value to a plant that is both dispatchable and flexible. For example, during the 2019 financial year, the firming price was around \$144/MWh, compared to a time-weighted average price of \$110/MWh, and wind farm average DWP of \$83/MWh (Figure 8).

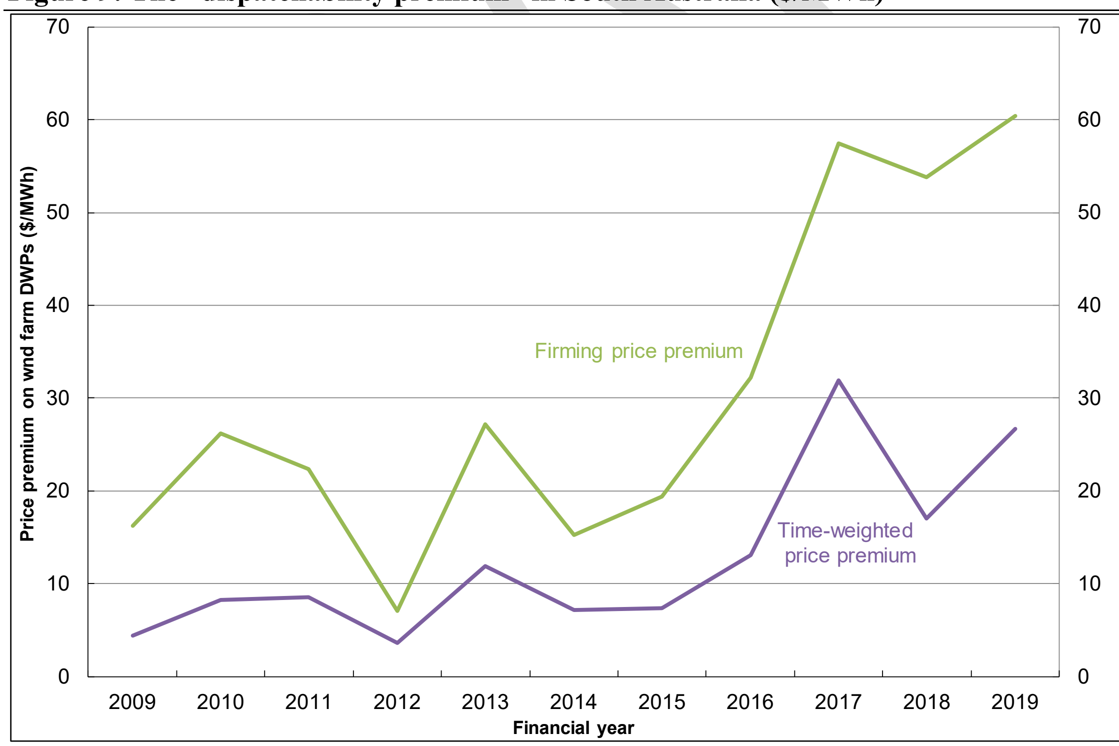
In addition, the firming price premium has increased over time. For example, the premium was around \$61/MWh (i.e. \$144/MWh *less* \$83/MWh) during the 2019 financial year, compared to a premium of \$15/MWh during the 2014 financial year. In \$/MWh terms, this increase has been greater than the increase in the time-weighted average price premium, which has risen from around \$7/MWh to \$27/MWh over the same period (Figure 9). The increasing volatility of residual demand (shown in Figure 4 and Figure 5) has pushed up the firming price vis-à-vis the time-weighted price.

Figure 8: Three dispatch-weighted spot prices in South Australia ($/MWh)



Source: Authors' analysis of AEMO data

Figure 9: The "dispatchability premium" in South Australia ($/MWh)



Source: Authors' analysis of AEMO data

When expressed as a mark-up on wind farm average DWPs, the firming premium averaged 73 per cent over the 2019 financial year, while the time-weighted premium averaged 32 per cent.

Both of these premia have more than doubled since 2014, with the second price premium increasing by more (from 28 per cent to 73 per cent) than the first (from 13 to 32 per cent).

The dispatchability premium is likely to provide signals for entry of dispatchable plant, at least in the absence of the entry barriers noted in section 1. Despite consistently high electricity prices across the NEM since 2016, only 210MW of dispatchable plant (one gas-fired unit) has entered: AGL's Barker Inlet in South Australia (Figure 1). In the absence of these entry barriers, and given the changing profile of residual demand, it is likely greater volumes of flexible and dispatchable plant would have entered, considering wholesale prices during the 2016-2019 financial years were well above wholesale prices during the late 2000s – and yet over 6000MW entered the NEM during that time, 30 times greater than what has entered the NEM since 2016.

Various studies (e.g. Simshauser, 2019; Nelson *et al*., 2015) noted the entry of VRE generators into South Australia was driven by the large-scale Renewable Energy Target (LRET[15]), a renewable portfolio standard which provides a "green" revenue stream in the form of large-scale renewable generation certificates (LGCs) bought by energy retailers.[16] The LRET created signals for VRE plant entry even when DWPs were low. For example, between the 2009 and 2015 financial years, wind farm average annual DWPs ranged from $25/MWh to $55/MWh (Figure 8). These prices were well below the long-run marginal costs for new-entrant wind, which at that time were in the $90-120/MWh range (IEA, 2017). Yet, over this period, South Australian VRE penetration (solely made up of wind) tripled from 10 to 30 per cent (Figure 2). In the absence of the LRET, the vast bulk of these wind generators would likely not have entered South Australia (or the broader NEM), as their DWPs would have been insufficient to fully recoup their costs.

3. Concluding remarks

There exists a significant and growing dispatchability premium in the NEM. We have defined this premium as the difference between the prices received by non-dispatchable plant (chiefly, VRE plant) and the prices received by dispatchable plant that are either inflexible or flexible. Using South Australia as an example, we calculated the dispatchability premium has averaged around 70 per cent since 2016, with this premium more than doubling between 2014 and 2019.

In the absence of LGC revenues (were the LRET to not be extended as currently seems to be the case) or other "green" revenues, prospective VRE investors would trade-off remaining variable vs. firming up their output; that is:

- comparing the DWP associated with remaining non-dispatchable, against
- the benefit of becoming dispatchable and thereby being able to earn a higher DWP, this DWP being closer to the time-weighted price, or perhaps even the higher firming price.

These investors need to evaluate the benefit of becoming dispatchable (and flexible, in the case of firming prices) against the associated costs. While no wind farms in South Australia (or, more broadly, VRE plant across the NEM) have added storage of a duration sufficient to earn either time-weighted or firming prices to date, this presents an opportunity for prospective VRE investors in the NEM and, going forward, an exciting potential market development on which to keep a watching brief.[17] The introduction of five-minute settlement in the NEM, from July 2021, is also expected to provide additional value to plant being dispatchable and flexible.

[15] The renewable energy target was set at 9.5 terawatt hours (TWh) by 2010. In January 2011, a target of 41 TWh by 2020 was set, but in June 2015 was subsequently revised down to 33 TWh by 2020. This annual amount remains unchanged through to 2030, which is when the LRET is scheduled to end (Rai *et al.*, 2019).

[16] Acquiring LGCs from VRE plant has been the cheapest way for retailers to acquit their LRET obligations.

[17] Some VRE plant have added limited-duration batteries (duration no more than 1-2 hours) to help with frequency and voltage control, and thereby avoid incurring costs associated with managing deviations in frequency and voltage that would otherwise occur as a result of the presence of the new asynchronous VRE plant. These batteries consequently have constraints on the ability of the co-located VRE plant to earn either time-weighted or firming prices.

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