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The carbon tax and the crisis in Australia's National Electricity Market[☆]

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ABSTRACT

Australia faced a severe energy crisis in 2022, which prompted the Australian Energy Market Operator to halt in National Electricity Market operations from June 15 to June 24. In this study, which examines half-hourly data from Australia's National Electricity Market between 2010 and 2016, we aim to demonstrate the notable and intended consequences of the carbon tax, which was enacted in 2012 and repealed in 2014. Our findings show that this tax had a significant impact on wholesale prices. It also induced substitution effects in the generation mix. If these effects had persisted, the electricity generation landscape in 2022 would have been different. Specifically, the economic feasibility of coal would have decreased and that of gas would have increased. As a result, the composition of electricity generating capacity leading up to the 2022 crisis would have been altered.

1. Introduction

Australia experienced a significant energy crisis in 2022, which was the most severe in this century. The crisis garnered widespread attention in the media, and was the first time that many Australians were urged by the government to reduce their electricity usage. Energy retailers struggled to cope, which caused some businesses to fail, and consumers were instructed to limit electricity-intensive activities to specific times, such as washing dishes after 10 pm. Also, generators were compelled to operate in a controlled pricing market with unplanned closures. The next section will delve into the detailed factors that prompted the Australian Energy Market Operator to suspend the National Electricity Market (NEM) from June 15 to June 24, 2022.

This paper utilizes half-hourly data from Australia's NEM spanning from 2010 to 2016 to demonstrate that the carbon tax, which was introduced in 2012 and repealed in 2014, had a significant impact on wholesale prices. It also had an impact—as intended—through its induced substitution effects.

Specifically, the carbon tax incentivized the replacement of black and brown coal-fired generation with gas and hydro. If these effects had persisted, the electricity generation landscape in 2022 would have been altered leading up to the market crisis. By focusing on the carbon tax's influence on pricing and the generation mix throughout the day,[1] we provide evidence that the decision to repeal the tax was likely a costly policy mistake.

Australia's carbon price package (the 2011 Clean Energy Bill) introduced, along with a carbon price, the Energy Security Fund. This initiative granted free permits to electricity generators, provided that those significantly impacted by the carbon price published Clean Energy Investment Plans. These plans detailed their strategies for reducing pollution and meeting power system reliability standards. The program also committed to negotiating the closure of roughly 2000 megawatts (MW) of highly polluting generation capacity by 2020.[2]

Our study centers on examining the influence of the carbon price package on the pricing and generation mix throughout the day. This evaluation aims to address two primary aspects: first, the impact of increased marginal costs on fossil fuel generators, and second, the potential closure (whether temporary or permanent) of coal generators.

It is important to note that while some closures occurred temporarily during the carbon tax period and resulted directly from the carbon tax package, all permanent closures were announced within a single comparator period—the post-carbon tax package period—or happened after the time frame analyzed. Also, the effect of these closures on prices is uncertain. Referring to the findings of Gonçalves and Menezes (2022b), who investigated the price impact of the Hazelwood coal plant

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[1] Bushnell and Novan (2021) pioneered the approach of estimating the market impact of renewables throughout the day.

[2] For a general description of the Clean Energy Bill 2011, see Gillard (2011). For a list of the two tranches of compensation received by coal generators (cash payments and free permits), see Table 1 in Fraser et al. (2023).

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closure, it seems reasonable to consider that these closures might have contributed to a rise in NEM prices—albeit potentially to a lesser degree than the price impacts of Hazelwood closure, due to the size of that power plant and the unanticipated nature of the closure.

Australia's carbon pricing mechanism came into effect on 1 July 2012, at a rate of $23 per tonne of CO2 equivalent for the financial year 2012–2013. The carbon tax was initially set to increase to $25.40/tCO2e for the financial year 2014–2015, with the intention of transitioning to an emissions trading system by July 2015. During the initial 3 years—the fixed-price period—the scheme affected 500 of Australia's largest polluting companies, including electricity generators (Commonwealth of Australia, 2011). However, the Liberal-National coalition, which had campaigned against the carbon tax, successfully repealed it on 17 July 2014, after winning the government in the 2013 federal election.

The carbon tax package was expected to decrease Australia's carbon emissions to 5% below 2000 levels and achieve a reduction of 80% of 2000 levels by 2050. Furthermore, it aimed to increase the share of large-scale renewable energy (excluding hydropower) by 18 times and generate 40% of electricity from renewable sources (including hydropower) by 2020 (Commonwealth of Australia, 2011). Contrary to these goals, however, after winning the government in 2013, the coalition legislated to reduce the large-scale renewable energy target by 20% from 41,000 GWh per year to 33,000 GWh by 2020. Since the 2013 election, successive coalition governments have introduced various out-of-market mechanisms, such as co-financing and investment by the Clean Energy Finance Corporation and changes to the Renewable Energy Target.[3] The large-scale renewable energy target was expected to create most of the renewable energy needed by 2020 (Tomaras, 2016).

The proliferation of out-of-market mechanisms, combined with uncertainty surrounding climate change policies, severed the connections between NEM prices, investment requirements, and system operations that characterized the NEM's functioning until the mid-2010s.[4] These severed links, along with the increase in the penetration of renewables without a proportional increase in firming capacity, are significant factors that contributed to the current NEM crisis. By examining the impact of the carbon tax, we aim to shed light on possible outcomes had the carbon tax not been repealed.

To quantify the impact of the carbon tax on (wholesale electricity) prices and the energy mix, we adopt an econometric regression model for each half-hour of the day. In doing so, we compare the prices (and energy mix) during the carbon tax period (2012–2014) with a period of roughly the same duration before (2010–12) and after (2014–16) it was in place. Our econometric approach allows us to control for a range of variables, including fuel prices, that also influence electricity prices and the energy mix.

In terms of prices, our findings suggest that the carbon tax led to increased electricity prices—on average, between $26.2 and $34.1/MWh. Furthermore, when the tax was repealed, electricity prices decreased by about the same order of magnitude by which they had increased when the tax was introduced. More interestingly, we find that the carbon tax induced a significant change in the energy mix, with a reduction in black and brown coal generation that was compensated for by natural gas and hydro generation. However, when the carbon tax was repealed, black and brown coal generation increased by more than they had decreased after the tax was introduced. This "over-recovery" had a rather significant impact on natural gas generation, which decreased by substantially more than it had increased when the carbon tax was introduced. By contrast, the reverse was true for hydro generation. Therefore, our results suggest that in the post-carbon tax period, coal and hydro-based generation became relatively more important than before the carbon tax, whereas the reverse is true for natural gas generation. That is, repeal of the carbon tax had profound consequences for the energy mix in the NEM.

The paper is organized as follows. Section 2 describes the background of the NEM that led to the market suspension of June 2022. Section 3 reviews the literature, including previous studies that have examined the impact of the carbon tax on the NEM. Section 4 describes the data and Section 5 presents our empirical approach. Section 6 analyzes the impact of the carbon price on prices and the generation mix, and Section 7 concludes with a discussion of the potential impact of the repeal of the carbon tax on the future generation mix of the NEM.

2. Background of the NEM and the 2022 energy crisis

The NEM, which was established in December 1998, is one of the world's largest interconnected power systems. It comprises approximately 150 major power stations with a total of around 240 plant units. The transmission network spans roughly 40,000 km of high voltage power lines and delivers electricity to large energy users and distribution networks. The competitive retail market serves about 10 million residential, commercial, and industrial energy consumers.[5]

In the NEM, all electricity is traded on the spot market within an energy-only gross pool. Prices and the quantity of electricity generated by each power station are determined through the interaction of bids made by generators and overall system demand, excluding household photovoltaic (PV) generation. Every 5 min, a dispatch price is set for each region of the NEM,[6] which corresponds to the bid of the marginal generator. Electricity demand can be met by generation in one or more regions, and the interconnection between regions allows for the transfer of energy from lower-price regions to higher-price regions, which creates price linkages. However, prices no longer co-determine when the interconnectors' capacity is reached.

This is a high-level characterization of how the wholesale market operates.[7] However, in practice, the market operator employs a security-constrained economic dispatch algorithm, known as the NEM dispatch engine (NEMDE). This algorithm tackles a complex linear optimization problem, with the aim of achieving the most cost-effective balance between power supply and demand while ensuring the power system's security and reliability. The engine addresses thousands of constraints that mirror the physical limitations inherent in the power system.[8]

Beyond the physical wholesale market, there is a sophisticated derivative market that interlinks the economic facets of the physical power system with investment strategies and resource sufficiency.

[3] The Renewable Energy Target operates by allowing both large-scale power stations and owners of small-scale systems to generate certificates for every MWh of power they produce. These certificates come in two types: large-scale generation certificates and small-scale technology certificates. Electricity retailers, who supply power to households and businesses, purchase these certificates to fulfill their legal obligations under the Renewable Energy Target. The purchased certificates are then submitted to the Clean Energy Regulator. This mechanism establishes a market that offers financial incentives to both large-scale renewable energy power stations and owners of small-scale renewable energy systems. For more information, refer to the Clean Energy Regulator's website: https://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target

[4] See, for example, Simshauser (2019a,b) and Gonçalves and Menezes (2022a,b).

[5] See, for example, Australian Energy Regulator (2018), Chapter 2.

[6] There are five regions in the NEM: New South Wales (NSW), Queensland (QLD), South Australia (SA), Tasmania (TAS), and Victoria (VIC).

[7] See, for example, https://aemo.com.au/-/media/files/electricity/nem/national-electricity-market-fact-sheet.pdf and https://www.aemc.gov.au/sites/default/files/content//Five-Minute-Settlement-directions-paper-fact-sheet-FINAL.PDF.

[8] Detailed information on the least-cost, security-constrained dispatch process followed by the market operator can be found at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/dispatch-information.

The NEM has arguably been successful in promoting allocative and dynamic efficiency.[9] Notably, the NEM's high market price cap (currently at A$16,600/MWh) has prevented the emergence of the "missing money" problem that is often seen in other electricity markets worldwide.[10] However, this success has been disrupted. The link between NEM prices, investment requirements, and system operations has been severed due to out-of-market mechanisms, such as the renewable energy target.[11] These severed links, coupled with overreliance on aging coal power plants, contributed to the NEM's suspension in June 2022 and the ongoing challenges it faces.

In June 2022, significant events unfolded in the Australian energy market. During this period, the Australian Energy Market Operator (AEMO) decided to suspend the spot market in all regions of the NEM from June 15 to June 24. Under this suspension, prices were determined based on the published market suspension pricing schedule. Generators were instructed to supply capacity to the market, and compensation payments were provided to generators whose cost of supplying electricity exceeded the price cap. This ensured that they would not suffer financial losses.[12]

The primary reason cited by AEMO for the market suspension was the critical shortage of power generation supply, which rendered it impossible to run the dispatch algorithm while adhering to all technical constraints. To avoid load shedding, the AEMO activated an additional 5 Gigawatts (GW) of generation capacity outside the market. The immediate trigger for the market suspension was the application of the price caps, as detailed below, and subsequent significant unplanned outages. However, an important underlying cause of the crisis included the overreliance on aging coal power plants.[13]

We will now describe the events leading up to the market suspension. On June 12, electricity prices in Queensland soared to a cumulative high price threshold of A$1,359,100. This threshold was reached over a span of 7 days and equated to the spot price continuously being set at the market price cap of $15,100/MWh for 7.5 h. Consequently, the administrative price cap of $300/MWh was triggered. As a result of this trigger, approximately 3 GW of thermal generation became unavailable due to unforeseen events. While the market rules stipulate that plants running at costs that exceed revenue can be compensated afterward, numerous plants listed their capacity as unavailable. This action disrupted AEMO's dispatch engine and led to a market suspension.

Thermal generators faced increased fuel costs due to high domestic gas prices, elevated international coal prices as a result of the conflict in Ukraine, and difficulties in sourcing coal caused by heavy rain that affected open-cut mines in New South Wales and Queensland. Furthermore, numerous generators were undergoing planned maintenance, which is typical during the shoulder season, while demand substantially rose due to an unexpected drop in temperatures. These factors were further complicated by scheduled transmission outages and periods of low wind and solar power output.[14]

In essence, the primary factors behind the crisis concerned critical outages at aging coal plants, which made additional gas generation necessary to compensate for the coal plant failures. A significant issue then arose due to the discrepancy between the gas market price cap set at $40/GJ and the electricity market price cap at $300/MWh. To illustrate, a gas turbine consumes between 10–12 gigajoule (GJ) per MWh.[15] However, since 10 multiplied by $40/GJ amounts to $400/MWh, this surpasses the $300/MWh cap set in the electricity market.

The market's return to operation was marked by consistently high electricity prices. To address this, caps were imposed on the wholesale price of natural gas and coal in December 2022, set at A$12 per GJ and A$125 per tonne, respectively, for a period of 1 year. These price caps caused a return to historical electricity prices in the first quarter of 2023, with an average price of A$83 per MWh. As a result of the caps on thermal coal prices, black coal generators in New South Wales and Queensland increased their offer volumes at lower price bands, which reduced the average price set by black coal generators when they act as the marginal price-setter.[16]

However, the crisis is far from over. The AEMO forecasts that reliability gaps will emerge starting in 2025. These gaps will continue to widen, with all mainland states in the NEM projected to breach the reliability standard from 2027 onward. Also, approximately 13% of the NEM's total capacity is expected to retire, including at least five coal power stations.[17]

The planned closure of the 52-year-old Liddell Power Station in New South Wales in April 2023 exemplifies the challenges faced by the NEM. Despite having a listed maximum output of 2.2 GW, one of its four units was already closed in 2022; this reduced output to 1.65 GW.[18] Moreover, due to its age, Liddell has consistently been unable to generate its maximum capacity. In 2022, the power station's operator offered a maximum capacity of 1.25 GW to the spot market, but this was available only during a small percentage of periods. The average capacity available in 2022 was only 800 MW.[19]

Nevertheless, as noted by Gilmore and Nelson (2023), peak electricity consumption in New South Wales is around 14 GW—and without Liddell, there is approximately 13.5 GW of coal, gas, and hydro generation capacity available. When considering the existing wind and solar capacity, as well as imports from Victoria and Queensland via transmission lines, it seems that there is enough capacity to meet peak demand. However, the reliability of the remaining coal-fired power stations is becoming increasingly problematic, as evidenced by the June 2022 market crisis. To understand the potential magnitude of the impact of unanticipated unavailability of coal-fired power stations, the unexpected closure of Hazelwood, a large brown coal power plant (1.6 GW) in Victoria, had a market impact of A$6,527.4 million, as documented in the work of Gonçalves and Menezes (2022b).

Although the goal of this paper is not to identify the driving forces of the 2022 crisis, our econometric estimates allow us to argue in Section 7 that continuation of the carbon tax could have enabled a smoother energy transition. The precise energy mix that would have ensued had the carbon tax continued is challenging to ascertain definitively, primarily due to several factors. Notably, the planned transition from a fixed carbon price to a floating price mechanism would have introduced considerable uncertainty, impacting investment decisions across various technologies, such as wind power. Additionally, differing technology costs between the initial period of 2012 to 2014 and the subsequent years leading up to 2022 further complicate predictions. Furthermore,

[9] See, for example, Simshauser (2019c).

[10] The missing money problem refers to the fact that imperfections in wholesale energy-only electricity markets, such as market price caps, result in generators' failure to earn net revenues sufficient to support investment in a least-cost portfolio of generating capacity and satisfy consumer preferences for reliability. See, for example, Joskow (2007) and Joskow and Tirole (2007).

[11] See, for example, Simshauser (2019b) and Gonçalves and Menezes (2022b).

[12] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports.]

[13] Australia's gas and coal-fired power plants broke down an average of once every 3.2 days over the 2 years through December 2019. See https://reneweconomy.com.au/australias-coal-and-gas-plants-are-breaking-down-every-three-days-34744.

[14] See AEMO (2022).

[15] We thank a referee for providing this figure.

[16] Simshauser (2023) estimated that the price caps had the effect of moderating forecast electricity tariff increases from 35% to 16.5%. Pourkhanali et al. (2024), however, showed that their impact was not uniform across the NEM with a reduction in wholesale prices in Queensland and New South Wales, but no positive effect in Victoria.

[17] See AEMO (2023).

[18] See https://www.huntervalleynews.net.au/story/7682841/agl-begins-first-step-of-liddell-power-station-closure/.

[19] See https://wattclarity.com.au/articles/2023/01/farewell-liddell/.

as elucidated later in this paper, while the rapid adoption of solar energy from 2018 onward has significantly undermined the economics of coal generation, it would have been consistent with the potential scenario of gas assuming a more prominent role in the ongoing energy transition. This is because gas generators, due to their flexibility, stand to gain from higher prices resulting from increased grid demand during peak hours in the afternoon as solar power distribution wanes and utility-scale solar supply disappears.

3. Literature review

A substantial body of literature examines the effects of the European Union's Emission Trading Scheme (EU ETS) on electricity prices. These studies have consistently identified pass-through rates ranging from 30% to 100% in the electricity sector.[20]

Research on the market impact of Australia's carbon pricing mechanism is relatively scarce. Most studies conducted before its implementation employed various modeling approaches to forecast the potential effects of the carbon tax. These studies projected pass-through rates ranging from 17% to 400%.[21] An exception is Leslie (2018), who estimates a pass-through rate closer to 100% for the Western Australian market.

Although Fraser et al. (2023) do not provide an estimate for the average pass-through for the NEM—which would require accounting for the merit order and emissions intensity of the entire grid—they find that, on average, the wholesale electricity price rose by 90% of the increase in carbon costs for coal generators. Their methodology involved meticulous estimation of the change in profits (disregarding fixed costs) as a result of the carbon tax package. Their detailed study also exemplifies the event study approach we employ. In their analysis, the authors compare generator profits before and after introduction of the carbon price, rather than estimating counterfactual generation and prices in the absence of this carbon pricing mechanism.

Among the limited number of empirical studies conducted after implementation of the carbon pricing mechanism, Nazifi (2016) examined the impact of a carbon tax from July 2010 to October 2013, using monthly data while controlling for coal and natural gas prices as well as electricity demand. The estimated pass-through rates for all regions within the NEM ranged from 101% to 132%. In contrast to Nazifi's approach, we assess the carbon tax's impact on the price distribution throughout the day and its influence on the generation mix. By doing so, we provide insights into how the carbon tax affected the dynamics of the market. Another noteworthy contribution to the literature is that of Maryniak et al. (2019), who specifically examined the impact of the carbon tax on electricity futures contracts. Their findings revealed expected pass-through rates ranging from 67% to 150%.

Nazifi et al. (2021) conducted a study that closely aligns with our own research. They also examined the effects of the carbon tax on the NEM using an econometric model that considers various factors such as short-run marginal costs and electricity demand. Our study shares a similar sample period, from July 2010 to June 2016, which allows us to assess any enduring impacts of the carbon tax following its repeal in July 2014. However, there are several notable differences between our approaches.

First, Nazifi et al. (2021) aimed to estimate the pass-through rate and achieved this by measuring the disparity between volume-weighted daily average wholesale electricity spot prices and generators' fuel costs. Conversely, our primary focus is evaluating the influence of the carbon tax on the price distribution throughout the day and the generation mix. As we will see in Section 4, there is significant intraday variability in both and, therefore, it is certainly interesting to understand whether there are differential effects of the carbon tax throughout the day. We employ these estimates to speculate on potential outcomes had the carbon tax not been repealed.

Second, Nazifi et al. (2021) calculated pass-through rates separately for four NEM regions (NSW, QLD, SA, and VIC), whereas we combine the NEM data and employ dummy variables (in a fixed-effects panel data regression) to represent the different NEM regions. By pooling the data, we acknowledge the interconnectedness of the regions and account for the connectivity in our analysis.

In their study, Nazifi et al. (2021) discovered significant variations in average pass-through rates across the four regions, ranging from 97% in Victoria to 290% in QLD. While we do not compute pass-through rates in the same manner, we use our price impact estimates of the carbon tax to calculate NEM-wide pass-through rates for different generator types. Consequently, we find average pass-through rates for black coal that align more closely with those anticipated in a competitive market.

Also, Nazifi et al. (2021) observed that spot electricity prices remained high even after repeal of the tax. Their estimates indicated an increase in electricity prices after the carbon tax repeal, ranging from \$19.24/MWh in SA to \$20.02/MWh in QLD. In contrast, our findings indicate that average prices largely returned to pre-carbon tax levels. This disparity can be attributed to Nazifi et al.'s (2021) use of dummy variables for both the carbon tax period and the post-period. By doing so, they overestimate the post-carbon tax impact, since the dummy variable for the post-carbon tax period encompasses the combined effects of the pre-carbon tax period and the period during the carbon tax implementation. To avoid this overestimation, we specify separate dummy variables for the pre-carbon tax and post-carbon tax periods in our analysis.

4. Data description

We use half-hourly data for the 2 full years before introduction of the carbon tax and for the 2 full years after the carbon tax was repealed. We therefore focus on three time periods: July 1, 2010–June 30, 2012 (which we refer to as 'before carbon tax'); July 1, 2012–July 17, 2014 (which we refer to as 'carbon tax'); and July 18, 2014–July 17, 2016 (which we refer to as 'after carbon tax'). These three time periods are roughly equivalent in terms of duration (close to 2 years) and allow us to understand the likely effects of the carbon tax compared with the previous or subsequent period. Indeed, these time periods are sufficiently close (in time) to the carbon tax period that it is reasonable to assume that the main price drivers did not change significantly (apart from the carbon tax itself). Similarly, these time periods are sufficient to control for seasonality—e.g., summer vs. winter effects. Furthermore, the introduction of utility scale solar in the NEM occurred in 2015 (see, for instance, Gonçalves and Menezes, 2022a), which implies that during the 'after carbon tax' period, solar generation was at its very start, with low penetration rates and, presumably, low impact on prices.

Fig. 1 displays the average price in each of the five states for each half-hour slot before, during, and after the carbon tax. With the exception of Tasmania, average prices for most half-hour slots were higher during the carbon tax period than in the periods before and after its implementation. Also, for all states and for most half-hour slots, average prices after the carbon tax were higher than before its implementation, which may indicate a possible trend effect that needs to be accounted for.

Fig. 2 displays the average weight of each of the main types of electricity production in each half-hour before, during, and after the carbon tax. For most half-hourly slots, the weight of brown and black coal in total generation was lower during the carbon tax period than the periods before and after its implementation. By contrast, the weight of natural gas and hydro was higher during the carbon tax period, which suggests that the carbon tax induced a shift in generation from more

[20] See, for example, Gulli and Chernyavska (2013); Hintermann (2016); and Fabra and Reguant (2014).

[21] For a survey of the results, see Nelson et al. (2012).

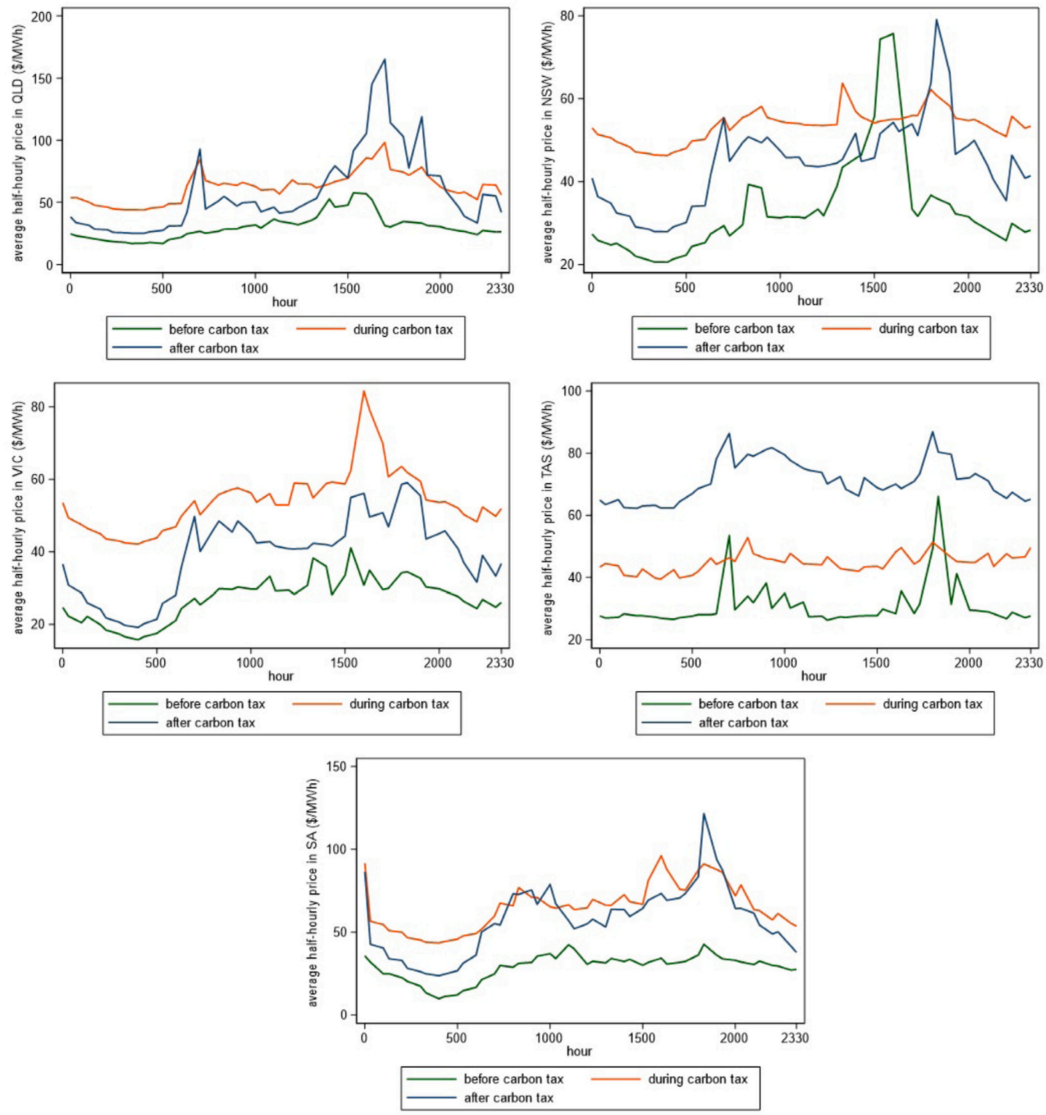

Fig. 1. Average wholesale prices in each state before, during, and after the carbon tax by half-hourly slots.

polluting energy sources (coal) toward less polluting ones (natural gas and hydro). Throughout this period, wind generation was increasing; this explains the observed pattern for the weight of wind in total generation. Also, this adds to our earlier observation that a trend effect should be introduced in our analysis.

5. Empirical approach

We aim to understand and quantify the impact of the carbon tax on half-hourly NEM prices. We adopt an event study approach (see Campbell et al., 1997, or Kothari and Warner, 2007, in the field of finance). Our baseline model aims to explain NEM prices in a scenario in which the carbon tax was not introduced. The price impact of the carbon tax is then obtained as the difference between observed and predicted prices. Observed prices are those that prevailed before and after the carbon tax, whereas predicted prices are those that we predict would have prevailed during the carbon tax period if the carbon price had not been introduced.

Gonçalves and Menezes (2022b) used a similar approach to estimate the price impact of the Hazelwood coal plant closure in Victoria in 2017. While Gonçalves and Menezes (2022b) estimated the impact of closure on the distribution of prices throughout the day, in this paper, we focus on the impact of the introduction of the carbon tax both on the distribution of prices and the generation profile for each type of fuel for each half hour of the day.

As outlined above, NEM prices are set on a half-hourly basis for each state. Define each half-hour as 'hh'. We examine three time periods (defined above): before, during, and after the carbon tax. For each half-hour and each state during those three time periods, we observe NEM prices. Define $t = 1$ day (this notation is helpful, because our regression uses lagged variables) and define y to be the year (see below for further explanation). We estimate a (state) fixed-effects model separately for each half-hour of the day (a total of 48 regressions):

$$\begin{aligned} P_{hh,s} =& \beta_{hh}^{before}.Before + \beta_{hh}^{after}.After + \alpha_{hh,s} + \\ &+ \beta_{hh}^{ngas}.NaturalGas_{hh} + \beta_{hh}^{wind\_curtail}.Wind\_Curtail_{y} + \\ &+ \beta_{hh}^{rainNSW}.RainNSW_{d} + \beta_{hh}^{rainNSW}.RainTAS_{d} + \\ &+ \beta_{hh}^{month}.Month + \beta_{hh}^{month\{2}.(Month)^{2} + \\ &+ \sum_{t=1}^{6} \theta_{hh,t}.P_{hh-t,s} + \gamma_{hh}.\mathbf{X}_{hh,s} + \varepsilon_{hh,s} \end{aligned} \tag{1}$$

$Before$ is a dummy variable that takes the value of 1 for the before carbon tax period (July 1, 2010–June 30, 2012) and 0 otherwise. $After$ is a dummy variable that takes the value of 1 for the after

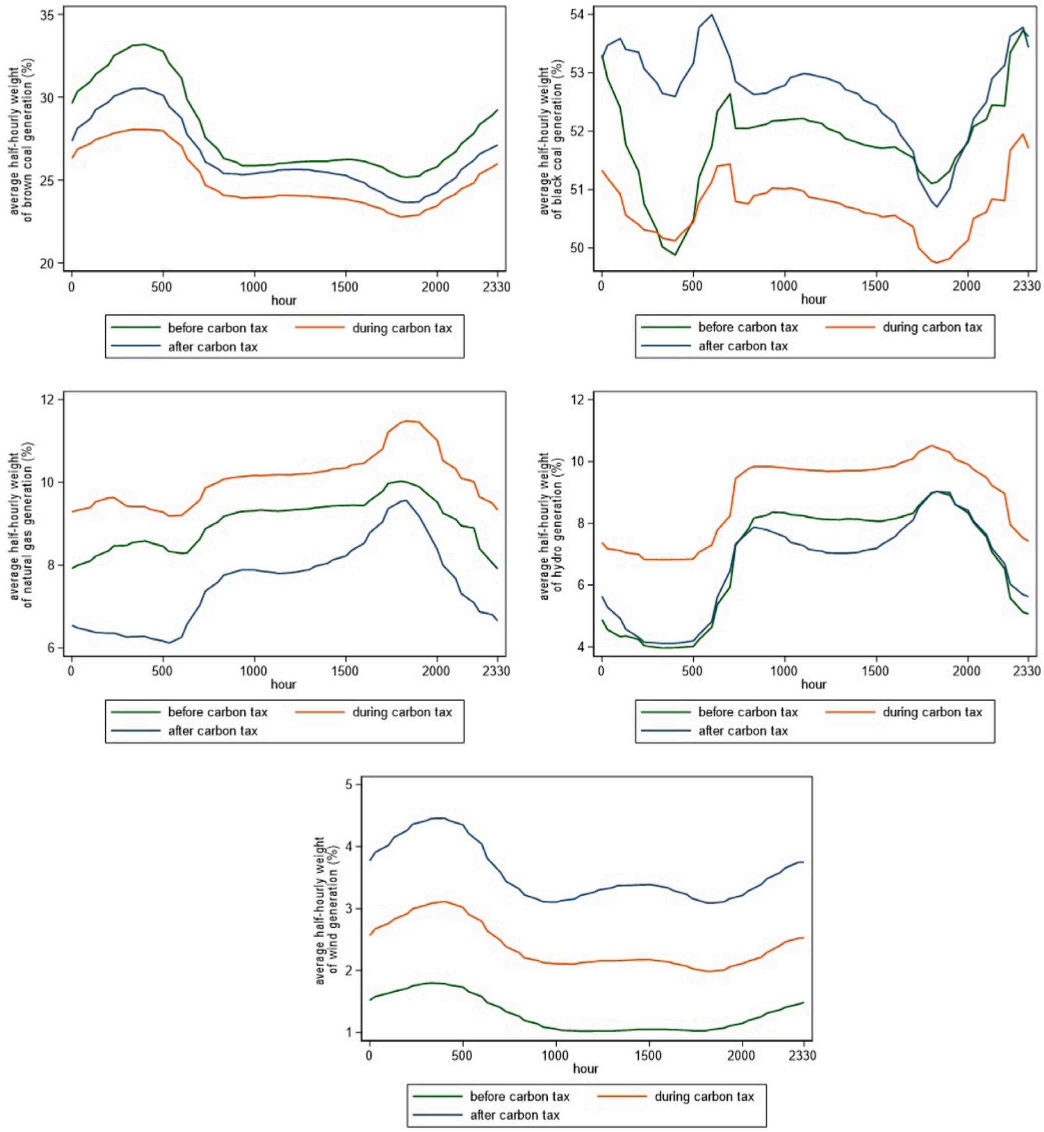

Fig. 2. Weight of each type of electricity production before, during, and after the carbon tax by half-hourly slots.

carbon tax period (July 18, 2014–July 17, 2016) and 0 otherwise. These are the main variables of interest, and they are constructed such that the carbon tax period is our baseline—that is, we will estimate price differences between the carbon tax period and the before carbon tax period, as well as between the carbon tax period and the after carbon tax period. The estimated coefficients of these two variables will allow us to estimate the price changes that can be attributed to the introduction of the carbon tax (taking into account all other explanatory factors).

The dummy variable $\alpha_{hh,s}$ is state-specific and aims to capture possible (state) fixed effects on prices. $NaturalGas$ is the Declared Wholesale Gas Market (DWGM) price, which is available on an intraday basis in 5 scheduled intervals. The natural gas price for each schedule interval in each day was appropriately matched with each half-hour and day in our dataset. $Wind\_Curtail$ is a yearly variable that contains the percentage of wind production that was curtailed. It is a proxy for the lower wind production inserted into the NEM because of system limitations, and was obtained from Srianandarajah et al. (2022, Table 4). $RainNSW$ and $RainTAS$ represent the daily rainfall in two locations—one in New South Wales and the other in Tasmania—that are close to major hydroelectric plants. The introduction of these variables in our regression aims to control for the opportunity cost of water, although it should be noted that approximately one-third of Australia's hydroelectric capacity is pumped hydro—in which case rainfall is less relevant for supply availability. In combination, $Month$ and $(Month)^2$ aim to account for the possibility of a nonlinear trend in NEM prices. $Month$ is an (increasing) integer variable with the number of the month in our dataset, from the start to the end of our sample period (total of 73 months).

As in Gonçalves and Menezes (2022b), we deliberately exclude coal prices as a possible explanatory variable. Gonçalves and Menezes (2022a) counterintuitively report a negative impact of the daily price of coal on electricity prices. A strategic effect may be at the root of this result, because many coal generators own nearby coal mines or have entered into long-term contracts for coal supply.

The vector $\mathbf{X}_{hh,s}$ includes additional relevant explanatory variables. $XD_{hh,s}$ denotes the excess demand for electricity in half-hour hh in state s—that is, the difference between total demand in state s and its own electricity production. When $XD_{hh,s}$ is positive, electricity is being imported from other states via the interconnectors; when it is negative, that state is exporting electricity. TG_{hh} is the electricity production in all states in half-hour hh. It aims to capture long-term trends in demand that may impact prices. We explain below that we also include 3 lags of this variable in the regression. Because our regressions are for each half-hour, we therefore include the total production in the same half-hour of the previous 3 days. Finally, we also include the dummy variables weekday and month to capture weekday or month fixed effects.

Csereklyei et al. (2019) and Gonçalves and Menezes (2022b) find significant evidence of autoregressive processes in state-level price time series, and therefore include in their regressions lags of the electricity price (dependent variable). We follow a similar approach. Coefficients $\theta_{hh,t}$, with $t = 1, \dots, 6$, are associated with the observed price in half-hour hh in the previous week. As explained above, we also include in the regression 3 lags (for the previous 3 days) of the observed electricity production in half-hour hh.

Following Gonçalves and Menezes (2022b), we do not report or analyze directly the estimated coefficients of Eq. (1). Because of the presumed autoregressive nature of prices, the estimated coefficients are often called short-run effects and provide only an estimate of the immediate effect on prices of a unit change in the associated explanatory variable. The overall effect—including the effect on prices in subsequent days—is captured by long-run effects. For a non-lagged explanatory variable i in Eq. (1), this is given by $\beta^i/(1-\sum_{t=1}^{6}\theta_{hh,t})$.[22]

In addition to estimating the effect of the carbon tax on prices, we estimate its effect on each type of electricity generation. We estimate an equation that is similar to Eq. (1), but in which the dependent variable is ET (energy type), with $ET = (blackcoal, browncoal, naturalgas, hydro, wind)$ representing the production (in MWh) of each type of generation in half-hour hh in state s:

$$\begin{aligned} ET_{hh,s} =& \beta_{hh}^{before}.Before + \beta_{hh}^{after}.After + \alpha_{hh,s} + \\ &+ \beta_{hh}^{ngas}.NaturalGas_{hh} + \beta_{hh}^{wind\_curtail}.Wind\_Curtail_y + \\ &+ \beta_{hh}^{rainNSW}.RainNSW_d + \beta_{hh}^{rainNSW}.RainTAS_d + \\ &+ \beta_{hh}^{month}.Month + \beta_{hh}^{month\{2}.(Month)^2 + \\ &+ \sum_{t=1}^{6}\theta_{hh,t}.P_{hh-t,s} + \gamma_{hh}.\mathbf{X}_{hh,s} + \varepsilon_{hh,s} \end{aligned} \tag{2}$$

This allows us to quantify the impact of the carbon tax on the quantities produced of each energy type and, therefore, understand possible substitution patterns in generation induced by the carbon tax.

6. The impact of the carbon tax

Fig. 3 shows that wholesale prices throughout the day were lower in the 'before carbon tax' period (top panel) as well as in the 'after carbon tax' period (bottom panel) compared to the carbon tax period. The figure displays the estimated coefficients of β_{hh}^{before} and β_{hh}^{after} in Eq. (1), and shows how (assuming all else constant) prices differed in the 'before carbon tax' and 'after carbon tax' periods when compared with the 'carbon tax' period. As such, in this figure (as in subsequent figures), the impact during the carbon tax period is obtained by reversing the sign of the estimated coefficients displayed therein.

Looking at the top panel—that is, in comparison with the 'before carbon tax' period—such price increases were more visible during afternoon peak hours (15h30-17 h). By contrast, in comparison with the 'after carbon tax' period, price changes were less pronounced precisely during those half-hourly slots; this may suggest a shift in the within-day pattern of electricity usage. Considering only the coefficients that are statistically significant at the 10% level, the carbon tax appears to have increased (on average) electricity prices in each half-hourly slot by \$26.3 compared with the 'before carbon tax' period (all 48 coefficients are statistically significant) and by \$34.1 compared with the 'after carbon tax' period (40/48 statistically significant coefficients). The price effect of the carbon tax appears to be close to symmetric compared with the periods before and after its introduction.

The carbon tax had clear impacts on the mix of energy sources used for generation. Our coefficient estimates of β_{hh}^{before} and β_{hh}^{after} for Eq. (2) suggest (in line with the pattern observed in Fig. 2) that the carbon tax induced a reduction in brown- and black-coal-based generation that was compensated for by natural gas and hydro-based generation. Fig. 4 displays our results for brown-coal generation. All 48 coefficients are statistically significant (at the 10% level) and suggest that on average, brown-coal generation during the carbon tax was reduced by 105 MWh compared with before and by 129 MWh compared with after.[23]

This reduction in black- and brown-coal-based generation was compensated for by natural gas (Fig. 5) and hydro-based generation (Fig. 6). In the case of natural gas, 47 (out of 48) coefficients are statistically significant (at the 10% level) and suggest an increase of 79 MWh (147 MWh) during the carbon tax period compared with before (after). Note that the impact of the carbon tax on natural gas generation, compared with the period after it was repealed, is much higher. This is a combination of two effects: on the one hand, repeal of the carbon tax; on the other hand, changes in the natural gas sector that occurred post-2014—namely, the sharp growth of Liquefied Natural Gas (LNG) production directed to export markets.[24] As Simshauser (2019a) explains, the redirection on natural gas to the LNG export market led to a scarcity of natural gas in the domestic market. In addition, the mothballing events of combined-cycle gas turbine (CCGT) plants described by Simshauser (2019a) that occurred in 2014 and 2015 contributed to a reduction in gas-fired generation that does not appear to be connected with the end of the carbon tax.

Interestingly, the substitution of brown-coal generation by natural gas was (significantly) more visible during the night (see Figs. 4 and 5). This could be due to several factors. On the one hand, the need to replace brown-coal generation with an alternative that is designed to operate continuously throughout the day. On the other hand, electricity prices at night are lower (see Fig. 1) and this could also explain the economic rationale for the observed substitution effect.

In the case of hydro generation, all 48 coefficients are statistically significant (at the 10% level) and suggest that the carbon tax induced an (average) increase of 120 MWh (40 MWh) compared with the period before (after). This change does not appear to have been uniform during the day. Compared with the period before, hydro generation increased substantially more during the day (especially during the afternoon peak hours) than during the night. Compared with the period after, however, this pattern is less visible and, in fact, is suggestive of a largely uniform change across half-hourly slots. Introduction of the carbon tax led to a significant increase in hydro production that, after it was repealed, was only partially offset. This is not immediately visible in Fig. 2 (which suggests a return to the before carbon tax weight of hydro generation), because other explanatory factors are not accounted for.

The difference in hydroelectric power generation before and after implementation of the carbon tax can be attributed to various factors. To start, favorable rainfall conditions (Australian Energy Regulator, 2013) significantly contributed to this increase. Also, leading up to the introduction of the carbon price, larger hydroelectric power suppliers strategically adjusted their market approaches (Hydro Tasmania, 2013). As a response to the carbon price legislation in late 2011, some hydro producers opted to conserve water until July 2012. This deliberate strategy allowed them to sell electricity at higher prices (Hydro Tasmania 2013, p. 22).[25]

[22] For the lagged explanatory variable—total electricity generation—the long-run effect is given by $\left(\sum_{t=0}^{3}\gamma_{hh,t}^{TG}\right)/(1-\sum_{t=1}^{6}\theta_{hh,t})$, where $\gamma_{hh,0}^{TG}$ is the coefficient of the original variable (electricity generation in half-hour hh) and $t = 1, \dots, 3$ represents electricity generation in the same half-hour hh in the previous t days.

[23] The respective results for black-coal generation (which we chose not to display in a graph) are a reduction of 118 MWh compared with before and 133 MWh compared with after.

[24] We thank a referee for this insight.

[25] For a discussion of the initial response of hydro generation to the carbon tax, see O'Gorman and Jozo (2014).

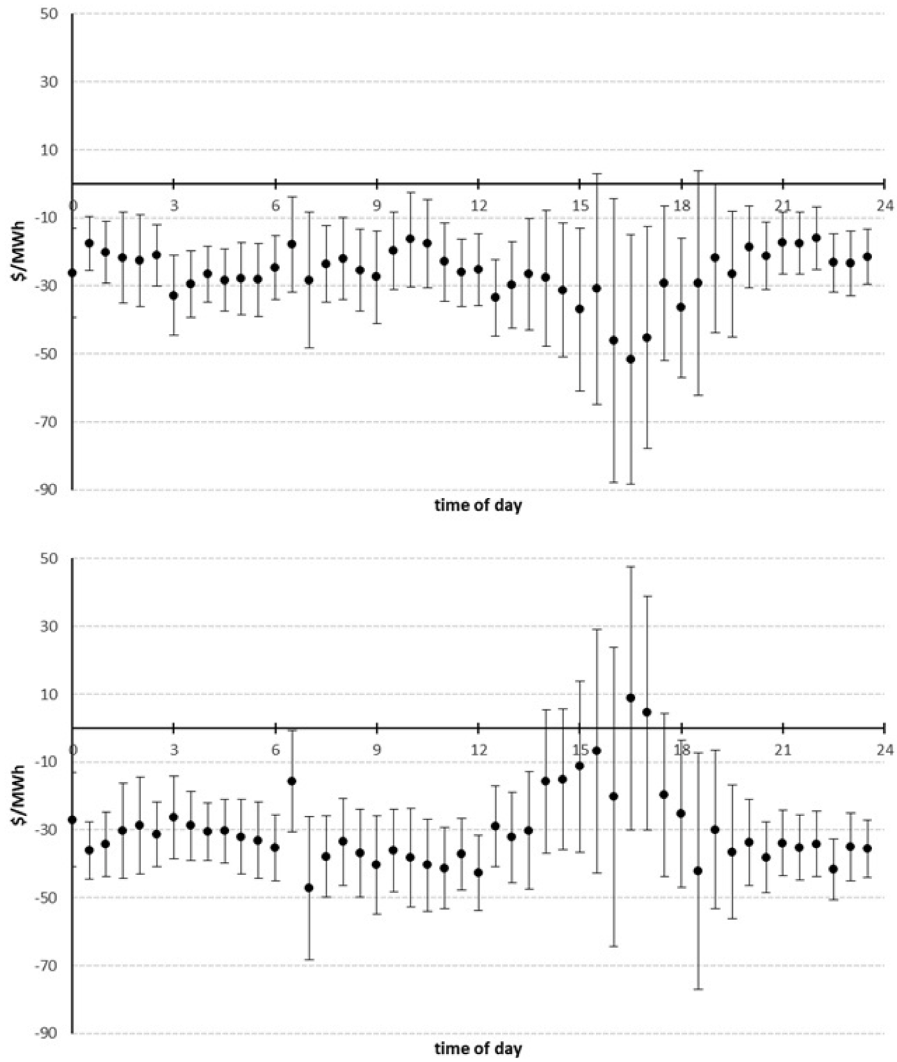

Fig. 3. Price impact of the carbon tax, by half-hourly slots: estimates of β_{hh}^{before} (top) and β_{hh}^{after} (bottom) from Eq. (1).

However, it is crucial to note that hydro generation is heavily influenced by weather patterns, which largely determine its output. While plant managers can make adjustments in production between financial years in response to a carbon tax or to create tradeable renewable certificates, hydro storage capacity is limited and fixed over time. This means that despite strategic planning, the primary driver of hydroelectric power generation is tied to weather conditions and, in our empirical approach, we have accounted for water availability, proxied by rainfall.

The results for wind (which we chose not to display in a graph) are intriguing. Throughout the period under analysis, the weight of wind generation increased steadily, although it remained relatively low in absolute terms. But even accounting for this (possibly nonlinear) trend, our results suggest that the carbon tax slowed wind penetration. On average, the carbon tax appears to have reduced wind generation by 22 MWh (20 MWh) compared with the period before (after) its implementation. One possible explanation is the curtailment of wind generation during that period. Although we do incorporate this in our regression (see Eqs. (1) and (2)), we do so in an imperfect way, by using average wind curtailment (as a percentage of total wind generation) on a state-by-state basis for the whole year (obtained from Srianandarajah et al., 2022). It could be that a 'finer' wind curtailment variable—e.g., on a daily or monthly basis—could shed further light on this puzzling result.

Finally, we have used the coefficient estimates from Eq. (2) to assess whether our model predictions are, on average, accurate. With that goal in mind, we have used the estimated coefficients for Eq. (2) and the observed values of our explanatory variables to predict the average half-hourly production (in MWh) of each energy source. This was done for the three periods we are analyzing —before, during, and after the carbon tax —in Table 1 and these predictions were compared with observed production. It appears that our model's predictive power within our sample is good.

Broadly speaking, our results suggest that if the carbon tax had not been repealed, natural gas and hydro generation would have played a more prominent role in electricity generation at the expense of coal-based generation, and likely resulted in a very different electricity-generating-capacity mix leading up to the 2022 crisis. We reach this conclusion in the following way. We have used our coefficient estimates to understand what would have happened to the quantity generated from each energy type had the carbon tax not been repealed in 2014 (which we refer to as the 'hypothetical scenario'). The results, presented in the last line of each energy type in Table 1, suggest that black- and brown-coal generation would have been 4% and 12% lower, respectively, while natural gas and hydro generation would have been 28% and 20% higher, respectively. These results highlight the pronounced shift in the energy mix, as suggested by our results, that would have been observed had the carbon tax not been repealed.

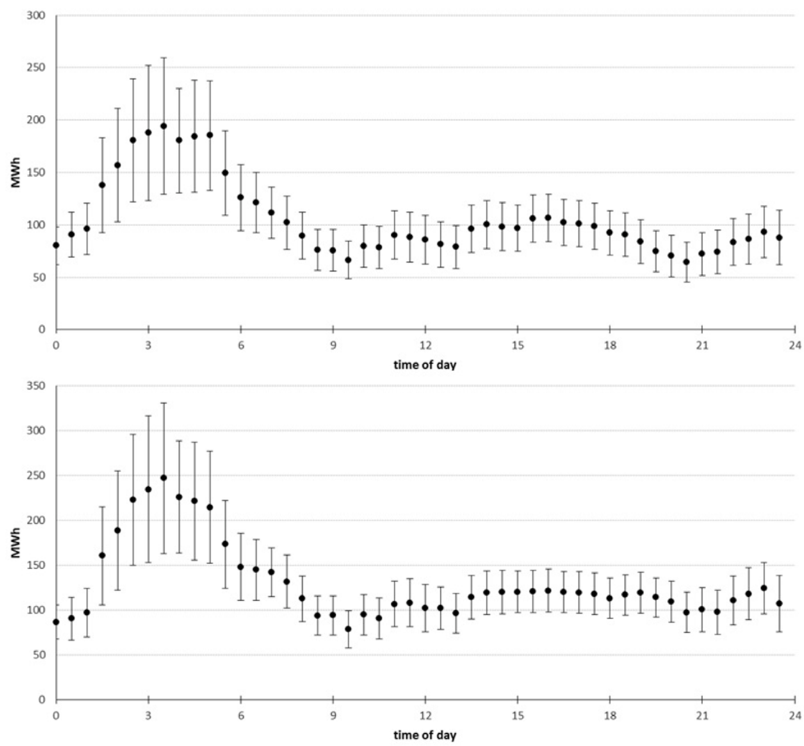

Fig. 4. Impact of the carbon tax on brown-coal-based generation, by half-hourly slots: estimates of β_{hh}^{before} (top) and β_{hh}^{after} (bottom) from Eq. (2).

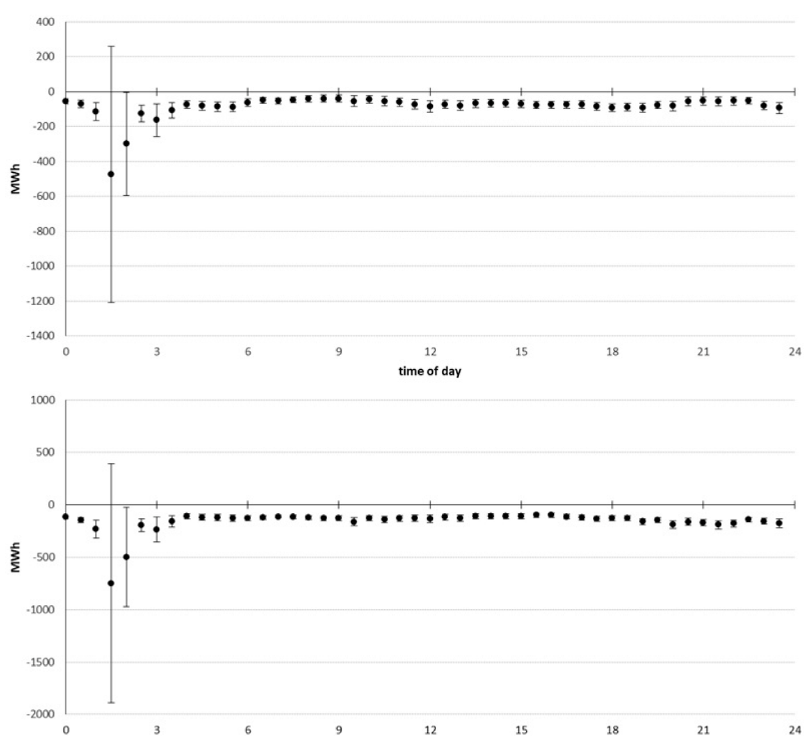

Fig. 5. Impact of the carbon tax on natural gas generation, by half-hourly slots: estimates of β_{hh}^{before} (top) and β_{hh}^{after} (bottom) from Eq. (2).

7. Discussion

This study presents econometric estimates evaluating the impact of Australia's carbon tax within the National Electricity Market. The tax was in effect from 2012 to 2014. Our findings indicate that the carbon tax effectively fulfilled its intended objectives by encouraging a shift to cleaner sources within the energy mix. We also observed symmetrical price behavior, which suggests that prices reverted to pre-carbon tax levels when considering other influencing factors. This implies that the market operated as intended, which likely rendered the decision to abolish the carbon tax a costly policy mistake—especially in light of the energy crisis experienced in 2022.

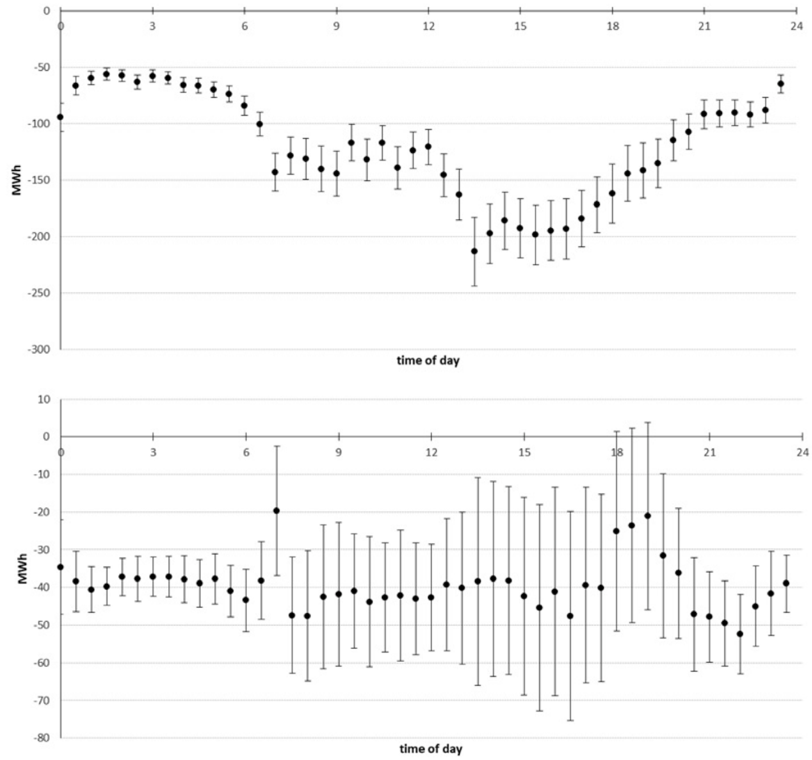

Fig. 6. Impact of the carbon tax on hydro generation, by half-hourly slots: estimates of β_{hh}^{before} (top) and β_{hh}^{after} (bottom) from Eq. (2).

Table 1
Model predictions for each type of energy generation within sample (before, during, and after the carbon tax).

Energy type	Average (daily) half-hourly production (MW)	Before carbon tax (2010–12)	During carbon tax (2012–14)	After carbon tax (2014–16)
Blackcoal	Observed	11 827	11 102	11 467
	Predicted	11 716	11 102	11 467
	Predicted in hypothetical scenario	n/a	n/a	11 043
	Percentage change between hypothetical scenario and prediction	n/a	n/a	−4%
Browncoal	Observed	6 285	5 421	5 691
	Predicted	6 229	5 421	5 691
	Predicted in hypothetical scenario	n/a	n/a	5 015
	Percentage change between hypothetical scenario and prediction	n/a	n/a	−12%
Natural gas	Observed	2 072	2 223	1 675
	Predicted	2 053	2 223	1 675
	Predicted in hypothetical scenario	n/a	n/a	2 140
	Percentage change between hypothetical scenario and prediction	n/a	n/a	28%
Hydro	Observed	1 618	1 979	1 503
	Predicted	1 602	1 979	1 503
	Predicted in hypothetical scenario	n/a	n/a	1 811
	Percentage change between hypothetical scenario and prediction	n/a	n/a	20%
Wind	Observed	286	511	762
	Predicted	286	511	762
	Predicted in hypothetical scenario	n/a	n/a	716
	Percentage change between hypothetical scenario and prediction	n/a	n/a	−6%

Fig. 7, similarly to Fig. 2, displays the average weight of each of the main types of electricity production in each half-hour (including solar generation) during the carbon tax period and for a longer time period (until October 2020) after the carbon tax. In comparison with Fig. 2, we can see that brown coal's weight in total generation decreased, whereas the weights of natural gas, hydro (both especially in the evening, around 20 h), wind, and solar generation increased. It is also clear from Fig. 7 that ramping up black coal at peak became more prominent post-carbon tax, which contributed to the deterioration of the economics of coal-fired power generation in the NEM.

Had the carbon tax been sustained, the economic feasibility of gas would have improved. Conversely, the economics of coal-fired power would have deteriorated earlier, preceding the rise of solar generation from mid-2018, as highlighted by Gonçalves and Menezes (2022a).

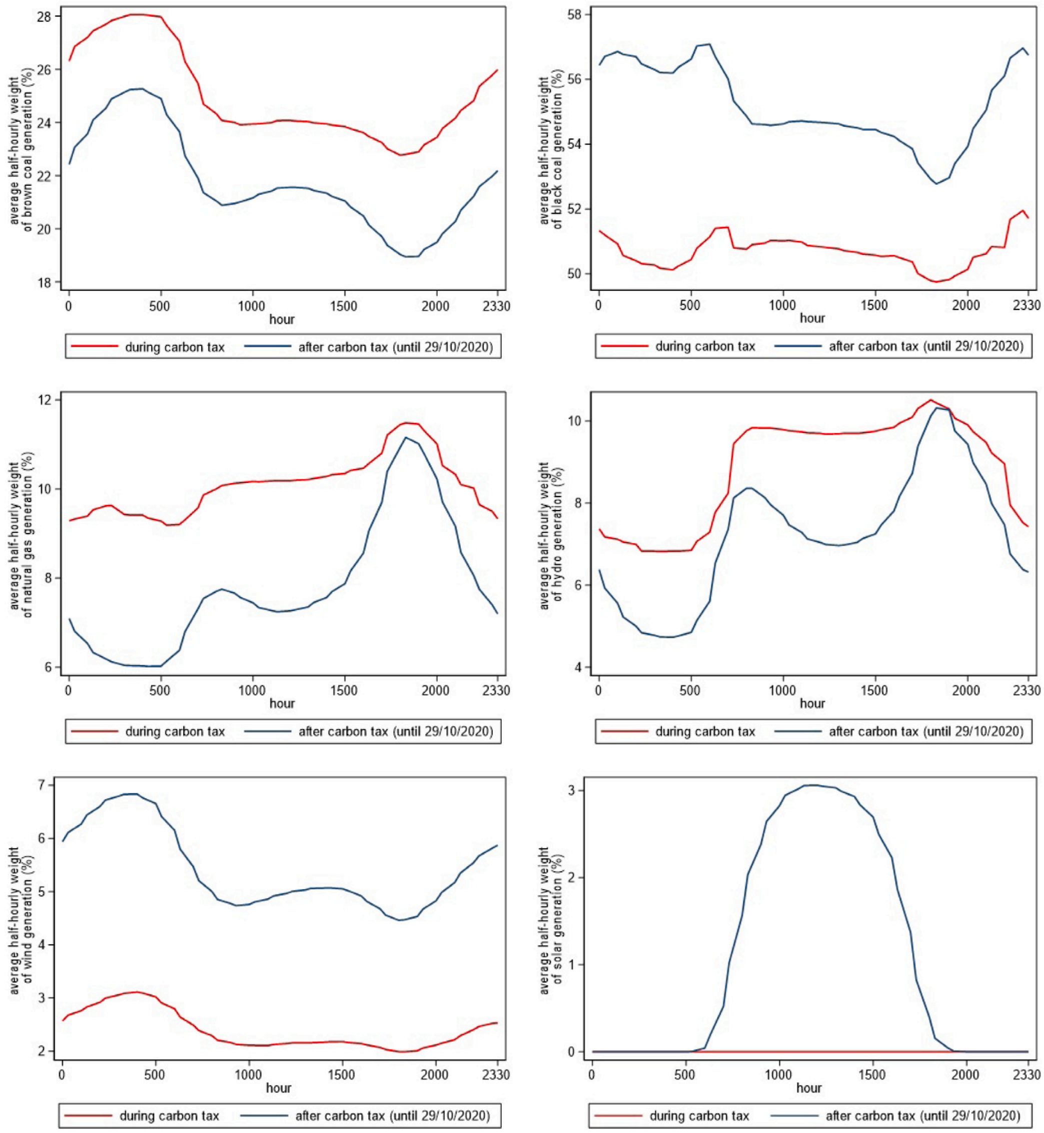

Fig. 7. Weight of each type of electricity production, during and after the carbon tax (until 29/10/2020), by half-hourly slots.

Hence, its continuation might have facilitated a more organized phasing out of aging coal-fired power plants, and potentially mitigated the unplanned unavailability that partly contributed to the 2022 crisis.

We also believe that retaining the tax package could have facilitated the construction of additional gas-generation facilities. This could have signaled a surge in domestic demand for natural gas, and potentially boosted gas exploration, production, and transport infrastructure development. Furthermore, it might have incentivized long-term contracts, and thus provided some protection to gas generators from the international gas price volatility observed after major LNG projects' completion from 2015 onward.

In essence, had the carbon tax package not been repealed, the energy mix preceding the 2022 crisis would likely have featured a higher gas share and a lower coal share. However, it remains unclear whether this shift would have prevented or alleviated the crisis. This uncertainty is tied to how the domestic gas industry would have evolved with the tax and the identification of market design flaws. These flaws led generators to declare themselves unavailable when their costs exceeded the price cap due to high fuel prices.

Importantly, though, the repeal of the carbon tax package did not impede the energy transition. Yet the increased adoption of renewables primarily stemmed from mechanisms outside the market. As a consequence, market prices no longer effectively signal the need for investment in generation.

In this paper, we encourage readers to contemplate an alternative past in which market forces could have guided a smoother energy transition and enabled a more significant role for gas generation, faster emission reductions, and economically favorable conditions for investing in storage, including hydro.

CRediT authorship contribution statement

Ricardo Gonçalves: Writing – review & editing, Writing – original draft, Validation, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Flávio Menezes:** Writing – review & editing, Writing – original draft, Validation, Methodology, Investigation, Formal analysis, Data curation, Conceptualization.

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