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The role of gas price in wholesale electricity price outcomes in the Australian National Electricity Market

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Over the past 11 years, there has been a near-perfect correlation between natural gas prices and electricity prices in Australia's National Electricity Market (NEM), regardless of the underlying supply-demand balance and despite gas plant only operating for a small percentage of the year. A key question is whether this trend will continue into the future under conditions of extreme commodity prices and the transition to a net-zero emissions grid. We examine the underlying drivers of this correlation through analysis of the marginal price setter in the NEM's dispatch engine, and develop a minimal model of the NEM with a "grid heat rate" concept that accurately captures historical price dynamics. We find the NEM's energy-only market creates incentives for all participants to shadow price the marginal unit where possible, to maximise short-run revenues. Gas pricing therefore affects the bids of all units, and will continue to play a key role for as long as gas generators remain as peaking generation. Extrapolating forward, it is possible that grid heat rates, and hence the role of gas in pricing, will decline but will not disappear. Finally, we test this model against the extreme fuel and electricity prices observed in 2022 and consider the role of coal outages in driving extreme prices.

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1 Introduction

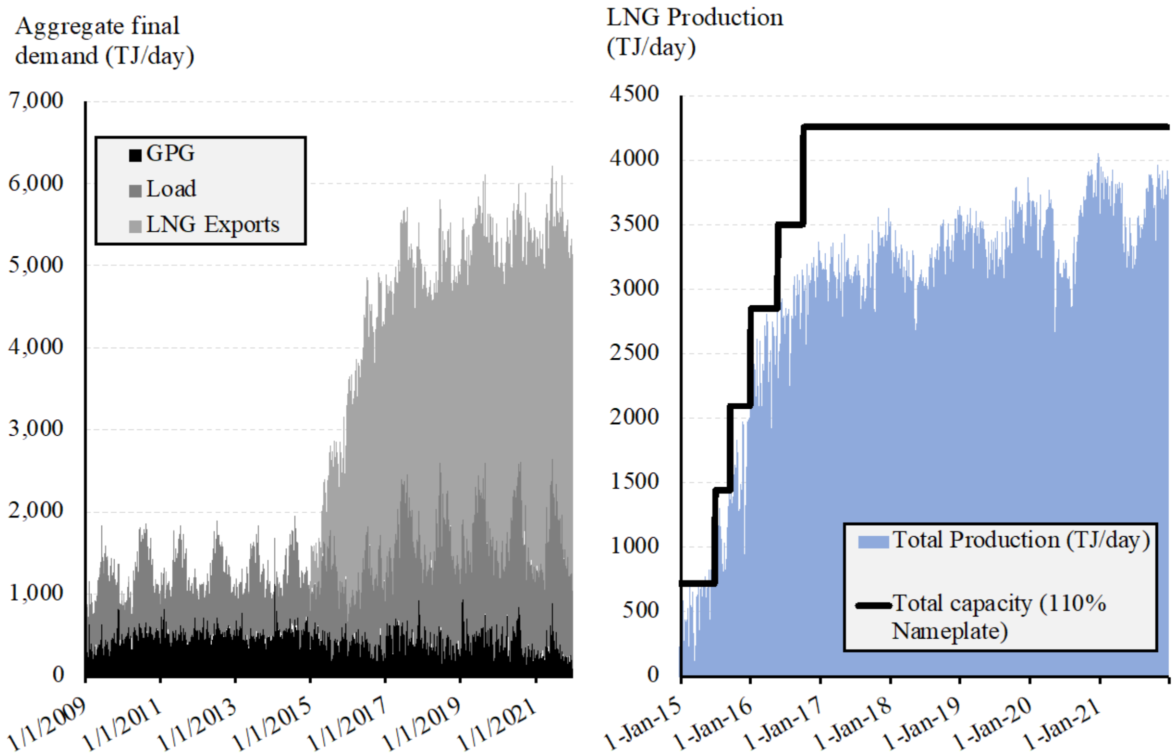
Australia's National Electricity Market (NEM) has been described as a 'marvel of micro-economic reform' (Simshauser & Nelson, 2014). Following the implementation of the energy only, gross pool, 5-minute market in 1999, a significant oversupply of generation was cleared, wholesale prices fell, and new investment was made by market participants.

However, over the past decade, the east coast Australian gas and electricity markets have been subject to a series of demand and supply side shocks. The NEM has recently undergone an investment megacycle, with the entrance of 25,000 MW of variable renewable energy (VRE) capacity in the period 2016-2021 and the disorderly exit of ~3,000 MW of coal fired generation. Average wholesale prices rose sharply from $30/MWh to over $100/MWh, before falling rapidly again as additional supply entered the market and COVID-19 caused demand to soften – only to rise to record levels as commodity prices rose following the Russian invasion of Ukraine. Combined with sharp rises in network tariffs, costs to end consumers roughly doubled over in real terms from 2009 to 2019 (Rai & Nelson, 2020; Simshauser & Nelson, 2014).

The NEM's evolution was not helped by the lack of a coherent national climate policy, an aging and increasingly unreliable coal fleet, and a range of state-based renewable energy targets. There is no immediate sign that the "energy trilemma" (reliable, affordable, clean) will be resolved any time soon, with market bodies floating major reforms to the NEM's energy only market (EOM) design and each state seeking its own path to achieve net-zero emissions by 2050 (Nelson, et al., 2021).

Furthermore, in 2015 Australia established an east coast Liquified Natural Gas (LNG) export market for the first time, tripling aggregate demand for domestic gas (and dwarfing consumption by gas-powered generation) and with further demand still possible, as shown in Figure 1. Initially, gas prices fell due to an excess of gas available from new fields ahead of the export market. Spare capacity to export at the LNG terminals linked domestic and international gas markets, and coincided with limited domestic gas supply and an increase in the production cost of domestic gas (Atholia & Walker, 2021). Subsequently, domestic gas prices fluctuated between $3/GJ and $10/GJ (and at times trading at over $50/GJ) over the cycle. Inevitably, higher fuel costs flowed through to the marginal running cost of domestic gas power generation (GPG) as existing gas contracts expired, new contracts were struck at materially higher prices (and some generators opted to take spot exposure). However, even contracted generators were known to sell gas back to the grid at spot prices rather than increasing electricity generation; effectively linking marginal running costs to the elevated spot gas prices.

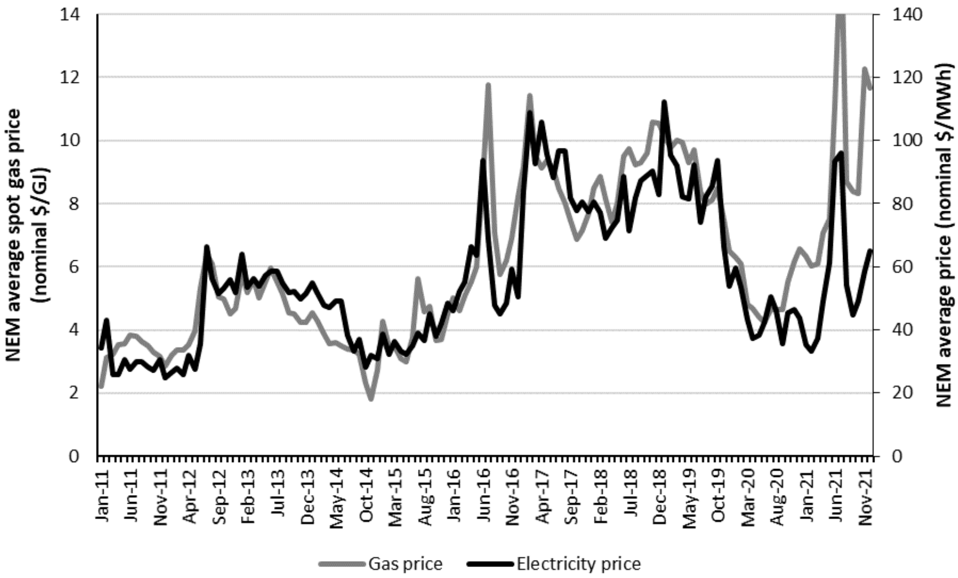
Figure 1 Domestic gas demand east coast Australia 2009 to 2021



Source: GMAT; adapted from (Simshauser, 2019)

Throughout these structural changes, a tight nexus has been maintained between the NEM wholesale spot price and the spot gas price, with few exceptions. Figure 2 shows a monthly average times-series of both NEM volume weighted under-cap electricity price and the average daily STTM ex-ante gas price. From July 2020 to December 2021, electricity prices appeared to diverge from gas prices, raising the question of whether the correlation was broken, reset, or otherwise.

Figure 2 Monthly averaged NEM-wide volume weighted under-cap electricity price and average daily gas price STTM ex-ante



To date, the literature has not quantified the underlying drivers or its robustness to significant supply side changes. In this article, we present a framework for quantify the underlying drivers of this correlation through the analysis of the marginal price setter in the NEM's dispatch engine for each 5-minute interval, and how fuel types other than GPG are responsive to the changes in gas price. We begin with analysis of the spot gas price and electricity price correlation over the period 2012 to 2021 on a monthly basis. Once extreme scarcity pricing is removed, we find a strong correlation of 0.90 between gas and electricity prices. We also find similar correlations existing in international markets.

We then develop a minimal model that captures the underlying dynamics with few parameters, which we derive from historical data. Average NEM characteristics over 2012-2020 is used to calibrate the model, and used to interpret the observed changes in 2021 and beyond. We use the model to quantify the direct and indirect impact of gas price on electricity prices including the role of non-gas powered technologies and show that the recent divergence is a shift to a new equilibrium relationship driven by higher penetrations of VRE. Finally, we extrapolate forward showing the application of this model to contribute insights on the current market conditions and the role of gas in electricity pricing.

These finding are important. Despite a declining role for gas peaking generation, we project gas prices will continue to drive wholesale spot prices by providing a benchmark price, particularly for storage technologies that do not have an easily definable marginal running cost. The gas price will therefore continue to impact both consumer and producer surpluses – leaving consumers exposed to sudden increases in gas price as has been seen in the UK and for short periods in the NEM market.

Our proposed minimal pricing model provides a transparent approach to quantifying the sensitivity of near-term electricity prices to gas prices, even as thermal coal and gas plant exit and new renewable and storage capacity enters. We propose that this approach can be used to calibrate more sophisticated strategic bidding or game theoretical pricing models, and will help utilities and governments better quantify fuel price risks to consumers.

This article is structured as follows: Section 2 reviews the relevant literature and provides examples in international markets. Section 3 introduces the drivers of the correlation and the role of price setting in the NEM. In Section 4, we introduce the minimal model and the inputs. Results and discussion follow in Sections 5 and 6.

2 Literature review

The NEM's energy-only wholesale market design features a uniform clearing price auction in which prices and volume are determined through competitive bids and offers[1]. Investment in new capacity driven through scarcity pricing at the high market price cap (AUD$15,100/MWh). The central question for energy only markets is the recovery of fixed costs and of missing money, a concept formally introduced in (Cramton & Stoft, 2005). This is particularly critical for peaking units that may only operate during infrequent periods of tight demand supply balance (Yarrow & Decker, 2014; Doorman, 2000; Milstein & Tishler, 2019). In the NEM, fixed costs are recovered through both scarcity pricing as well as inframarginal rents[2] including through transitive market power (i.e., offering capacity above marginal costs but still below competitors' offers). This feature of an energy-only market is important because it affects spot market bidding strategies and how marginal running costs of one fuel type influence the bidding strategies of another.

The relationship between the electricity price and natural gas price has been studied in both the academic literature and in technical reviews. It is generally accepted that electricity markets are highly correlated with natural gas markets. For example, Wood and Blowers (2018) observed that wholesale prices over 2015-2018 largely tracked the marginal running cost of GPG. They noted that the higher prices were largely as a result of higher mid-merit prices, rather than extreme peaks, consistent with higher input costs as well as "shadow pricing" by other generators in the NEM's energy-only market (discussed further below).

(Gonçalves & Menezes, 2022) used regression analysis to identify a positive impact of natural gas on wholesale electricity prices, with a diurnal coefficient that roughly tracked the demand shape (i.e., higher contribution during peak hours). The average coefficient was $5.6/MWh per $1/GJ increase, however the article does not discuss first principles drivers of the correlation. (Bushnell & Novan, 2021) undertook similar analysis of the Californian market and found an average coefficient of 5.98. They note that diurnal differences can be attributed to the heat rates of combined cycle versus open cycle generators.

(Lukes, 2021) notes that electricity wholesale price is highly correlated to natural gas because of the unique role of natural gas in the US market. Natural gas is the predominant marginal capacity in this market partly because of its higher costs that nuclear, hydro and coal, but primarily because of its flexibility. Prices in the wholesale market are set by the last dispatched unit and natural gas has a dominant role of setting price having an outsized effect on the overall electricity price. Lukes analysed over 33 publicly traded pricing points over 15 years across the United States and found the correlation held true. These correlations range between 0.81 in the Texas region to 0.96 in the Northeast and are stable over time.

In analysis of Ohio markets, (Thomas, et al., 2014) observed a correlation between PJM prices and Henry Hub natural gas prices, and expected the trend to continue as natural gas replaced retiring coal plants, noting the advent of shale gas development in the United States keeping

[1] Formally, generators make offers and loads make bids in the NEM. However, submitted prices are often collectively referred to as "bids", a convention which we have generally adopted in this article.
[2] That is, periods where generators are earning more for their generation than the marginal cost of production.

natural gas prices low increasing the likelihood of natural gas to be the fuel of choice for both new and peak generation.

The most comprehensive analysis of the gas price correlation in Australia to date was undertaken in (McConnell & Sandiford, 2019). They noted that high electricity prices were driven by a 'perfect storm' of high gas prices and a lack of competition in the market. Interestingly, when measured against prices at the Wallumbilla gas supply hub[3], they found no material correlation between electricity and gas prices prior to LNG exports commencing in 2015. In contrast, in this work we find the correlation persists back to at least 2012 (Figure 2) if the gas Short-Term Trading Market (STTM) prices are used instead, and so we adopt this metric.

McConnell & Sandiford also considered market power and the role competition plays in limiting opportunities for shadow pricing in the NEM. They found that after the closure of Northern Power Station in 2016 and Hazelwood in 2017 there was a large divergence between costs and prices, suggestive of exercise of market power. They surmise, the absence of competitive pressure allows coal generators to adopt a bidding strategy of shadow pricing gas prices.

A report by Houston Kemp (Forrest, et al., 2018) analysed gas generator bidding behaviours and spot pricing outcomes, focusing on the price pass through opportunities of gas powered generators. They developed an econometric model, and estimated gas generator bids could increase wholesale prices by $0.3-3.60/MWh per $1/GJ increase in gas prices (or up to $11/MWh in South Australia). Indirect price setting was not directly considered.

With the establishment of LNG exports on the east coast of Australia and linking domestic gas prices to international prices, some studies have noted how the effect on investment in gas power generation has linked gas prices to electricity price outcomes in the NEM (Simshauser, 2018; Grafton, et al., 2018). The higher prices not only caused the withdrawal of CCGT from the NEM but also increased the cost of entry of new gas fired generators (Simshauser, 2018).

While the observed electricity price gas price correlation has been noted by various commentators, no studies have attempted to quantify the underlying drivers of the correlation in the NEM or explain why it has remained so robust despite changes to the underlying supply. The NEM is seemingly very different to markets in the United States, where gas plays a much larger role in the generation mix than it does in the NEM. Another critical question of whether the correlation will persist into the future has also not been addressed in full, particularly as we transition to a net zero carbon economy and rely on gas powered generation less and less in Australia.

Therefore, this article develops a minimal model framework which can describe and capture these behaviours.

3 Relationship between gas and electricity prices

The sensitivity of the electricity price to the gas price depends on i) how often interval prices are driven by gas price and ii) the sensitivity of the price to gas prices in those periods. For example, if the wholesale electricity price was always set by GPG, wholesale prices should increase at approximately the heat rate of the marginal gas units. Conversely, if all bids were independent of gas pricing, then the correlation would be zero. In fact, from 2012-2020, average monthly wholesale prices in the NEM increase by $8.22/MWh per $1/GJ fuel cost increase (Figure 3). We refer to this relationship as the effective Grid Heat Rate (GHR) of the

[3] The Wallumbilla Gas Supply Hub was implemented in March 2014 and as an exchange for the wholesale trading of gas. It was introduced to improve the wholesale trading of gas for the east coast of Australia affected by significant LNG export.

NEM. Given the apparent separation of gas and electricity prices in 2021 (Figure 2), we separately calculated the GHR for 2021 which was indeed lower (shown in Figure 4 - 5.5 vs 8.2 historical average, noting the fit is through a small number of data points). Explaining these variations requires consideration of the underlying price setters and generator bidding behaviours and their contributions to the average price.

Figure 3 Monthly averaged NEM-wide volume weighted under-cap electricity prices vs average daily gas price STTM ex-ante 2012-2020

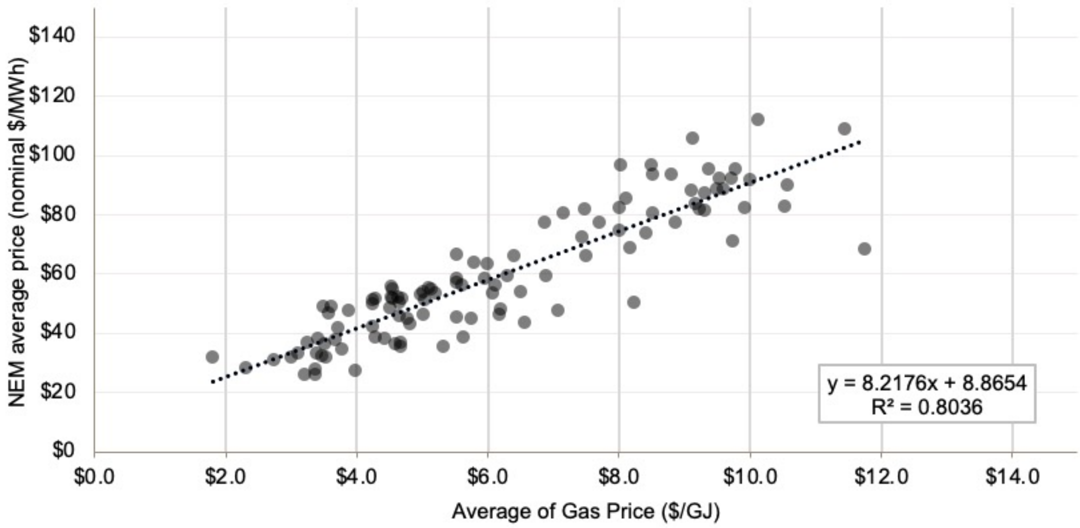
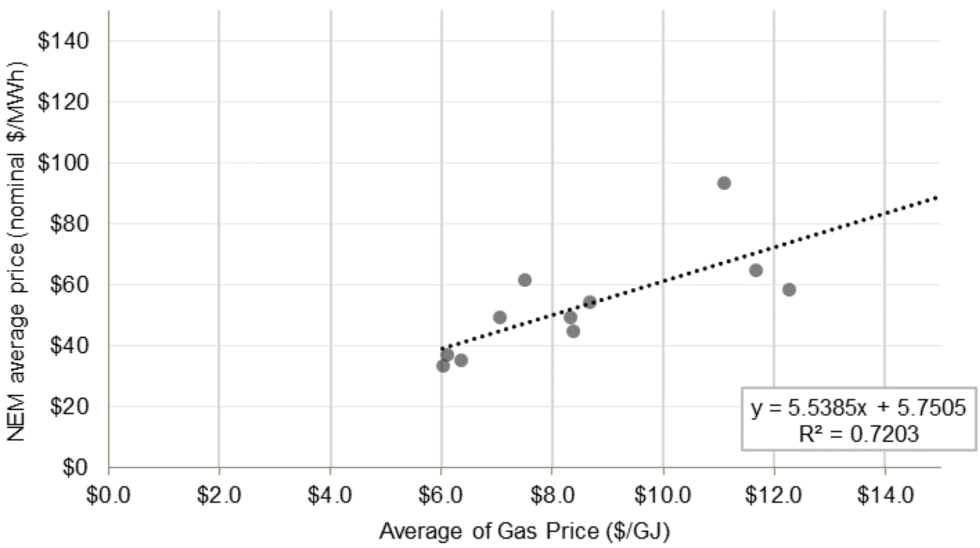


Figure 4 Monthly averaged NEM-wide volume weighted under-cap electricity prices vs average daily gas price STTM ex-ante for 2021



3.1 International examples

The link between gas and electricity prices is not unique to the Australian NEM. International markets see a similar correlation, such as New Zealand (correlation 0.67), ERCOT (correlation

0.83), and California (correlation 0.84)[4]. Figure 5, Figure 6, and Figure 7 show the time series of averaged spot gas price and averaged spot electricity price in each market respectively.

Figure 5 Quarterly averaged New Zealand electricity price and average gas spot price

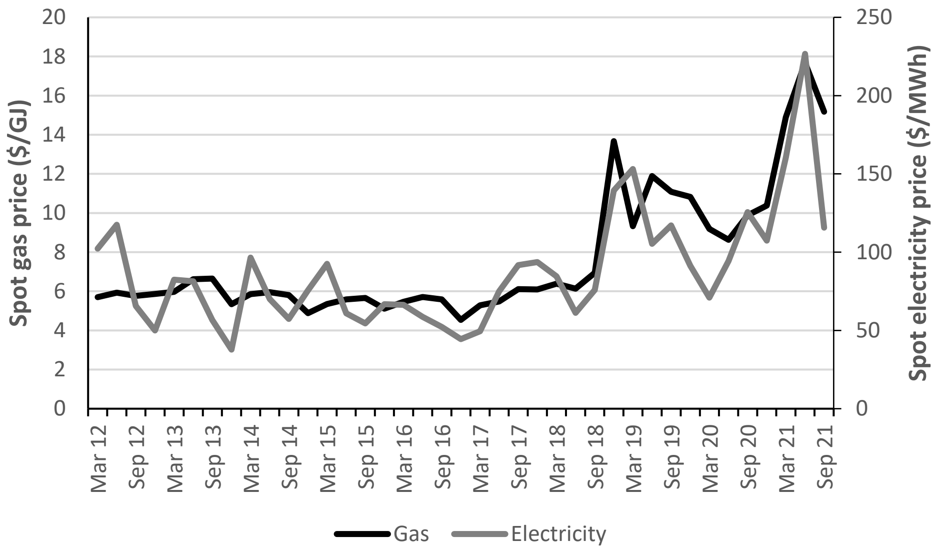
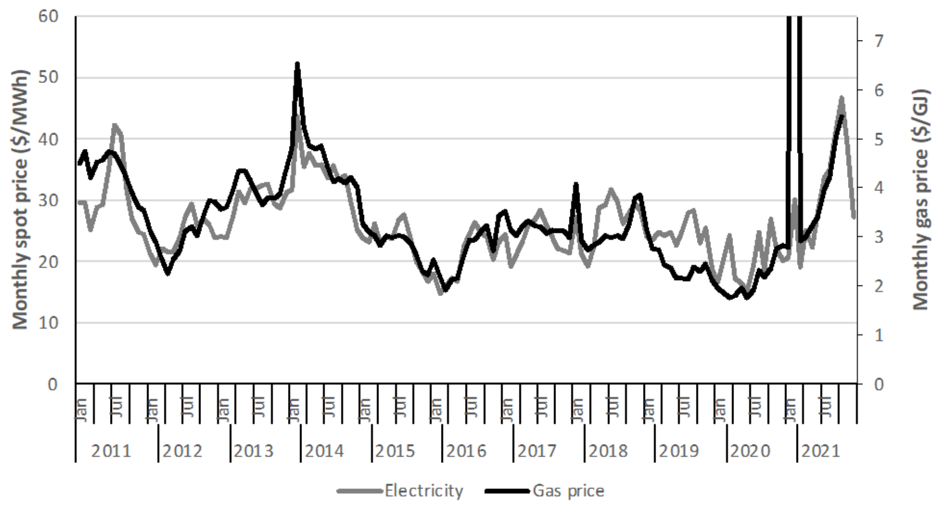
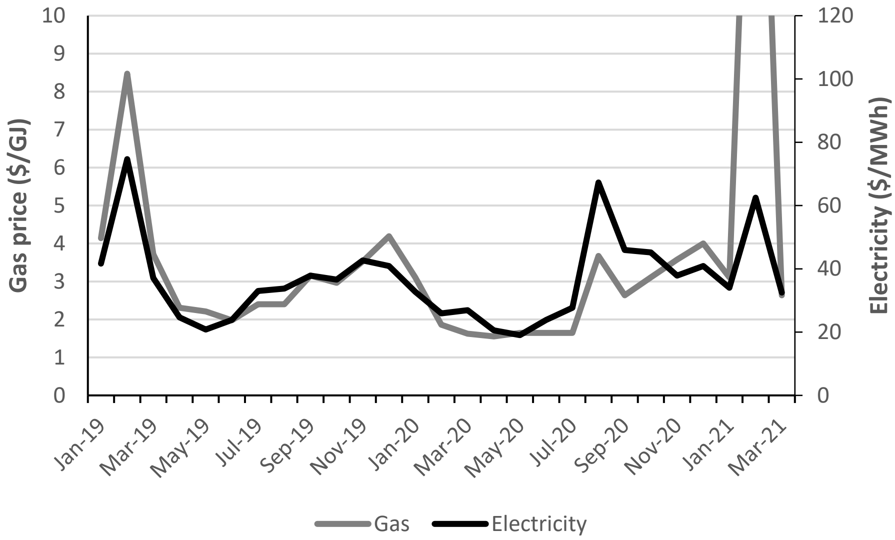


Figure 6 Monthly averaged ERCOT electricity price and average monthly gas spot price



[4] US correlations exclude February 2021, due to the extreme weather conditions, outages, and fuel shortages.

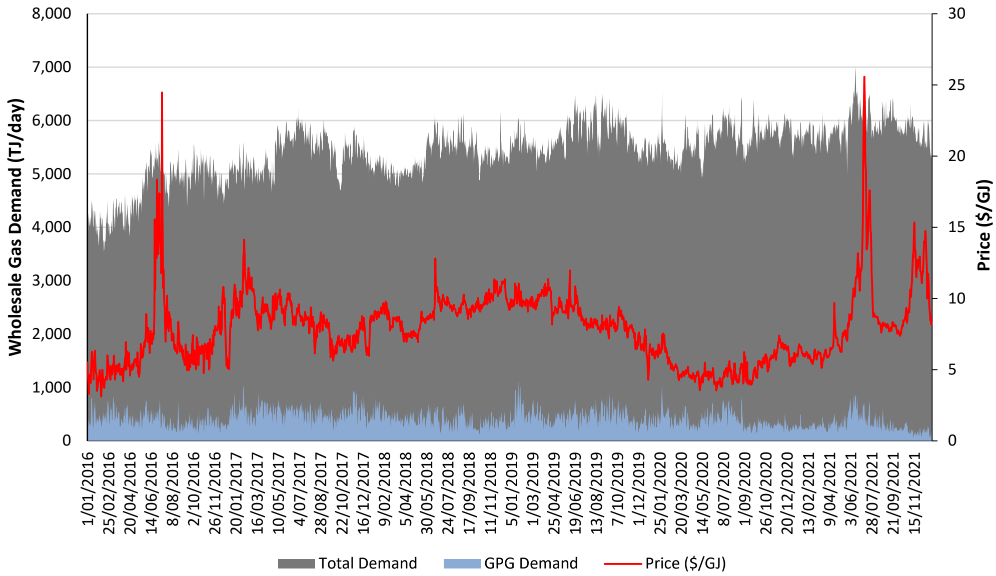
Figure 7 Monthly averaged California ISO electricity price and gas spot prices



3.2 Does electricity demand drive gas price?

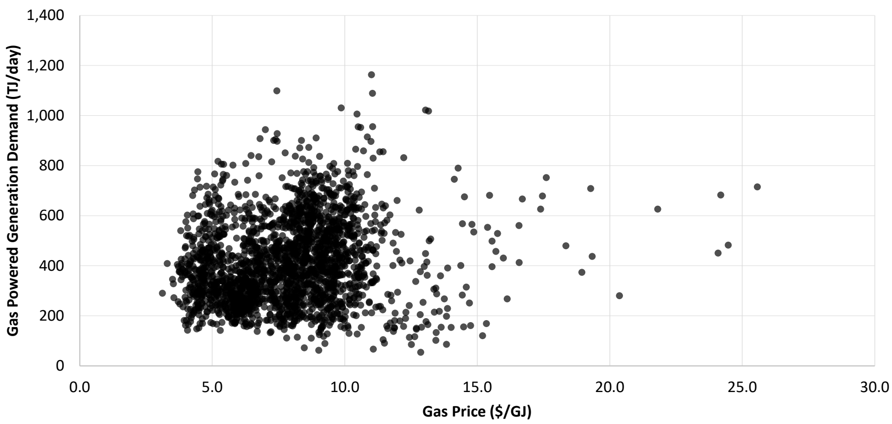
As is often pointed out, correlation does not imply causation. While we have implicitly assumed above that it is higher gas prices driving higher electricity prices, it could be plausible that higher electricity prices create increased demand for gas (and hence higher spot prices) or that there is a third factor influencing both (e.g., cold days lead to higher electricity and gas heating loads). In practice, we find little evidence to suggest GPG gas usage materially influences the price of gas in Australia under normal conditions. As seen in Figure 8, GPG demand is typically only 8% of total gas consumption. Gas price and GPG demand are mostly uncorrelated (correlation factor 0.165), as shown in Figure 9. This is consistent with (Uribe, et al., 2018) that found the feedback effect from electricity to gas was dimmed if the electricity generation mix was diverse enough or dominated by generation technologies that were not natural gas reliant. This is the case in the NEM with GPG only contributing 7-12% to the overall energy mix over the last 10yrs. Uribe et al. found a stronger effect in markets such as New England, where 50% of the generation mix comprises GPG, and weaker in markets like Pennsylvania-New Jersey-Maryland where GPG only comprises 24% of the generation mix.

Figure 8 GPG gas demand and total gas demand per day in TJ/day for east coast of Australia with gas price $/GJ



Source: GMAT

Figure 9 Scatter plot of GPG gas demand (TJ/day) against gas price ($/GJ) showing no strong relationship



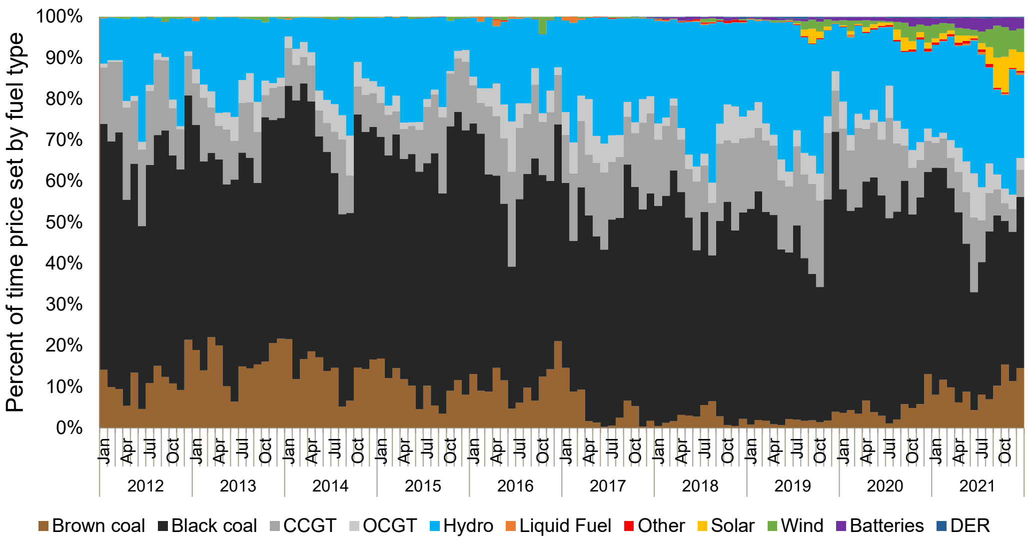
3.3 Price setting in the NEM

The NEM is an energy-only, gross-pool market, with all units re-dispatched every five minutes. A NEM unit is permitted to bid its generation in up to ten price and quantity “bid bands”, and capacity can be moved between price bands up to 54 seconds before dispatch (the time taken for the dispatch run). While the NEM’s market design broadly incentivises generators to bid at their marginal costs, units are in principle permitted to offer their capacity at any price subject to “bidding in good faith” rules that seek to limit the exercise of market power. As such, prices can rapidly swing between typical $30-100/MWh prices down to the market floor (-$1000/MWh) during periods of excess supply, and up the market price cap ($15,100/MWh) during scarcity periods.

Prices in the NEM are determined by the marginal cost of meeting the next megawatt of demand as determined by the NEM’s linear dispatch engine, NEMDE. The unit or units responsible for setting this price is driven by bids, constraints (by intra- and inter-regional), and the requirements of other co-optimised markets. We have analysed historical price setter data published by the system operator. The interconnection of the NEM means that prices in multiple NEM regions can often be set by the same unit or units. For example, since 2011 the NEM price in *all* mainland regions was set by the same unit in 49.5% of periods. Therefore, when looking at the price setters and how gas prices impact the marginal price setter, we have analysed the mainland NEM together. Some simplifying assumptions have been made in complex price setting periods (see Appendix B), which is not expected to materially change the results.

The price setting by fuel type in mainland NEM is shown in Figure 10. Coal continues to be the prominent price setter, representing 14 GW of capacity installed in a 54 GW market. The strong uptake of Variable Renewable Energy (VRE) capacity (15.42 GW of wind and solar) has meant VRE output now regularly exceeds regional demand *minus* must-run (minimum stable load) capacity of online thermal units. VRE set price in 7% of periods in 2021, and this is likely to grow over time. The range of price setting by Gas Powered Generation (GPG) in the NEM ranges from below 10% to above 30% of the month (average 19%).

Figure 10 Price setting by Fuel Type in Mainland NEM 2012-2021



3.4 Direct and indirect impacts

Higher fuel costs affect average electricity prices in two distinct ways. Firstly, gas price increases directly increases the marginal running cost of GPG and so increases wholesale prices in those periods where it contributes to the electricity mix. The heat rate of NEM CCGT is typically around 7 GJ/MWh (60% thermal efficiency) and an OCGT is typically around 13 GJ/MWh (35% thermal efficiency) with the capacity weighted average[5] of all units across the NEM being 10.64GJ/MWh (AEMO, 2021). It is therefore clear that the contribution to the wholesale price of GPG units alone is not sufficient to reproduce the observed correlation (Wood & Blowers, 2018; Forrest, et al., 2018; McConnell & Sandiford, 2019). As per Section 4.3, GPG units have historically set price in 19% of periods meaning the *direct* impact of gas price increases on electricity prices should be 19% $\times$ 10.64 = \$2.02/MWh per \$1/GJ gas price increase. This is significantly less than the observed 2012-2020 average NEM GHR of 8.22 GJ/MWh.

The remainder of the GHR is due to the indirect impact of gas prices on the strategic bids of other generators. In an energy only market such as the NEM, market participants can adjust their bids to maximise revenues in any given interval if there is sufficient market power

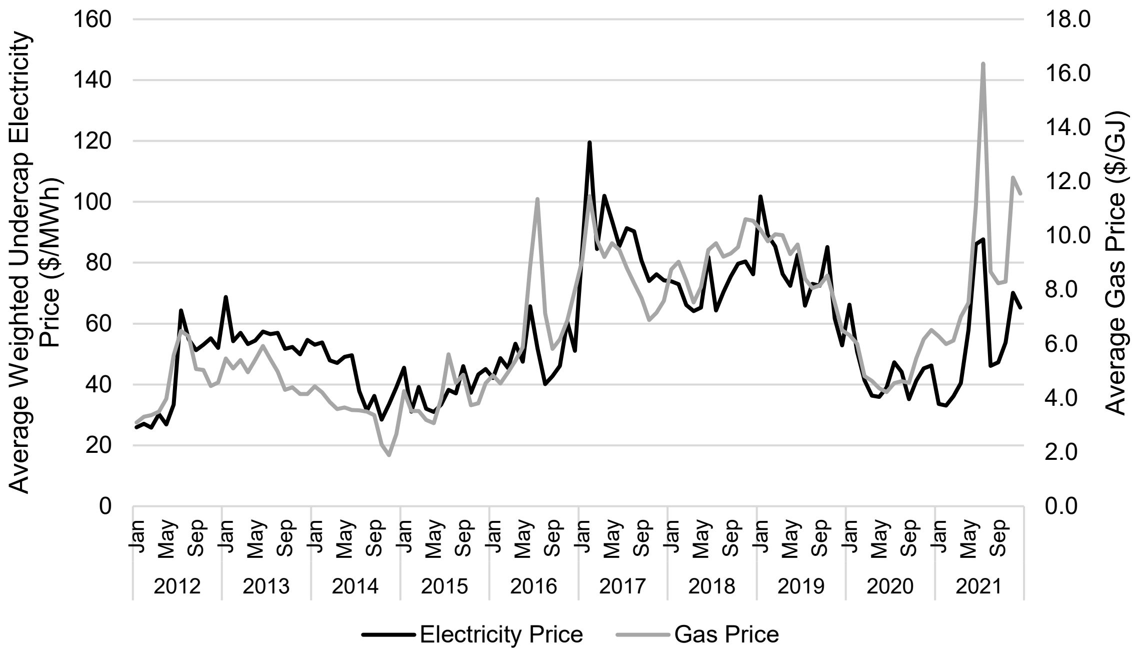
[5] In practice, not all units set the price equally. However, a more complex weighting does not materially change this analysis.

concentration (Yarrow & Decker, 2014). In particular, coal units regularly shadow price the marginal gas unit, as noted by Australia's competition regulator (ACCC, 2018):

> *"A bidding strategy document from that same [coal] generator noted that its intention was, after its contract position was covered, to 'bid our remaining coal generation at the staggered prices that ensure full dispatch at the highest possible price before gas generators start."*

This behaviour is reflected in the NEM price setter data. Figure 11 considers only periods where black coal units are setting the price and shows that the correlation between gas price and electricity price is broadly retained, with a correlation co-efficient of 0.86 between 2012 to 2020. The effective GHR for periods when black coal is price setting is $7.36/MWh per $1/GJ of gas price increase. This can only be explained if the bids of coal generators are linked to the natural gas price (i.e., shadow pricing[6]).

Figure 11 Average Time Weighted Electricity price ($/MWh) of all intervals per month across all region where price is being set by black coal-fired generators (2012-2021)



4 Minimal model of gas-electricity price relationship

A minimal model was developed to explore the behaviours and relationships of the gas price and the electricity wholesale price in the NEM. The model aimed to capture the link between each fuel type and the gas price to produce the effective GHR, explain NEM price outcomes each year. This approach has some similarities to the use of load blocks in long-term planning studies, where similar periods (e.g., "overnight low-wind hours") are grouped together. However, in contrast to typical expansion planning models, the model incorporates the possibility of strategic bidding behaviours by participants, where capacity is not offered at its underlying cost but rather shadow price another technology.

In the simplest formulation, the average price over a given period can be expressed as:

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[6] There exists a weak positive correlation between average monthly coal price and gas prices, but not sufficient to explain the relationship.

$$\langle P \rangle = \sum_{tech} \%P_{tech} \times \left((1 - \%S_{tech}) \times M_{tech} + \%S_{tech} \times HR_{gas} \times C_{gas} \right) \qquad (1)$$

Where $\langle P \rangle$ = the average price over the period, $\%P_{tech}$ = the percentage of time each technology is the price setter, M_{tech} = the marginal running cost of the technology, $\%S_{tech}$ = the percentage of price setting periods the technology is shadow pricing a gas unit, HR_{GPG} = the heat rate of the benchmark natural gas unit (GJ/MWh), and C_{gas} = delivered natural gas price.

For GPG, the marginal running cost is $M_{tech=GPG} = HR_{GPG} \times C_{gas}$. This equation allows for only a single form of strategic bidding – shadow pricing the marginal GPG – but could be extended to allow shadow pricing other fuels, for strategic bidding from storage based on a future opportunity cost, or for co-optimisation with other markets (if applicable).

The grid heat rate (GHR) can then be defined as the partial derivative of price with respect to the natural gas price C_{gas}. The general form for the GHR (with respect to gas price) is then:

$$GHR = \frac{\partial \langle P \rangle}{\partial C_{gas}} = HR_{GPG} \times \left(\%P_{GPG} + \sum_{tech \neq GPG} \%P_{tech} \times \%S_{tech} \right) \qquad (2)$$

It remains to estimate these parameters based on historical or forecast data, which we do in the following sections.

The minimal model treats generators of a particular fuel type as homogenous. Inputs for fuel cost, shadow pricing percentage, price setting percentage are all on a fuel type basis. In practice, the short-run marginal cost (SRMC) will vary between units; the cost of the typically marginal unit in a technology is relevant input for the purposes of the model.

4.1 Inputs for Black coal generators

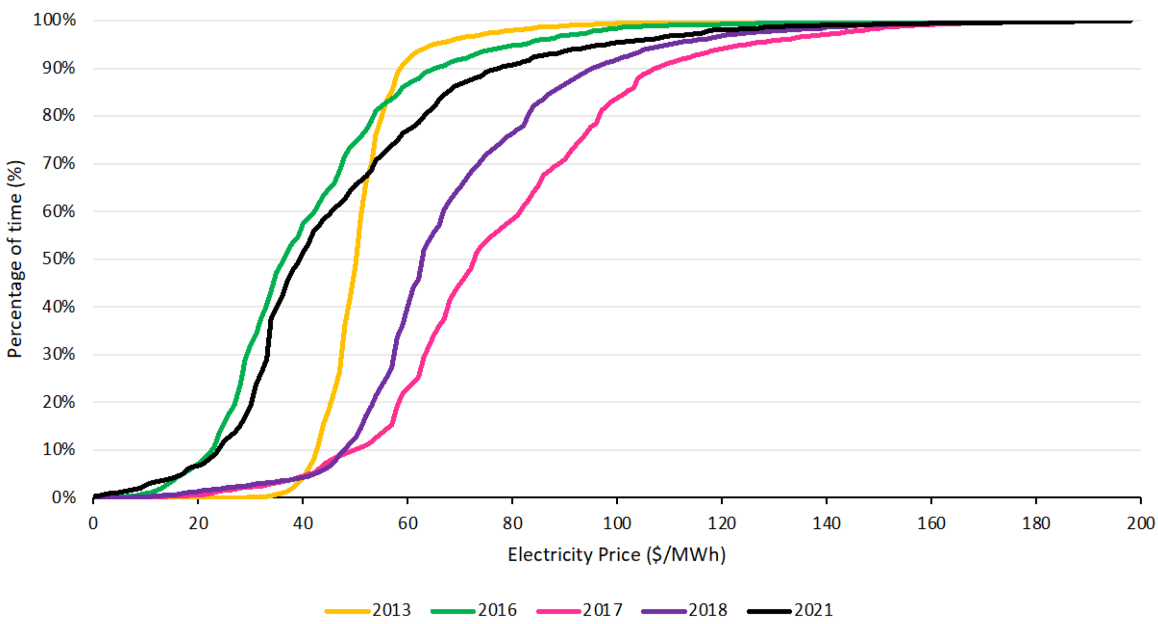
Coal supply contracts are typically proprietary information, but most generators have some spot exposure (directly or through an opportunity cost) that influences their marginal bids. We use the Newcastle coal index (coal export market) as a metric for black coal fuel cost; methodology for this approximation is presented in Appendix B. Table 1 shows the estimation of black coal fuel cost from 2012 to 2021. Notable periods include the introduction of the carbon price on 1 July 2012 and the subsequent repeal on 1 July 2014, and 2021 where coal export prices reached historical highs.

Table 1 Proxy for black coal fired generation marginal running cost in the NEM

Year	Marginal running cost ($/MWh)
2012	44
2013	53
2014	39
2015	28
2016	32
2017	42
2018	52
2019	40
2020	32
2021	69

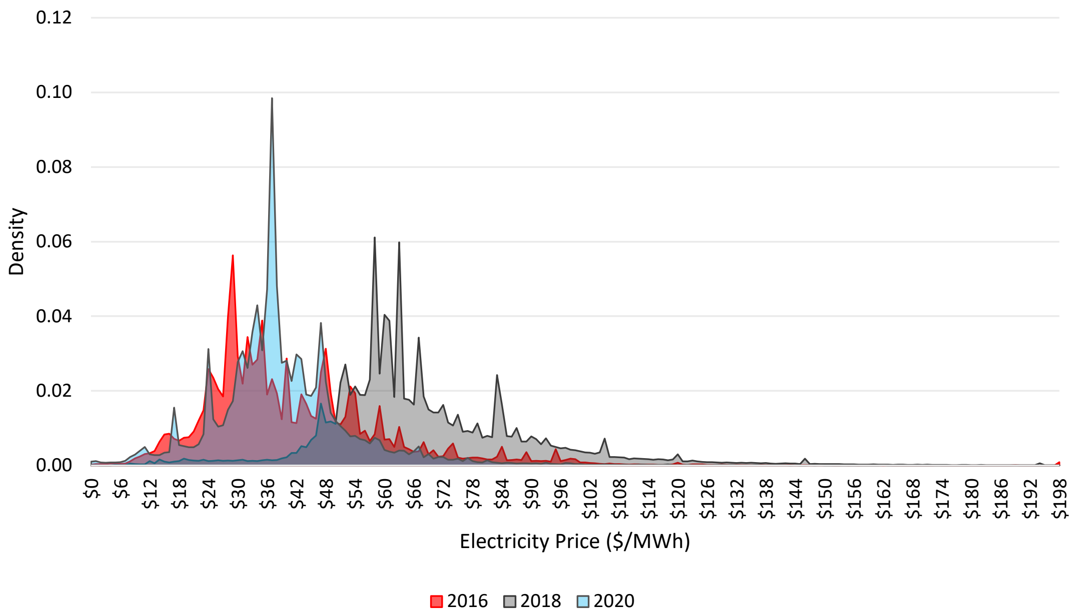
To estimate when coal units were shadow pricing gas, prices were compared to the estimated SRMC. Figure 12 provides a price duration histogram of prices set by black coal fired generators. In in 2021, 85% or more prices set by black coal are at or below the estimated SRMC for the year, consistent with the oversupplied market conditions. This contrasts with 2016 at 38%, 2017 at 5% and 2018 at 17%. In 2013, the higher SRMC of black coal generators due to the carbon price and the disproportional impact the carbon price had on CCGT plants resulted in black coal generators setting price at or below SRMC for more than 90% of price setting periods.

Figure 12 Cumulative histogram of prices set by black coal fired generators by year (2012-2021)



Presenting the Figure 12 data as a density histogram, Figure 13 shows that 2020 has the tightest distribution of prices, with a large proportion of price setting at $38/MWh – that is, less strategic bidding and consequently a lower average GHR for coal units in that year.

Figure 13 Density histogram of prices set by black coal fired generators by year (2016, 2018 and 2020)



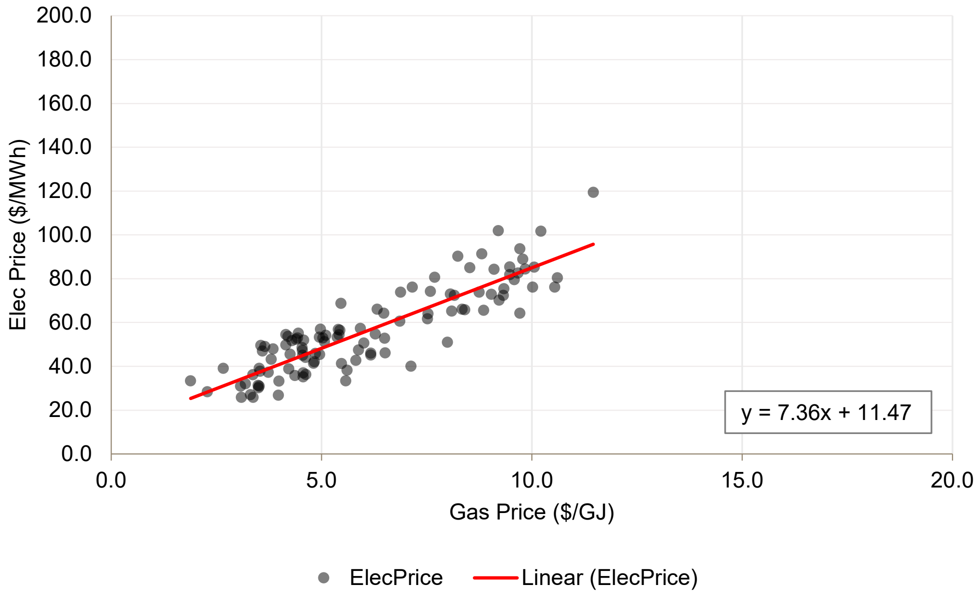
To develop estimates for the historical $\%S$ values, we have extracted black coal-fired generators setting price close to SRMC and black coal-fired generators setting price shadow pricing gas (this is estimated by gas price multiplied by a gas generator heat rate of 10.64GJ/MWh as described in Section 4.4).

Table 2 Price setting by black coal fired generators in the NEM, portioned by setting price at SRMC and shadow pricing

Cal Year	Total time price setting by Black coal ($\%P_{blk-coal}$)	Portion at SRMC	Portion shadow pricing	$\%S$
2012	55%	25%	31%	55%
2013	51%	0%	51%	100%
2014	57%	15%	41%	73%
2015	58%	23%	35%	60%
2016	51%	20%	30%	60%
2017	49%	3%	46%	95%
2018	50%	9%	40%	82%
2019	47%	6%	41%	87%
2020	52%	32%	19%	37%
2021	41%	35%	6%	16%
Average	51%	17%	34%	66%

Based on Table 2, during periods where black coal is setting the price, Eq.2 gives the effective GHR as $HR_{GPG} \times \%S_{black\ coal}$= 7.37 over 2012-2020. This matches closely with the observed monthly data in Figure 11 and in scatter plot Figure 14

Figure 14 Monthly average gas price (STTM, ex-ante) vs monthly average weighted price set by black coal in the NEM, 2012-2020

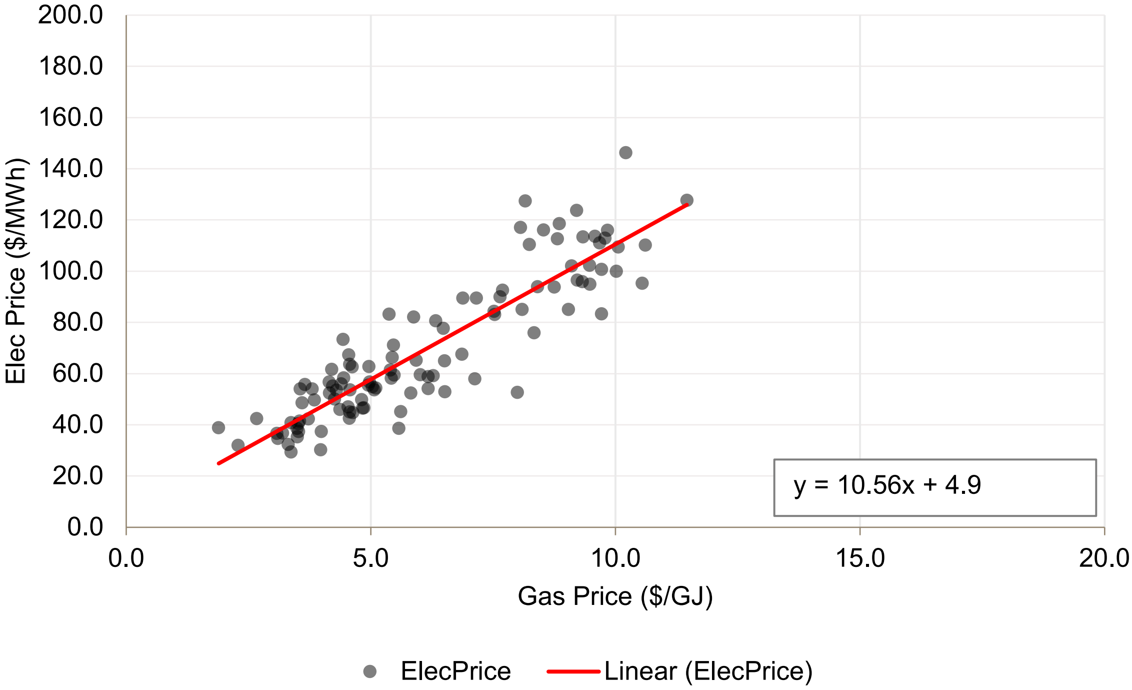


4.2 Inputs for Hydro generators

Hydro generators are typically energy constrained and so the cost of operating a hydro generator is based on the opportunity cost of the water stored in its dam, rather than a simple marginal running cost. As shown in Figure 15, a strong correlation ($10.56/MWh per $1/GJ) is observed. Despite the complexity of determining an opportunity cost, we find that price setting bids by hydro generators in the NEM closely align with the average GPG heat rate. It suggests that when a hydro unit is the price setter, it is almost always *on average* shadow pricing GPG[7], with a slope consistent with the volume weighted benchmark heat rate estimated above.

[7] In practice, as with all technologies, there is a range of marginal costa and hence bids in the market, particularly from peaking generators.

Figure 15 Monthly average gas price (STTM, ex-ante) vs monthly weighted average price set by Hydro in the NEM, 2012-2020



4.3 Other technologies

Brown coal generators are large inflexible units in the NEM, which operate at high-capacity factors. Brown coal rarely sets price (2-16% of periods) and its bids are only weakly sensitive to gas pricing, which may be an indirect setting through shadow pricing black coal (which is not included in the minimal model). Sensitivities on $\%S$ between 0 and 30% had a less than 1% impact on the resulting GHR for that period. For simplicity, we have subsequently modelled assume no shadow pricing behaviour from brown coal and a marginal running cost of $10/MWh. Similarly, we assume variable renewables and other technologies (e.g., biomass, landfill gas, etc.) do not shadow price gas generators.

4.4 Summary of model inputs

The historical price setting inputs are summarised in Table 3 for each calendar year.

Table 3 Contribution to price setting ($\%P$) in the NEM by fuel type

Cal Year	Black Coal	Brown Coal	Gas	Hydro	VRE	Other
2012	55%	11%	17%	16%	0%	0%
2013	51%	16%	15%	17%	0%	0%
2014	57%	14%	14%	15%	0%	0%
2015	58%	10%	14%	18%	0%	0%
2016	51%	11%	20%	17%	1%	0%
2017	49%	4%	22%	24%	0%	0%
2018	50%	3%	20%	27%	0%	1%
2019	47%	2%	22%	26%	2%	1%
2020	52%	5%	18%	21%	3%	2%
2021	41%	10%	14%	25%	7%	3%

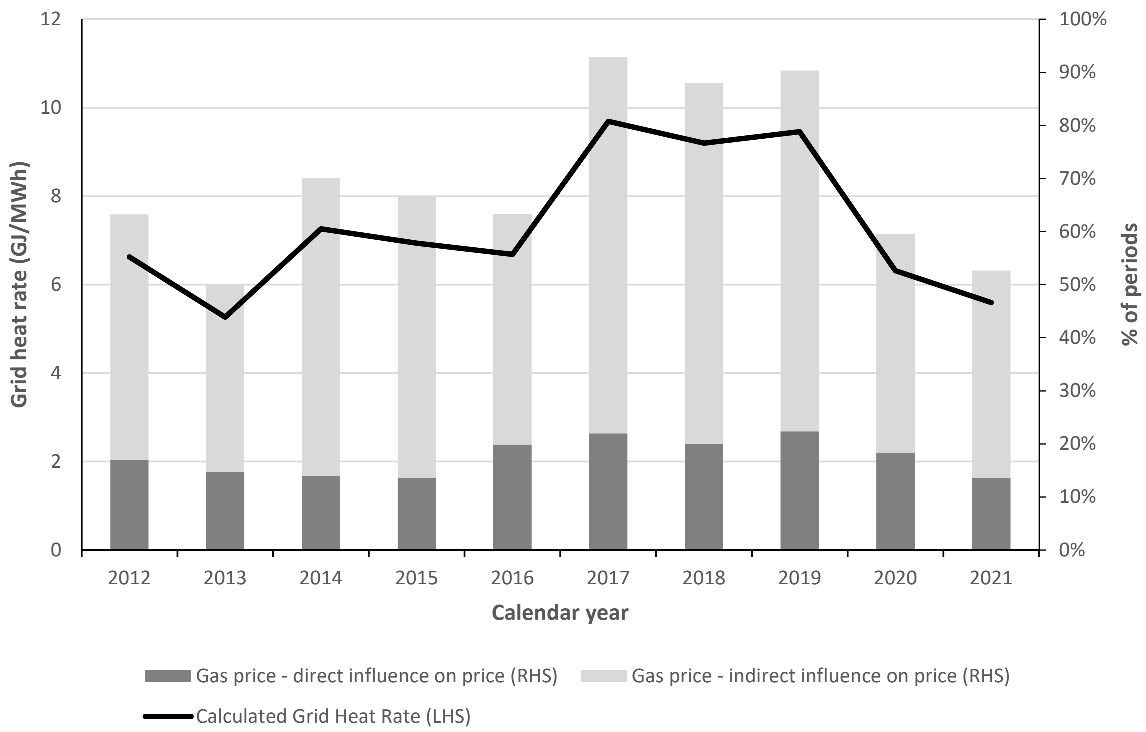
The SRMCs and $\%S$ for black coal are provided in Table 1 and Table 2 respectively. A nominal $10/MWh SRMC is assumed for brown coal, and zero for other technologies. Hydro is assumed to have $\%S = 100\%$, and zero for other technologies. The average benchmark gas heat rate is assumed to be 10.64GJ/MWh.

5 Results

5.1 Projected GHR

Figure 16 shows the resulting projections of the GHR using Eq. (2). The stacked bars show the percentage of time that gas sets price directly and indirectly, and the black line is the GHR. We find gas prices have set NEM electricity prices for between 50-90% of historical periods. Direct price setting makes up only a small percentage of the overall sensitivity. The average GHR from 2012 to 2020 is 7.3, which aligns closely with the average slope observed in Figure 3 (8.2 GJ/MWh), while the GHR for 2021 was 5.47 GJ/MWh, consistent with the observed slope of 5.54 GJ/MWh. We therefore find that the GHR was indeed lower in 2020-2021, but also not lower than history (2012-2016)[8]. The deviation in 2021 on Figure 2 is exaggerated because of the high underlying gas prices (over $9/GJ), which means changes to the GHR have a greater impact on wholesale prices.

Figure 16 Calculated grid heat rate using minimal model Eq 2. with the percentage of periods that are influenced by the gas price in the NEM

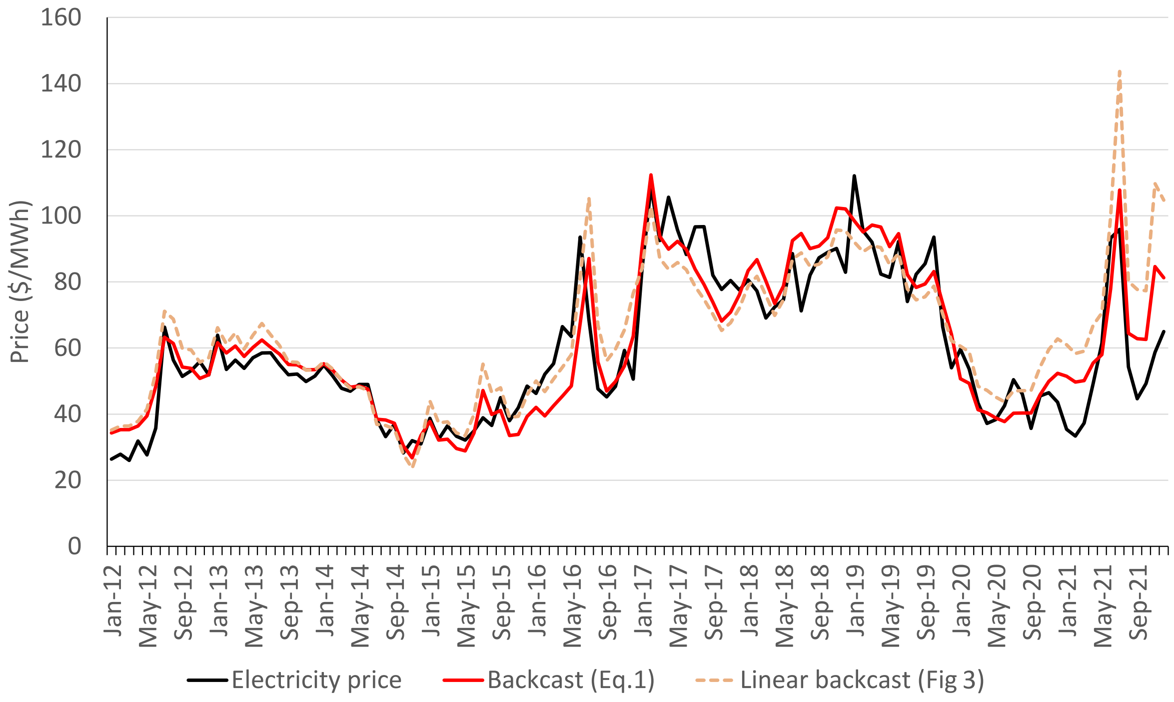


The minimal model in Eq.1 can also be used to produce price backcasts, shown in Figure 17, that give further insight into pricing dynamics. The black line shows the actual monthly (undercap) electricity prices, the red solid line uses Eq.1 with annual inputs which are outlined in Section 5, and the dotted orange line uses a simple linear backcast with the GHR = 8.2

[8] The minimal model projects an average GHR of 6.33 GJ/MWh over 2012-2016, while monthly average prices (extracted from Figure 8 just for this period) show a slope of 5.79 GJ/MWh.

based on the 2012-2020 average. Using annual inputs (red line) produces a higher quality fit, but even a simple backcast using the average GHR over the 2012-2020 period captures most trends – with some insightful exceptions, considered below. This analysis highlights that gas pricing has been a fundamental driver of NEM pricing, despite significant shifts in the underlying generation mix.

Figure 17 Backcast of monthly electricity prices using Eq. 1 and Linear backcast from Fig. 8 against actual monthly weighted average electricity price in the NEM ($/MWh)



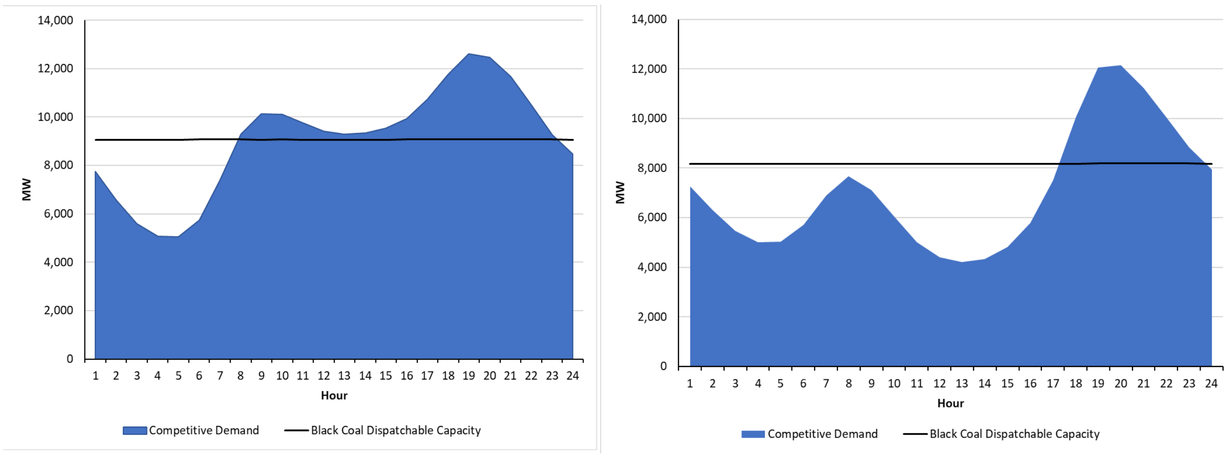
5.2 Case studies of specific events

The minimal model of Eq.1 provides a baseline relationship between underlying fuel costs and market prices, and therefore allows for the identification of abnormal electricity price outcomes and sensitivities to participant behaviours.

Explaining low electricity prices over 2020-2021

Over 2020-2021, record levels of both utility scale renewable energy generation and rooftop PV were installed (6.3 GW of rooftop systems were installed over 2020 and 2021 (CER, 2022)). Figure 18 shows the competitive demand in 2017 and 2021 (area chart), defined as the operational NEM demand minus production from renewables, brown coal generation and minimum (must run) coal generation i.e., the residual demand to be met by coal, gas, and energy storage. In 2021, competitive demand fell to record lows relative to available generation (above must run load) available from black coal (black line). Consequently i) gas was required must less frequently and ii) coal units were forced to compete amongst themselves rather than with gas, with resulting low GHR.

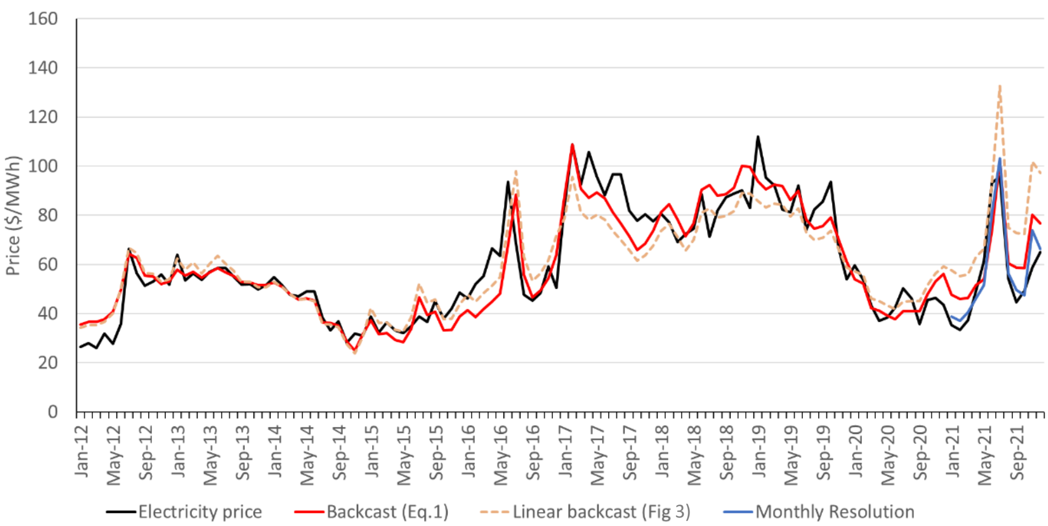
Figure 18 Average competitive demand by hour of the day 2017 (left) and 2021 (right) with average dispatchable black coal capacity



However, prices were still below the backcast projections of Eq.1, even accounting for the lower GHR. We attribute this to two structural changes over 2021. Firstly, there was diversity of actual coal SRMCs on a month-to-month basis, in some cases falling below the estimated export parity. Secondly, very low competitive demand in some periods may have meant the benchmark gas unit was more frequently a CCGT (rather than an OCGT), which was reflected in the sensitivity of prices in periods where hydro units set price in 2021 (7.5 GJ/MWh vs 10.56 GJ/MWh historically).

To consider these additional elements, Figure 19 shows the application of the minimal model using monthly resolution data (coal fuel costs and price setting percentages, but with annual $\%S$) and a reduction in the benchmark gas heat rate from 10.46GJ/MWh to 9 GJ/MWh. This shows that with higher resolution inputs, the minimal model is still applicable and can provide further insights into intra-year dynamics.

Figure 19 Backcast of monthly electricity prices including 2021 monthly resolution inputs backcast (blue line)

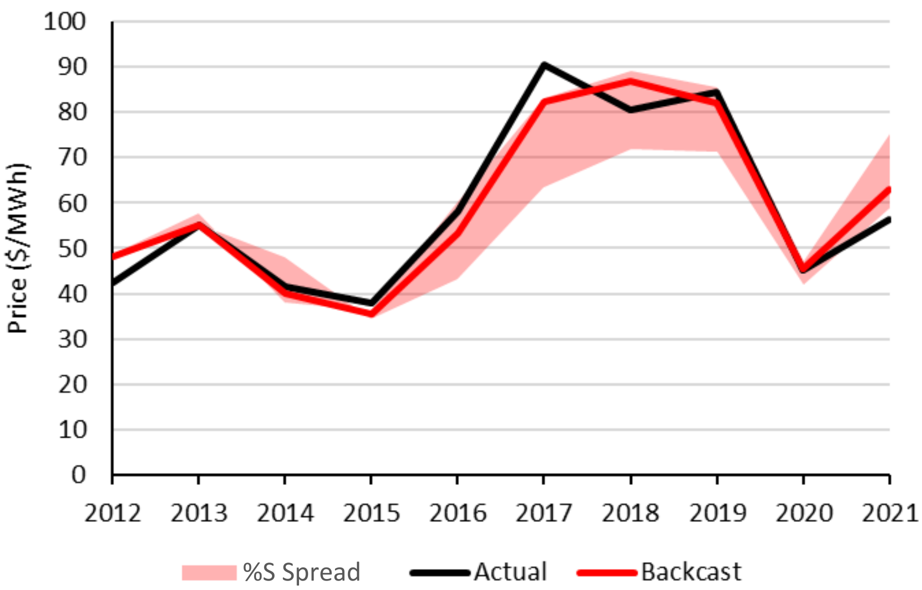


Impact of the closure of major coal unit

The minimal model is also useful for analysing system shocks, and identifying pricing impacts beyond typical trends. In September 2016, a 52 year old, 1600 MW brown coal Hazelwood power station announced it would close in March 2017 following the identification of safety issues that would not be economical to fix. Wholesale prices rose significantly over the period April 2017-March 2018 relative to the previous 12 months (from an average of $69/MWh to an average of $86/MWh) which was widely reported as being due to a resulting shortfall in capacity, the exercise of market power, or both.

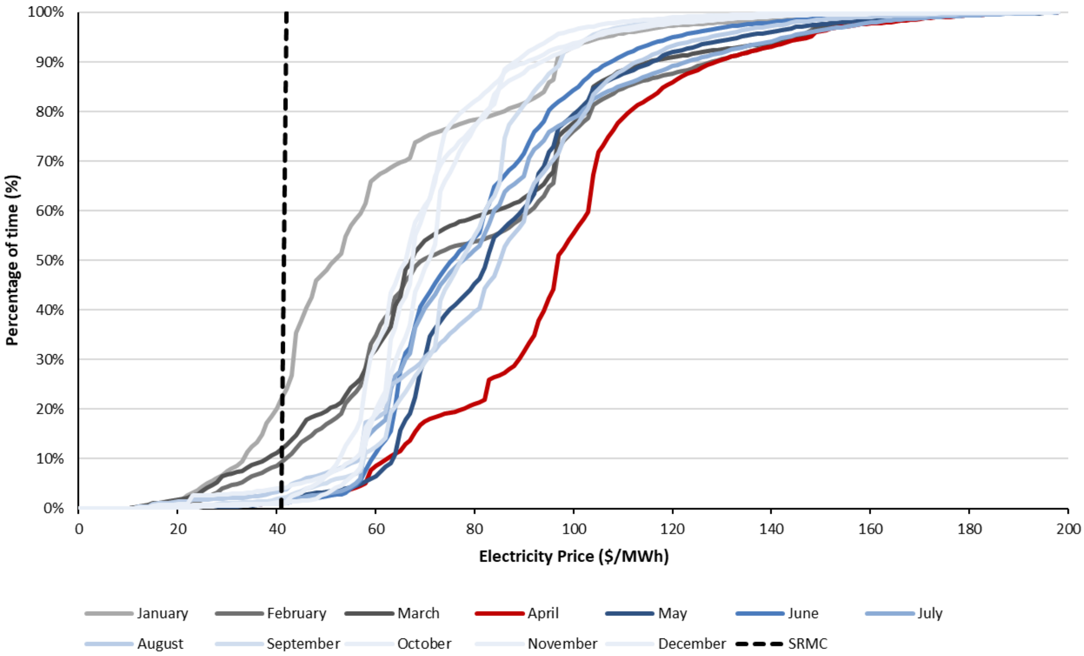
We note that gas prices also increased by ~$1.9/GJ in 2017, which would have led to an expected $13/MWh increase in wholesale prices based on the 2016 GHR of 7.00. However, strategic bidding behaviour by coal generators increased from 60% in 2016 to 95% in 2017 (Table 2), leading to a GHR of 9.39, contributing a further $4.50/MWh. More generally, Figure 20 shows the sensitivity of the price backcast to the level of strategic bidding of coal generators ($\%S_{coal}$ from 0-100%). The higher gas prices seen from 2016 to 2019 meant that prices would have likely risen in 2017, all else equal, but prices could have been $20/MWh lower if coal units had fewer opportunities to shadow price gas. A closure of a coal unit without investment in new renewable energy generation prior to its closure, could result in the competitive demand being above the dispatchable capacity of remaining black coal units. In the same way to the period after Hazelwood closure (Mountain & Percey, 2019), this provides remaining black coal units with the ability to exercise market power and have greater opportunities to shadow price gas. Appendix A considers the application of the model to the Western Australia Wholesale Electricity Market that features no strategic bidding, and hence much less sensitivity to gas prices.

Figure 20 Annual electricity price Actual (black line), backcast (red) and the spread of outcomes driven by assumptions on strategic bidding percent



Actual monthly prices following the closure were a further $1-20/MWh above the minimal model – again highlighting relevant intra-year dynamics. Figure 21 shows the distribution of prices set by black coal units by month over 2017; curves further to the right indicate higher prices. Prices shifted dramatically in April (red line; the first month of Hazelwood closure) before returning to lower bands but still slightly higher than before the closure, which suggests participants found a new bidding equilibrium after the loss of capacity. The annual average estimates for price setting and strategic bidding behaviours may therefore mask some of the underlying dynamics in this case.

Figure 21 Cumulative histogram of prices set by Black coal by month in 2017

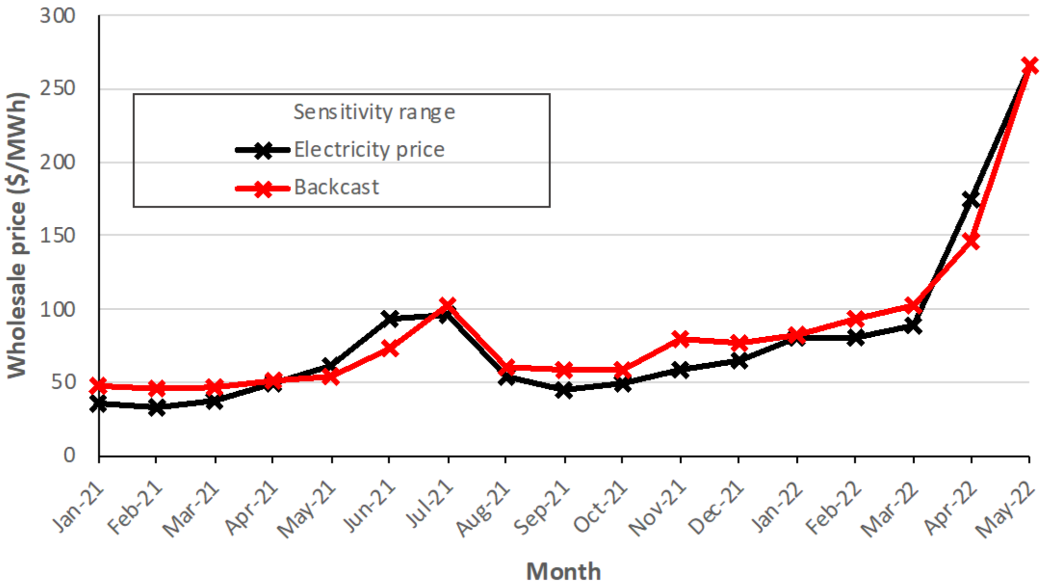


5.3 Use of the model in forward looking projections

In May 2022, fuel costs surged to record levels following the Russian invasion of Ukraine. Thermal coal prices rose to over $400/t, leading to marginal running costs above $150/MWh. Meanwhile, domestic natural gas prices rose to export parity, rising from an average of $9.16/GJ over 2021 to $16.29/GJ in April 2022 and $30.18/GJ in May 2022. On one day, regional prices cleared at $400/GJ, but with administered pricing reducing costs to consumers to “just” $40/GJ. At the same time, 8 GW of coal capacity (out of a fleet of 23 GW) was offline for maintenance.

Unsurprisingly, wholesale prices rose significantly as a result, averaging nearly $300/MWh in May 2022 (undercap price of $266/MWh). Figure 22 shows how the minimal GHR model can provide significant insight based on the range of plausible inputs. Average coal and gas prices were used, with price setting and strategic bidding parameters set at the average of 2016-2020 behaviours. The sensitivity range represents the highest and lowest settings (with 2021 behaviours driving the lower end). We find that wholesale prices are consistent with what would be expected based on (actual) fuel cost inputs plus historical levels of market power. However, had market power been reduced to 2021 levels (which seems plausible had the units of coal on outage been returned) wholesale prices could have been ~$75/MWh lower, a 28% reduction.

Figure 22 Model performance for 2022 year to date (May 2022)



The high accuracy of the backcast from only observed gas prices demonstrates the value of minimal models such as this, which can capture key market dynamics (even under extreme condition) without needing to specify detailed inputs. In practice, actual prices may be driven by alternative but functionally equivalent outcomes (from a pricing perspective). For example, the actual price setter may be different (e.g., hydro instead of coal) but will still be shadow pricing coal, with these underlying inputs in turn being driven by market concentration and the competitive demand.

6 Discussion and conclusions

From 2012 to 2020, wholesale prices were tightly linked to energy prices, with a GHR (slope) of 8.2 GJ/MWh. A minimal model of price setting behaviour confirms and explains this link in the NEM, but also highlights that there is variability year to year depending on projections, with annual Grid Heat Rates ranging from 5.5 to 9.8 GJ/MWh, and accurately producing the pricing dynamics.

We find that this minimal model is effective at explaining the key drivers of this relationship, namely the opportunities for black coal units to set price and exercise transient market power. To be clear, a minimal model will never replicate all the dynamics of a full market model dispatch. However, it allows insights that “black box” models struggle with, and we suggest it can be used to inform more sophisticated models, including market simulation bidding behaviours.

Although low wholesale prices in 2021 were initially regarded by some as evidence for a break in the relationship, we find that the 2021 GHR was not unusual in the history of the NEM. However, higher gas prices exacerbate the sensitivity of electricity prices to the GHR (i.e., to the amount of time gas directly and indirectly sets price) leading to a more visible separation than historically. The lower GHR was driven by higher output from renewable generation leading to greater competition amongst coal generators, lower gas usage, and less opportunity for participants to exercise market power. However, as evidenced by record high fuel and electricity prices at the start of 2022, and also historical plant closures, a higher GHR can be readily returned if the generation mix changes rapidly.

To be clear, shadow pricing of gas (or other) generators is an intrinsic feature of the NEM's energy-only market design. An implicit or explicit projection of the GHR is crucial to a view on long-term pricing, as gas prices currently drive 50-90% of pricing periods in the NEM through both direct and indirect methods.

A key question is how the GHR will evolve over time. Coal retirements will reduce the amount of time coal can set price, but would reduce competition in those peeriods and hence typically increase $\%S$. The impact on consumers will depend heavily on what takes over the price setting role. If it is renewables and energy storage, as recent trends suggest, it is credible that those portfolios will grow to be able to shadow price the marginal price setting technology, e.g., gas. This is not necessarily a result of market power – for energy limited technologies, a shadow price for energy will necessarily be factored into bid decisions. (In particular, this is explicit in fully automated battery bidding programs, that cooptimise output of multiple timescales.) In a similar vein, emissions constraints may hasten the decline of coal, but may also hasten strategic bidding behaviours by units that know natural gas units have limited run hours. More detailed market models may benefit from benchmarking against the minimal model presented here.

In the longer-term, reducing the impact on consumers of high gas prices relies on ensuring that competition remains at efficient levels. This requires better coordination of coal outages, rapid uptake of renewable generation, and a sharp focus on the level of horizontal integration of market participants. It seems likely that if these issues been addressed at the start of 2022 then wholesale prices could have been up to 28% ($75/MWh) lower. In the near-term, however, a GHR of 5-10 GJ/MWh is likely, and electricity consumers will remain exposed to swings in underlying commodity prices.

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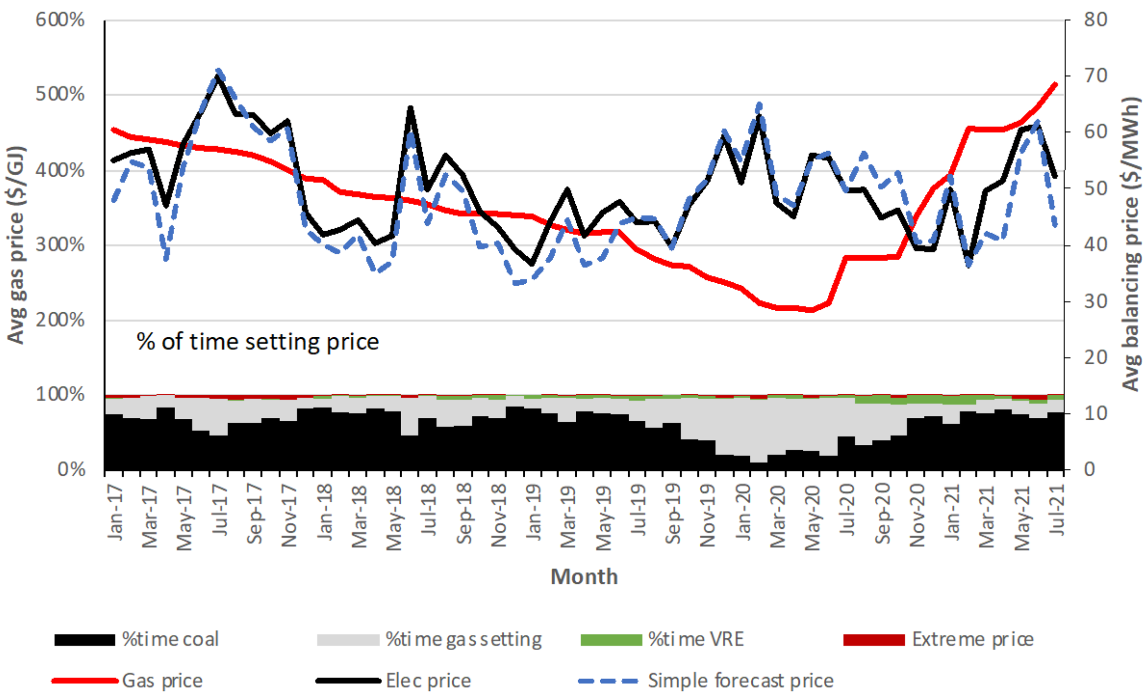
8 Appendix A - Western Australian Wholesale Energy Market

An interesting application of this model to other markets is shown in Figure 23 for Western Australian prices over the period 2017-2021. The spot gas price (red line) and electricity price (black line) appears to have only limited correlation. This is because the Western Australian Wholesale Energy Market (WEM) features a certificated capacity market with mandatory short-run marginal cost bidding in real-time spot market. This removes the ability of coal units to shadow price gas units ($\%S_{tech} = 0$ for all units), and therefore only the *direct* gas price setters contribute to the sensitivity. The area chart below the figure shows the projected $\%P \quad _{tech}$ calculated for each month[9]. With this input, and assuming the marginal cost for coal in all periods of XXX, the minimal model (Eq.1) still returns a high quality backcast can be provided (dotted blue line in Figure 23). This result should not be overly surprising – a cost-based market lends itself well to a load-block approach to pricing. It highlights, however, i) the explanatory power of the minimal model and ii) the significance that show bidding has on the NEM projection.

Figure 23 Results of applying the minimal model to the WEM



[9] Marginal price setter data is not available for the WEM, but estimated price setting technology can be derived from the spot price, given the mandatory marginal cost bidding.

9 Appendix B – Price setter methodology

9.1 Methodology for Price Setting Dataset

AEMO publishes price setter data, which records the units responsible for setting price in each period, for each region and market[10].

The price setting dataset records, for each market and region, all generators whose bids are responsible for setting the price in each period, and the marginal dispatch *Increase* for that unit to serve a marginal 1MW increase in demand. An example of the price setter data table is shown in Table 4 below. The full description of the table provided by AEMO is in Table 5.

Table 4 Sample of price setter data for 2 trading intervals

PeriodID	RegionID	Market	Price	Unit	DispatchedMarket	BandNo	Increase	RRNBandPrice	BandCost
1/01/2021 4:05	NSW1	Energy	28.43	CPP_4	ENOF	6	0.96	29.51	28.43
1/01/2021 4:05	QLD1	Energy	29.51	CPP_4	ENOF	6	1.00	29.51	29.51
1/01/2021 4:05	SA1	Energy	8.54	LYA1	ENOF	3	0.36	8.95	3.18
1/01/2021 4:05	SA1	Energy	8.54	LYA4	ENOF	3	0.36	8.95	3.18
1/01/2021 4:05	SA1	Energy	8.54	LYA2	ENOF	3	0.24	8.95	2.19
1/01/2021 4:05	VIC1	Energy	8.95	LYA1	ENOF	3	0.37	8.95	3.33
1/01/2021 4:05	VIC1	Energy	8.95	LYA4	ENOF	3	0.37	8.95	3.33
1/01/2021 4:05	VIC1	Energy	8.95	LYA2	ENOF	3	0.26	8.95	2.29
1/01/2021 4:10	NSW1	Energy	30.89	MP2	ENOF	3	1.00	31.89	31.89
1/01/2021 4:10	QLD1	Energy	31.82	MP2	ENOF	3	1.03	31.89	32.85
1/01/2021 4:10	SA1	Energy	8.69	LYA2	ENOF	3	0.25	8.95	2.22
1/01/2021 4:10	SA1	Energy	8.69	LYA1	ENOF	3	0.36	8.95	3.23
1/01/2021 4:10	SA1	Energy	8.69	LYA4	ENOF	3	0.36	8.95	3.23
1/01/2021 4:10	VIC1	Energy	8.95	LYA1	ENOF	3	0.37	8.95	3.33
1/01/2021 4:10	VIC1	Energy	8.95	LYA4	ENOF	3	0.37	8.95	3.33
1/01/2021 4:10	VIC1	Energy	8.95	LYA2	ENOF	3	0.26	8.95	2.29

This dataset is used to calculate the percentage of time, and at what level, the price is set by each fuel type in each region. In some intervals there will be multiple generators involved in setting price, for example when generators are tied in a constraint, in which case these generators will each have a small *Increase* value. It is also possible for generators to have a negative *Increase* value, indicating that the optimal dispatch involves those generators reducing their output, in order satisfy network limitations or security constraints. For simplicity, units with an *Increase* value less than 0.05 in a period are excluded from the analysis as they do not materially contribute to price setting in that period.

[10] Published on nemweb.com.au

The price setting fraction attributable to each fuel type is then calculated for each *PeriodID* and *RegionID*. In each period and region, the number of units setting price for each fuel type is calculated (excluding units as described above), and then divided by the total number of units involved in price setting in that period and region. All individual units involved in setting price in an interval are weighted equally and all periods are weighted equally. This prevents periods with many price setters being unduly weighted over periods with a single price setter. This calculated 'price setting fraction' is then be aggregated across days and months for each region and fuel type.

Table 5 NEMDE price setter data format

Period ID	The five-minute period for which data is displayed in the other columns.
Region ID	The ID of the region for which data is displayed in the other columns.
Market	The market the unit is trading into.
Price	The market price in $/MWh.
Unit	For trade band variables, this is the unit that the trade band belongs to. For MNSP band variables it is the name of the interconnector and the region that the band belongs to. For tbslack1 and tbslack2 variables it is a representation of the priced-tied trade bands. For generic constraint deficit and surplus variables it is the constraint name. For deficit product and surplus generation variables you will see the name of the region and market.
DispatchedMarket	For trade band variables, this is the market that the trade band is for. For MNSP band variables it is the ENOF. For all other variables, it is the name of the variable.
BandNo	For trade band or MNSP band variables this is the band number. For all other variables it is blank.
Increase	An amount in MW, rounded to eight decimal places. For the Energy market, this is the marginal increase in band dispatch or constraint violation for a marginal 1MW increase in the energy demand for this region and market. For any FCAS market, this is the marginal decrease in band dispatch or constraint violation for a marginal 1MW decrease in the FCAS demand for this region and market. If the price-setting energy bands or energy-violations belong to a different region, the amount of increase may also take into account inter-regional losses.
RRNBandPrice	An amount in $/MWh, rounded to eight decimal places. For energy and FCAS bands, this is the band prices, as referred to its RRN. For all other variables this is the constraint violation penalty (CVP) price.
BandCost	An amount in $/hour, rounded to eight decimal places. It is the "Increase" figure multiplied by the RRN band price.

Source: AEMO

9.2 Methodology for estimating coal SRMC

The fuel cost for coal generators has been estimated using the Newcastle Coal Index, the main reference price for thermal coal contracts in Asia and typically used as the reference export coal price in eastern Australia. It is the spot delivery price for Free On Board coal at the port of Newcastle, measured in metric tonnes[11]. Specific coal generators' exposure to this

[11]https://www.globalcoal.com/files/Methodologies/Eng/gC_NEWC_Index_Methodology_v1l.pdf

export price varies depending on the extent their supplying coal mines can export spare coal such that the export price (net of any transport costs) acts as an opportunity cost price. This is because a generators decision to increase or decrease electricity generation should be reflecting the marginal cost of this coal. The table below summarises which stations are exposed to the export market.

Table 6 Export exposed status of black coal stations in the NEM

State	Power station	Physical export exposure
NSW	Eraring	**Yes**
	Vales Point	**Yes**
	Bayswater	**Yes**
	Liddell	**Yes**
	Mt Piper	**Yes**
QLD	Gladstone	**Yes**
	Callide B and C	**Yes**
	Kogan Creek	No
	Stanwell	**Yes**
	Tarong and Tarong Nth	No
	Milmerran	No

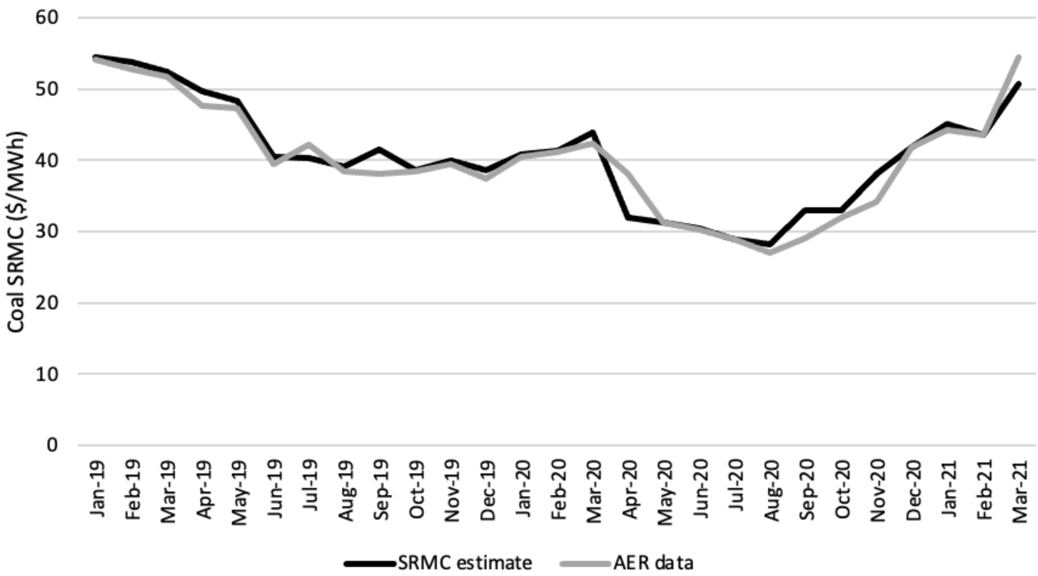
Source: Frontier Economics (2019)

Newcastle Coal Index historical monthly prices were used, these monthly prices were gathered in USD/tonne. The Reserve Bank of Australia's monthly exchange rate[12] was used to convert to AUD/tonne. The calorific value of thermal coal in Australia varies as the coal varies in quality. The Newcastle coal index standard specification is 6,000kcal/kg, equivalent to 25GJ/tonne. While thermal coal used in Australian power generation varies between 21-27GJ/tonne[13] we have used 25GJ/tonne to again reflect the marginal cost of coal. Coal plants are modelled with a 10GJ/MWh heat rate. These assumptions for coal short run marginal cost have been validated against reporting from the Australian Energy Regulator (AER), as shown in the figure below.

[12] https://www.rba.gov.au/statistics/historical-data.html

[13] https://www.energy.gov.au/sites/default/files/Guide%20to%20the%20Australian%20Energy%20Statistics%202020.pdf , Table 5.4

Figure 24 Black Coal SRMC calculated cost (black line) and AER estimation (grey line)



Source: AER State of the Energy Market 2021