Tax Induced Emissions? Estimating short-run emission impacts from carbon taxation under different electricity market structures

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Tax Induced Emissions? Estimating short-run emission impacts from carbon taxation under different electricity market structures

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Abstract

This paper evaluates the relevance of market structure on the short-run effectiveness of carbon taxation by utilizing the introduction of Australia’s carbon tax in 2012, its removal in 2014, and between these dates a change in market structure in Western Australia where the dominant generator became vertically integrated with the market retailer. The market power of the dominant firm decreased with the introduction of the carbon tax, reducing its profit incentive to lower its coal based generation in some demand conditions and increasing equilibrium carbon emissions. However, when vertically integrated, the dominant firm behaved more competitively and the carbon tax reduced equilibrium carbon emissions. The results indicate that the immediate short-run impacts from carbon taxation can be small and perhaps even induce emissions in imperfect markets. However, these short-run results have limited long-run implications because it is expected that a carbon price would result in incentives for electricity generators to invest in a less emissions-intensive capital stock. Rather, these short-run findings highlight the importance for an emissions tax to cover a broad base of industries and be long lasting in order to achieve substantive reductions in carbon emissions.

1 Introduction

Many countries tax externalities in an attempt to improve the welfare of their citizens, a policy directed by economic theory when assuming perfectly competitive markets. However, as first described by Buchanan (1969), taxing an externality when markets that are not perfectly competitive is not unambiguously welfare increasing. Therefore, the form of the market imperfection, or the market structure, will influence the impact a corrective tax will have on equilibrium outcomes. Despite the obvious investment incentives a long term carbon emissions tax

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will provide, a developing literature is forecasting modest short-run emissions responses to carbon taxation when controlling for no changes in electric generating technology. The purpose of this paper is to empirically assess the short-run impact an actual carbon tax had on emissions from the electricity sector in Western Australia, and how this impact differed under two different market structure regimes.

The Australian Government introduced a carbon pricing scheme on July 1 2012. The scheme was planned to have two phases. The first phase, from 2012-2015 was to have emitting firms surrender emissions permits to cover their emissions, which could be purchased for a fixed price of $23 (AUD) per metric ton of carbon dioxide in 2012/13, and for $24.15 in 2013/2014. This was in effect a tax, and was designed as a temporary phase-in period for a cap-and-trade system that was to be introduced from July 1 2015. However, following a change of Government, the transition to a cap-and-trade never occurred, with the policy changed such that emissions were no longer subject to taxation or permit requirements from July 1 2014. In this paper, I utilize the unique features of the wholesale electricity market in Western Australia to evaluate the impacts of this, hereby denoted, “carbon tax” on emission levels, market power and prices. I demonstrate that in markets with imperfect competition, the theoretical short-run impact of the tax is ambiguous. Depending on the costs, emission rates and ownership assignment of electricity generators, carbon taxation could decrease, increase or have no effect on emissions for a fixed level of demand. I then document empirical evidence from the Western Australian wholesale electricity market that shows the introduction of a carbon tax increased emissions by encouraging a different generator production mix. I provide further evidence that this counter-intuitive response to the tax is due to the flattening effect the tax had on the aggregate market marginal cost function, making it less profitable for the dominant player in the market to exercise unilateral market power by reducing its coal generation. However, when the dominant firm’s incentive to exercise unilateral market power dampened after becoming vertically integrated with the market retailer, the tax appears to have slightly reduced carbon emissions. A descriptive counterfactual exercise shows that the observed emissions reduction was similar in magnitude to the level expected if the market was perfectly competitive. Although long-run investment responses to a carbon tax should result in lower emission capital stock, if policy makers seek a short-run reduction in carbon emissions, the policy implication of this result is that the size of the tax must be chosen carefully or that sectors covered by the tax should extend beyond electricity markets.

This paper adopts the Robinson (1988) estimator to examine the changes resulting from the introduction and removal of the carbon tax. The model and results add to the body of work on carbon taxation and competitive behavior in electricity markets. First, in two recent papers, researchers have investigated how lowering gas prices (relative to coal) has affected carbon emissions from electricity generation. Cullen and Mansur (2014) use the price variation provided by the shale gas boom in the USA to forecast the impact various carbon taxes would have on carbon emissions from electricity generation, holding demand and generating technologies fixed. Knittel, Metaxoglou, and Trindade (2015) examine the heterogeneity in regional carbon emissions reductions from electricity generation over the shale gas boom. Respectively, the authors of the two papers find that the emissions reductions from a carbon tax are likely to be quite small in the short-run, and that generation in restructured electricity markets were substan-
tially less responsive to the shale boom than traditionally structured markets. The analysis in this paper provides a plausible economic explanation for the findings in these recent papers by analyzing the immediate, short-run impact an actual carbon tax had on market power and carbon emissions in the Western Australian wholesale electricity market. By also focusing on short-run outcomes, the analysis emphasizes that even if the cost-ordering of generators is to change with a carbon tax or the shale boom, imperfect markets may alter their production mix in a different manner than state-owned or regulated monopolies. In particular, being able to compare the impact of the carbon tax in the same market under two separate market structures allows a unique opportunity to examine the interaction of market structure and carbon taxation. Together, the results in this paper, Cullen and Mansur (2014) and Knittel, Metaxoglou, and Trindade (2015) suggest that for electricity generation, the majority of emission reductions from carbon taxation are likely to come from long-run investment responses, rather than substantial short-run fuel substitution responses. However, this result relies on no short-run investment or shut down responses from the generating sector. In a comprehensive evaluation of emissions from Australia’s largest electricity market,1 O’Gorman and Jotzo (2014) show that emissions were substantively lower in the short-run following the introduction of the carbon tax, in large part due to 4GW of brown and black coal generating capacity being taken offline as an immediate response to the tax.

Further, this paper adds to the literature in environmental economics of evaluating carbon taxation in imperfect markets. Fowlie, Reguant, and Ryan (2015) show that carbon taxation in monopolistic industries can increase welfare loss as the lower production levels by the monopolist somewhat corrects the emissions externality, with further taxation proving distortionary, rather than corrective. Kolstad and Wolak (2013) provide evidence consistent with generating firms in Los Angeles using NOx permit markets to drive up the costs of marginal generators, increasing equilibrium electricity prices. Here, I show that taxation can potentially alter equilibrium production allocation toward higher emitting generators, making welfare impacts ambiguous. Finally, I add to the weight of papers describing how profit maximizing strategies for electricity generator owners can change with non-linearly with costs by analyzing the impact the carbon tax had on generation costs and market equilibrium outcomes. Evidence from Borenstein, Bushnell, and Wolak (2002) showed that wholesale price increases in California from 1998-2000 were not only due to cost passthrough but to changes in the levels of market power exercised by the generators and evidence from Fabra and Reguant (2014) show that generators fully internalize emissions costs in their strategies.

The paper proceeds with a stylized model of an electricity generating market to establish the theoretical expectation that without information on generators and ownership characteristics, emissions may rise or fall following the introduction of carbon emissions taxation. Then, I briefly describe the Western Australian wholesale electricity market and the emissions tax details, outlining some predictions for the impact of the carbon tax in Western Australia. The data and empirical strategy for identifying the impact the carbon tax had on emissions, mar-

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1Australia’s National Electricity market (the NEM) was subject to the same carbon emissions regime as Western Australia described in this paper. The NEM services the majority of the population of Australia, extending across Queensland, New South Wales, Victoria, South Australia and Tasmania.
ket power and prices are then outlined and the results are presented before some concluding remarks relating to the implications of the results for policy makers.

2 Stylized model

To illustrate the possible changes to an electricity market equilibrium following the introduction of a carbon tax, this section graphically presents a simple one-stage market environment, where one participant has market power. Electricity markets are often concentrated, and the Western Australia setting used in the empirical section has one firm, Synergy, owning over half of the generating capacity in that market. We will observe that, for a given level of inelastic demand, equilibrium emissions can increase, decrease or not change following the introduction of a carbon tax, depending on the characteristics of the market participants.

Electricity is a non-storable good, it must be consumed as it is generated. Therefore, conditional on a fixed level of demand, it is only possible for emissions to be altered by a tax if the equilibrium production mix can change, so demand must be sufficiently smaller than capacity. Consider a market that consists of a participant with market power that owns a mix of coal and gas electricity generators, and a group of non-strategic firms that own a variety of coal and gas generators and supply at marginal cost. Generators may vary in marginal cost and emission levels. Assume demand is inelastic at some level $D$. The strategic firm therefore is a monopolist over a downward slopping residual demand curve\(^2\) and will maximize profits by generating a quantity where marginal revenue equals marginal cost. Without further details regarding the marginal costs and emission factors of the generating portfolios, it is uncertain as to whether the introduction of a carbon tax will result in more or less production for the strategic firm. Figures 1a and 1b display a case where the firm faces a steeper residual demand curve and marginal cost curve after the introduction of the tax, resulting in a reduction in its optimal level of output. Given demand is fixed at $D$, this means other firms will increase their combined output. Conversely, figures 1c and 1d displays the firm facing a flatter residual demand curve and having flatter marginal costs, thus increasing its optimal output.

The impact of the strategic firm altering its output on market emission levels will depend on the emission intensities of the generators it and the other firms own. If the strategic firm alters its production level, then an equal magnitude change in production is required by other generators to meet market demand $D$. Therefore, the emissions impact of the tax will depend on the emissions intensity of the generators that change output levels. For example, figure 2a illustrates that if the strategic firm owns emission intensive coal generators while the rest of the market owns less emission intensive gas generators, then for a fixed level of demand, $D$, a reduction in the strategic firm's output would reduce emissions. However, figure 2b shows that if the strategic firm owned the gas generators and the rest of the market owned coal generators, then a reduction in the strategic firm's output would increase emissions for a fixed level of demand. Figure 2c presents a more realistic case where all firms own a mixture of coal and gas generators, with coal being the cheaper generation source. Here, emissions are highest at intermediate levels of the strategic firm's production, where all market generation is from coal.

\(^2\)The residual demand curve plots the amount of generation the strategic firm would produce for a given price it is willing to supply electricity at.
Figure 1: Effect of the Carbon Tax on Market Equilibrium

(a) Case 1. No tax baseline equilibrium where strategic firm decreases production

(b) Case 1. With tax equilibrium where strategic firm decreases production

(c) Case 2. No tax baseline equilibrium where strategic firm increases production

(d) Case 2. With tax equilibrium where strategic firm increases production

\( P_{NT} \) and \( Q_{NT} \) denote no tax equilibrium price and strategic firm quantity. Other firms quantity is \( D - Q_{NT} \). \( P_T \) and \( Q_T \) denote the taxed equilibrium price and strategic firm quantity. Other firms equilibrium quantity is \( D - Q_T \).
From this point, a deviation to higher strategic firm generation results in substituting other firm coal generation with strategic firm gas. A lower strategic firm generation would substitute their coal generation for other firm gas generation. Finally, figure 2d presents a case where all firms own a mixture of coal and gas generators, with gas being the cheaper generation source. Here, emissions are lowest at intermediate levels of the strategic firm's production, where all market generation is from gas. Therefore, a switching of the cost merit order of coal and gas should result in the function changing from the inverted-V shape seen in figure 2c to V-shaped, as in figure 2d.

To summarize, without imposing institutional detail on the problem we cannot predict the taxation impact on:

1. Strategic firm generation.
   - Generator characteristics, ownership allocation and size of tax will determine how the tax will change the slope of the firm's residual demand and marginal cost curve.

2. The cost advantage of coal generation over gas generation.
   - Emission intensities of the generators and the size of the tax will determine whether coal plants become more expensive than gas plants to generate electricity.

3. The impact the tax will have on overall market emissions.
   - Depends on (1) and (2) and the distribution of demand levels ($D$) observed in the market.
Figure 2: Market-wide carbon emissions as a function of strategic firm output, given fixed demand $D$

(a) Case 1. Strategic firm owns coal generators, other firms own gas generators

(b) Case 2. Strategic firm owns gas generators, other firms own coal generators

(c) Case 3. Firms own mixture of coal and gas generators with coal cheaper to operate

(d) Case 4. Firms own mixture of coal and gas generators with gas cheaper to operate

Figure assumes a fixed demand of $D$ MW. Market-wide emissions function assumes that $D$ MW of electricity is generated, with the strategic firm generating $x$ MW using its cheapest generators and other firms generating $(D - x)$ MW using their cheapest generators.
3 The Western Australian electricity market and the impact of the carbon tax on marginal costs

The Western Australian Wholesale Electricity Market (WEM) operates 48 half-hour markets a day. The Independent Market Operator (IMO) operates the market. In the day-ahead market, the IMO requires all generators (suppliers) and loads (consumers) to lodge any pre-existing bilateral contract arrangements and submit a discrete function representing the prices at which they are willing to increase and/or decrease their obligations from these contracted positions. The IMO then aggregates all of the offers to increase production and decrease consumption into a supply function, and aggregates all the bids to decrease production or increase consumption into a demand function. The IMO clears the market, setting a price such that supply is matched to demand. From July 1 2012 (the same time the carbon tax was introduced), the IMO began operating a real-time balancing market. Here, again market participants submit their willingness to adjust their day-ahead positions in the event that the system requires balancing if in real-time load deviates from generation. Therefore, generation strategies for half-hour time intervals of physical electricity delivery are part of a three stage game, with forward positions, day-ahead forward adjustments and real-time market strategies.

The model presented in the previous section provides a large abstraction from the WEM, however, the result that the tax may increase or decrease emissions is very relevant, given the empirical results to follow. The generation in the WEM is characterized by a dominant player - Synergy Energy - owning and operating over 50% of the generating capacity. The market does not contain hydroelectric generation and given its isolation, contains no interconnections to any other markets. The remoteness and stability in the generating stock provides a clean setting for assessing the impact of a carbon tax. Despite Synergy's dominance as a generator at both the introduction and removal of the carbon tax, the market structure greatly differed at these points in time. In 2012, the market had a monopolist retailer, that purchased electricity from the wholesale market and charged end-consumers a fixed retail price set annually by the Western Australian Government. However, on January 1 2014, Synergy's generating arm merged with the retailer to become a vertically integrated entity. Figure 3 displays in a timeline the changes in the market structure and carbon tax.

The first, descriptive impact of the carbon tax can be seen in the changes to the marginal costs of coal and gas generation, displayed in Table B1 and graphically in Figure 4. The four charts display engineering estimates of the short-run marginal cost curves and emission rates for Synergy and all other generators, with and without a carbon tax. Each flat line joining the

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3 The day ahead market operates the morning before the half-hour period in which the physical electricity is traded.

4 The quantities traded in this market are adjusted for transmission losses.

5 Before 2012, this market function was provided by Synergy as a regulated monopolist.

6 No new coal or gas generating capacity was added between the sample window of 2011-2015, and the descriptive statistics will show that wind generation remained largely constant.

7 Before the vertical integration, the generating arm was owned by Verve Energy. Throughout this paper, references to Synergy are intended to refer to the dominant generating firm.

8 201MW of peaking, distillate fueled generators are omitted from the table and charts. They are high cost, high emissions plants used very infrequently.
dots represents the capacity and marginal cost of a generator and the cumulative order is from
the lowest to highest marginal cost. We observe that Synergy has one minor change in the
marginal cost rankings from the tax, being the cheapest generator. However, the major impact
of the tax appears to be a flattening of the curve between 1000-1500MW. This flattening still has
the higher emitting power plants just cheaper than the lower emitting plants. As for the rest of
the market, the cheap and emissions heavy MUJA_G1-MUJA_G4 coal generating units move to
being slightly more expensive than the ALINTA_PNJ_U1 cogeneration gas unit, contributing to
a large flattening of the marginal cost curve between 500-1000MW of cumulative capacity.

Relating the marginal cost changes resulting from the carbon tax with the stylized model
in the previous section, after the introduction of the carbon tax Synergy potentially faced a less
steep residual demand curve for quantities up to 1500MW. This is seen in Figure 5 that illustrates
Synergy’s residual demand curve for an inelastic 2000MW demand and competitors supplying
at marginal cost. This may imply that Synergy had more ability to exercise unilateral market
power before the introduction of the tax. Figure 5 also displays the market-wide carbon emis-
sions on the right axis for 2000MW of demand as a function of Synergy’s generation, assuming
lowest cost dispatch by Synergy and its competitors. The variation in these market emission
levels reflect substitution of generation between Synergy and non-Synergy plants with different
emission levels. The sensitivity of emissions to the generation mix is stark - at peak emissions
where Synergy generates 1231MW of the 2000MW, 914 tons of carbon dioxide equivalents are
emitted in a half hour, whereas if Synergy only generated 846MW of the 2000MW, emissions fall
11% to 821 tons. The figure also illustrates the lack of merit order shifting from coal to gas, as
the market emissions function of Synergy generation for 2000MW of market generation devi-
cates from the inverted-V shape. Therefore, for 2000MW of inelastic demand with no changes
in generator ownership or technology, the only way emissions levels would reasonably be ex-
pected to change in the market would be due to changes in the strategic firm’s optimal strategy.
That is, the tax was small enough to mostly maintain the ordinal cost rankings of the generators
in the market, so the market power impacts of the tax will be the driver of any emissions differ-
Figure 4: Engineering estimates of short-run marginal costs and emissions rates, 2014

(a) Synergy-owned generators, no carbon tax
(b) Synergy-owned generators, with carbon tax
(c) Other-owned generators, no carbon tax
(d) Other-owned generators, carbon tax
ences in the market.

Given that generating technology and ownership for the surrounding periods of the carbon tax introduction are unchanged, plus the changes in the cost curves that were just outlined, the theory outlined in section 2 predicts the following short-run impacts from a $23 carbon tax in Western Australia.

1. For fixed market generation levels near the coal/gas threshold of production:
   
   (a) Synergy should have less market power
   
   (b) Synergy generation levels should be unchanged or higher, therefore their competitors should produce less
   
   (c) Emissions changes are uncertain
   
   • Outcome depends on whether Synergy increases coal-based generation and if it substitutes other firms’ gas- or coal-based generation
   
   (d) Equilibrium prices should rise by between $12 and $27.
   
   • Relies upon strong assumptions - if passthrough is complete or non-strategic firms supply at marginal cost then prices should rise by the cost increase for the marginal unit, which is $12 for the lowest emitting unit and $27 for the highest emitting unit.

2. For fixed market generation levels less than the coal/gas threshold of production:

   (a) Synergy market power should not substantially change
   
   (b) Given the size of the tax is small and does not substantially change the order of generator marginal costs, little emission effects

The theory in the previous section may not apply for the removal of the carbon tax when Synergy was vertically integrated. Numerous studies have documented that restructured electricity markets that have some degree of vertical integration between the generation and retail arm tend to have more competitive outcomes. For example, Mansur (2007) and Bushnell, Mansur, and Saravia (2008) show that vertical integration in electricity markets can improve production efficiencies and result in more competitive market outcomes. The mechanism described in these papers is that the generating arm internalizes the retail arm's profits in their supply function decisions, resulting in less incentive to raise prices. In section 4.2.1 we will observe some basic descriptive tests that suggest that the vertically integrated market structure had more competitive behavior than the previous market structure in Western Australia. Therefore, we may expect these predictions to be less pronounced and follow that of a more competitive market where emissions fall with a tax.

These predictions will be tested in the following empirical sections. Note that these predictions are not general carbon tax predictions - rather they are 1) immediate short-run, 2) market specific and 3) tax-level specific. The predictions and empirical results are not robust to changing the context from either of these three points.
Figure 5: Synergy residual demand and market level carbon emissions as a function of Synergy generation for load of 2000MW

Figure constructed from data in Table B1, assuming fixed demand of 2000MW. Market-wide emissions function assumes that 2000MW of electricity is generated, with Synergy generating $x$MW using its cheapest generators and non-Synergy firms generating $(2000 - x)$MW using their cheapest generators.
4 Data and Measurement

This paper uses market clearing data and day-ahead market bid data for the Wholesale Electricity Market (WEM) in the South West Interconnected System (SWIS), the electricity market for Perth and the surrounding region in Western Australia. Australian generators were subject to a carbon emissions tax from July 1 2012 to June 30 2014. From January 1 2014, the generating arm of Synergy (then Verve Energy) merged with the regulated monopolist retailing arm of Synergy to form a vertically integrated firm. Recall figure 3 that displays these events and the samples used in the analysis. The empirical strategy, outlined in the next section, uses a 6 month, 1 January to 1 July window before and after the tax introduction and removal for estimating the impact of the tax. Therefore, there are 4 time windows used for comparison purposes, with sample A from figure 3 containing observations from a market with no carbon tax and no vertically integrated firm (Jan-Jul 2012), sample B containing observations from a market with a carbon tax and no vertically integrated firm (Jan-Jul 2013), sample C containing observations from a market with a carbon tax and a vertically integrated firm (Jan-Jul 2014), and finally sample D containing observations from a market with no carbon tax and a vertically integrated firm (Jan-Jul 2015). The unit of observation throughout the paper is a 30 minute market period. Each period contains output levels and outage status for each generator. Further, it contains information on the clearing prices in the day-ahead contract market and the real-time balancing market, load forecasts at 24 and 1 hours before the market runs and realized load. Throughout the empirical sections, market generation is defined as generation from dispatchable sources that participate in the wholesale market. That is, it is equal to net demand (demand minus intermittent generation from wind and solar generators).

Generator information was collected from the annual assumptions and methodology reports compiled for the IMO. These reports (Sinclair Knight Merz MMA (2014) and various issues) include estimates of generator marginal costs and emission factors (metric ton of carbon dioxide per MWh of electricity produced). For each half hour period in the data, individual generator output levels are multiplied by the emissions intensity of the generator and then aggregated to calculate the electricity market emissions for that period.

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9 The data are made available to the public by the Independent Market Operator (IMO) and can be accessed at http://data.imowa.com.au/
10 These windows are chosen given they will compare time windows that cover the same seasons. Given there was only a six month window where Synergy was vertically integrated and a carbon tax was in place, all comparison samples are similarly confined to the same calendar months for comparative purposes.
11 The footnote of table B1 explains in more the detail the construction of generator characteristics.
12 a) Some power plants can use coal, gas or distillate and actual fuel usage is unobserved. Consequently, market level output and emissions are constructed excluding the contribution from these plants. The average production from these units are less than 10MW. Results are not sensitive to including these plant and applying the average emissions rate for those plants.
b) Although this method will result in some measurement error, the distribution of individual generator quantities produced, conditional on running, does not substantively change with and without a carbon tax. Consequently I maintain the assumption that emissions from starting up plants and plant-level non-linearities in emission rates are adequately summarized by this measurement.
4.1 Constructing a market power measure

To calculate a measure of market power, I use the method outlined in McRae and Wolak (2014) to extract estimates of firm mark-ups over their costs in electricity markets. McRae and Wolak (2014) and Wolak (2015) illustrate that this measure is higher in periods where generating firms have greater market power.\(^{13}\) By considering the ex-post profit maximization problem for the generating firm, where other firm strategies and demand levels are known, the first-order condition is:

\[
P - C = -\frac{DR(P)}{DR'(P)}
\]

where \(DR(P)\) is the residual demand for the firm at price \(P\) and \(C\) is assumed to be a constant marginal cost. Defining the net inverse semi-elasticity residual demand curve as

\[\eta = -\frac{1}{100} \frac{DR(P)}{DR'(P)}\]

we get:

\[P = C + 100\eta\]

\(\eta\) gives the $/MWh increase in the market clearing price associated with a 1% reduction in output by the generating firm. Therefore, a higher value of \(\eta\) implies greater market power as the ability for the firm to raise prices is higher. Further, higher values of \(\eta\) imply less competitive pricing as the markup above costs is higher. \(\eta\) is numerically operationalized using the bidding step-functions observed in the day-ahead market in the same manner as McRae and Wolak (2014). That is, \(P_1\) and \(P_2\) are defined as the price levels of the nearest step above and below Synergy’s residual demand equilibrium quantity that lie greater than 10% away from the equilibrium price, with \(Q_1\) and \(Q_2\) the corresponding residual demand for Synergy at these prices. Then,

\[
DR'(P^*) \approx \frac{DR(P_1) - DR(P_2)}{P_1 - P_2} = \frac{Q_1 - Q_2}{P_1 - P_2}
\]

\[
\eta = -\frac{1}{100} \frac{DR(P^*)}{DR'(P^*)}
\]

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\[
DR'(P^*) \approx \frac{DR(P_1) - DR(P_2)}{P_1 - P_2} = \frac{Q_1 - Q_2}{P_1 - P_2}
\]

\[
\eta = -\frac{1}{100} \frac{DR(P^*)}{DR'(P^*)}
\]

Where \(Q^*\) is the observed output for Synergy in the given half hour and \(P^*\) is the equilibrium price in that half hour.

4.2 Summary statistics

4.2.1 Changes in competition measures from Synergy becoming vertically integrated

Work by Mansur (2007) and Bushnell, Mansur, and Saravia (2008) that assesses the impact of vertical integration on market outcomes provide evidence that wholesale market participants

\(^{13}\)For example, in Wolak (2015), it is shown that for delivery hours where there are transmission constraints which grant higher market power to generators given the lower competition, this measurement was much higher than in the no constraint counterfactual.
can behave more competitively when some market participants are vertically integrated. The following comparisons are made to test for firms behaving more competitively after the vertical integration of Synergy. The tests compare the mean value for each half-hour period in Jan 1 2013 - Jul 1 2013 (no vertical integration, sample B in figure 3) to Jan 1 2014 - Jul 1 2014 (vertical integration, sample C in figure 3) with a size of 5%.

1. Alternate hypothesis: Synergy’s ability to increase prices ($\eta$ from equation 4) decreases.
   
   \[ H_0 : \mu_{\eta, VI} = \mu_{\eta, No VI} \]
   \[ H_1 : \mu_{\eta, VI} < \mu_{\eta, No VI} \]
   \[ \mu_{\eta, No VI} = 5.45, \mu_{\eta, VI} = 4.06, \text{reject null with p-value of 0.0494}. \]

2. Alternate hypothesis: Bilateral contract coverage ($CC = \frac{\text{total bilateral contracts}}{\text{market generation}}$) increases. This implies that there are less days where the generators are in a short position, so they have less incentive and opportunity to exercise market power.

   \[ H_0 : \mu_{CC, VI} = \mu_{CC, No VI} \]
   \[ H_1 : \mu_{CC, VI} < \mu_{CC, No VI} \]
   \[ \mu_{CC, No VI} = 0.9711, \mu_{CC, VI} = 1.007, \text{reject null with p-value of less than 0.0001}. \]

3. Alternate hypothesis: Cost inefficiency ($CI = \frac{\text{total generating cost}}{\text{minimum possible generating cost}}$) decreases.\(^{14}\)

   \[ H_0 : \mu_{CI, VI} = \mu_{CI, No VI} \]
   \[ H_1 : \mu_{CI, VI} < \mu_{CI, No VI} \]
   \[ \mu_{CI, No VI} = 1.306, \mu_{CI, VI} = 1.283, \text{reject null with p-value of less than 0.0001}. \]

Although these tests are descriptive in nature, they provide a basis to conclude that the market structure was different when the tax was introduced to when it was removed and market participants behaved differently. Therefore the analysis in this paper will compare the differences in market outcomes with and without a carbon tax in the Western Australian market separately under the two market structures. Differences in the estimated impacts of a carbon tax under the different market organization can be informed by the previous literature on vertical integration in restructured electricity markets and the descriptive evidence above that, on average, firms behaved more competitively when there was a vertically integrated firm in the market.

4.2.2 Differences in market outcomes measures with and without a carbon tax

Descriptive plots of market generation, market emissions, Synergy generation and market prices are found in figure A1. These figures display the average level for the given variable for each day in the sample window. We observe strong seasonality in market generation, with a high Summer peak and a moderate Winter peak, with lowest consumption in Autumn and Spring. As expected, there is a positive relationship between market generation, market emissions and Synergy generation. However, there are only obvious level changes in equilibrium

\(^{14}\)Total generating cost assumes that the average cost of generation is the engineering estimate of marginal costs in table B1. Start up costs are not included in this estimate. Minimum possible generating cost is the counterfactual total generating cost if the available online generators produced strictly in order of marginal cost until the level of market generation observed.
prices and perhaps Synergy generation at the date thresholds of the carbon tax introduction and removal.

Table 1 displays descriptive statistics at a half-hour unit of observation for the WEM, for the January 1 - July 1 time window either side of the introduction of the carbon tax. We observe that the mean of emissions and emission intesity were higher in the period with a carbon tax. A comparison of means test between the taxed and untaxed sample results in all outcome variables of interest (Emissions, Emissions per 1000MWh, Synergy generation, Synergy inverse semi-elasticity and prices) being statistically different at a 5% level of significance. We see similar patterns in table 2, for the removal of the carbon tax when the market had a vertically integrated generator/retailer, although the increase in emissions and reduction in market power are less pronounced. However, plant outages are also statistically different across each sample, meaning that the emissions consequences could be driven by outage planning. The empirical strategy for estimating the impact of the tax will seek to adequately control for generator outages and total generation for the short-run impact of the tax to be estimated.

Table 1: No vertical integration: Western Australian wholesale electricity market statistics for the January-July before and after the removal of the carbon tax, 2012

<table>
<thead>
<tr>
<th>Variable</th>
<th>N</th>
<th>Mean (sd) tax</th>
<th>Mean (sd) no tax</th>
<th>Mean diff. tax - no tax</th>
<th>t-stat</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Generation (MW)</td>
<td>8736</td>
<td>1891.22 (412.05)</td>
<td>1881.42 (444.10)</td>
<td>9.80</td>
<td>1.51</td>
</tr>
<tr>
<td>Emissions (Tons)</td>
<td>8736</td>
<td>743.43 (156.01)</td>
<td>711.95 (157.36)</td>
<td>31.47</td>
<td>13.26</td>
</tr>
<tr>
<td>Emissions per 1000MWh</td>
<td>8736</td>
<td>393.65 (13.64)</td>
<td>379.74 (12.88)</td>
<td>13.91</td>
<td>69.24</td>
</tr>
<tr>
<td>Synergy Generation (MW)</td>
<td>8736</td>
<td>1106.29 (289.23)</td>
<td>1057.17 (300.38)</td>
<td>49.12</td>
<td>11.00</td>
</tr>
<tr>
<td>Non-Synergy Generation (MW)</td>
<td>8736</td>
<td>769.63 (154.85)</td>
<td>814.73 (196.15)</td>
<td>-45.10</td>
<td>-16.85</td>
</tr>
<tr>
<td>Synergy inv. semi-elast. (η)</td>
<td>8736</td>
<td>5.45 (77.41)</td>
<td>7.34 (23.56)</td>
<td>-1.89</td>
<td>-2.18</td>
</tr>
<tr>
<td>Day-ahead price ($/MWh)</td>
<td>8736</td>
<td>50.85 (16.92)</td>
<td>39 (28.25)</td>
<td>11.85</td>
<td>33.60</td>
</tr>
<tr>
<td>Intermittent Generation (MW)</td>
<td>8736</td>
<td>75.99 (45.73)</td>
<td>78.33 (44.78)</td>
<td>-2.34</td>
<td>-3.41</td>
</tr>
<tr>
<td>Synergy coal outages (MW)</td>
<td>8736</td>
<td>81.97 (111.51)</td>
<td>88.87 (109.10)</td>
<td>-6.90</td>
<td>-4.13</td>
</tr>
<tr>
<td>Non-Synergy coal outages (MW)</td>
<td>8736</td>
<td>176.43 (68.65)</td>
<td>42.93 (78.20)</td>
<td>133.50</td>
<td>119.77</td>
</tr>
<tr>
<td>Synergy gas outages (MW)</td>
<td>8736</td>
<td>100.37 (110.09)</td>
<td>86.57 (110.50)</td>
<td>13.79</td>
<td>8.25</td>
</tr>
<tr>
<td>Non-Synergy gas outages (MW)</td>
<td>8736</td>
<td>68.46 (104.22)</td>
<td>56.93 (37.35)</td>
<td>11.54</td>
<td>9.72</td>
</tr>
</tbody>
</table>

An observation is a half hour market, giving 182*48 = 8736 observations per half year.
Table 2: Vertical integration: Western Australian wholesale electricity market statistics for the January-July before and after the removal of the carbon tax, 2014

<table>
<thead>
<tr>
<th>Variable</th>
<th>N</th>
<th>Mean (sd) tax</th>
<th>Mean (sd) no tax</th>
<th>Mean diff. tax - no tax</th>
<th>t-stat</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Generation (MW)</td>
<td>8688</td>
<td>1978.62 (422.85)</td>
<td>1943.41 (439.28)</td>
<td>35.21</td>
<td>5.38</td>
</tr>
<tr>
<td>Emissions (Tons)</td>
<td>8688</td>
<td>753.68 (158.40)</td>
<td>736.64 (159.79)</td>
<td>17.04</td>
<td>7.06</td>
</tr>
<tr>
<td>Emissions per 1000MWh</td>
<td>8688</td>
<td>381.22 (11.46)</td>
<td>379.69 (12.03)</td>
<td>1.53</td>
<td>8.60</td>
</tr>
<tr>
<td>Synergy Generation (MW)</td>
<td>8688</td>
<td>1156.89 (313.76)</td>
<td>1051.20 (292.82)</td>
<td>105.70</td>
<td>22.96</td>
</tr>
<tr>
<td>Non-Synergy Generation (MW)</td>
<td>8688</td>
<td>807.26 (138.88)</td>
<td>878.82 (182.78)</td>
<td>-71.57</td>
<td>-29.06</td>
</tr>
<tr>
<td>Synergy inv. semi-elast. (η)</td>
<td>8688</td>
<td>4.06 (11.32)</td>
<td>4.91 (24.58)</td>
<td>-0.84</td>
<td>-2.91</td>
</tr>
<tr>
<td>Day-ahead price ($/MWh)</td>
<td>8688</td>
<td>60.26 (14.92)</td>
<td>38.04 (16.8)</td>
<td>22.23</td>
<td>92.2</td>
</tr>
<tr>
<td>Real-time price ($/MWh)</td>
<td>8688</td>
<td>59.6 (24.21)</td>
<td>42.19 (32.33)</td>
<td>17.41</td>
<td>40.18</td>
</tr>
<tr>
<td>Intermittent Generation (MW)</td>
<td>8688</td>
<td>92.24 (52.23)</td>
<td>93.06 (53.11)</td>
<td>-0.82</td>
<td>-1.03</td>
</tr>
<tr>
<td>Synergy coal outages (MW)</td>
<td>8688</td>
<td>53.05 (106.73)</td>
<td>175.70 (138.29)</td>
<td>-122.65</td>
<td>-65.45</td>
</tr>
<tr>
<td>Non-Synergy coal outages (MW)</td>
<td>8688</td>
<td>63.77 (73.81)</td>
<td>36.27 (72.78)</td>
<td>27.50</td>
<td>24.73</td>
</tr>
<tr>
<td>Synergy gas outages (MW)</td>
<td>8688</td>
<td>125.30 (128.39)</td>
<td>115.47 (101.37)</td>
<td>9.83</td>
<td>5.60</td>
</tr>
<tr>
<td>Non-Synergy gas outages (MW)</td>
<td>8688</td>
<td>124.82 (129.77)</td>
<td>46.82 (78.00)</td>
<td>78.0</td>
<td>48.02</td>
</tr>
</tbody>
</table>

An observation is a half hour market, giving 181*48 = 8688 observations per half year.

To further examine the market conditions where market power changed with a carbon tax, figure 6a displays the mean change in Synergy’s ability to raise prices after the introduction of the carbon tax for 100MW bins of market generation less online coal and gas cogeneration capacity. Partitioning the sample into these bins may be important as we observed in figure 4 that the biggest effect the carbon tax had on the market marginal cost curve was at the threshold from coal to conventional gas generation. If market generation less online coal and gas cogeneration capacity is equal to zero, then all generation in theory could be provided by the coal and cogen facilities. Therefore, we may expect to see a large market power reduction around this threshold because figure 4 illustrates that the tax smoothed the market marginal cost curve dramatically at this level of output. Indeed, we see that there was essentially no difference in Synergy’s ability to increase prices for generation levels well below this threshold, however, for levels between -100 and 100 we observe high variation in their ability to move prices. However, for generation levels well exceeding the capacity levels of coal and cogen, we observe that Synergy had much lower levels of market power in the taxed sample. In contrast, when there was a vertically integrated firm in the market, figure 6b displays almost no differences with or without
a carbon tax on Synergy’s market power for any value of generation less coal and cogen capacity.

Figure 7a displays the mean change in the emissions intensity of generation after the introduction of the carbon tax for 100MW bins of market generation less online coal and gas cogeneration capacity. We observe that for all levels, emissions were on average higher with a tax, with the biggest change occurring at levels just beyond where the coal and cogeneration capacity could have produced all of the market generation. Figure 7c displays the changes in the share of market generation by fuel type and owner, showing that the changes in emission levels are strongly correlated with the changes in Synergy coal based generation. Further, it shows that Synergy increased its generating share, particularly at levels of generation beyond the ability of coal and cogen to meet the market generation levels. In contrast, when the market contained a vertically integrated firm, figure 7b displays almost no changes in emissions with a carbon tax for when coal and cogen capacity could meet the market generation level. However, we again observe that the emission differences are highly correlated with changes in Synergy’s coal based generation.

Taking together the statistics displayed in tables 1 and 2 and figures 6a, 6b, 7a, 7b, 7c and 7d, we see some patterns that motivate further econometric analysis. Although the unconditional sample means show that emissions were higher with a tax under both market structures, the large mean differences in outage levels suggest a more considered estimation approach if we wish to assess the impact of the tax. Further, the emission differences in the taxed and untaxed samples is nonlinear in the dimension of market generation less coal and cogen online capacity. Therefore, an econometric approach that allows for a flexible functional form with respect to market conditions, including market generation and outage levels, will be used to estimate the impact of the carbon tax on the outcome variables of interest, such as carbon emissions and Synergy’s ability to increase prices.
Figure 6: Differences in market power under a carbon tax versus no tax by 100MW bins of market generation less online coal and cogen capacity

(a) No vertical integration: Synergy market power differences
(b) Vertical integration: Synergy market power differences

(c) No vertical integration: Histogram of market generation less online coal and cogen capacity
(d) Vertical integration: Histogram of market generation less online coal and cogen capacity

The horizontal axis at 0 is a threshold where the market generation level could have been fulfilled using only coal and gas cogeneration power plants. The value of the market power measure in each period is calculated by equation (4): \( \eta = \frac{Q^*}{100DR(\bar{P}^{*})} \), corresponding to the $/MWh increase in the day-ahead market price for a 1% reduction in Synergy generating output. For sub-figures a and b, the vertical axis represents the taxed sample mean less the untaxed sample mean. The no vertical integration sample compares Jan 1 - Jun 30 2013 (tax) to Jan 1 - Jun 30 2012 (no tax). The vertical integration sample compares Jan 1 - Jun 30 2014 (tax) to Jan 1 - Jun 30 2015 (no tax). The Synergy market power difference is greater than zero if Synergy had a greater ability to increase market prices during the carbon tax sample.
Figure 7: Differences in emissions intensity and fuel mix under a carbon tax versus no tax by 100MW bins of market generation less online coal and cogen capacity

(a) No vertical integration: Emissions intensity difference

(b) Vertical integration: Emissions intensity difference

(c) No vertical integration: Fuel mix differences

(d) Vertical integration: Fuel mix differences

The horizontal axis at 0 is a threshold where the market generation level could have been fulfilled using only coal and gas cogeneration power plants. In each sub-figure, the vertical axis represents the taxed sample mean less the untaxed sample mean. The no vertical integration sample compares Jan 1 - Jun 30 2013 (tax) to Jan 1 - Jun 30 2012 (no tax). The vertical integration sample compares Jan 1 - Jun 30 2014 (tax) to Jan 1 - Jun 30 2015 (no tax). The emissions intensity difference is greater than zero if the emissions intensity was higher during the carbon tax sample.
5  Empirical Strategy

5.1  Measuring the responses to the carbon tax

Figures 7a and 7b estimated the mean of emissions conditional on equilibrium generation less coal and cogen capacity levels. To control for a wider range of confounding factors, I employ a semi-parametric estimator described in Robinson (1988) that compares conditional mean differences with and without the carbon tax. Including nonparametric components to estimate the impact of the carbon tax is useful as it allows for market outcomes to be related in an unspecified manner to load, forecast, intermittent generation and outage levels. This avoids attempting to model the complexity of a multi-player, supply function game with uncertainty.

The Robinson estimator is used to estimate the conditional mean of the market outcomes of interest. Denote \( y_t \) as a market outcome value for a half-hour market \( t \) in our sample. Denote \( Z_t \) as a vector of continuous control variables for the corresponding market period, and \( X_t \) as a vector of binary control variables. \( y_t \) is either half hour carbon emissions, Synergy coal generation, Synergy gas generation, non-Synergy coal generation, non-Synergy gas generation, the Synergy inverse semi-elasticity of residual demand (\( \eta \)), real-time wholesale electricity price or day-ahead wholesale electricity price. \( Z_t \) is 10 dimensional, comprised of forecasts 24 hour and 1 hour before \( t \), market generation, load, intermittent generation, the market-wide generating capacity that is offline and the amount of Synergy coal, Synergy gas, non-Synergy coal and non-Synergy gas capacity offline.\(^{15} \)

\( X_t \) comprises of \( T_t \), a dummy variable for whether emissions were subject to the carbon tax, and half-hour-of-day and day-of-week dummy variables. Using the approach in Robinson (1988), assuming \( E(\epsilon_t|X_t, Z_t) = 0 \), allows estimation of the coefficients on the control variables contained in \( X_t \):

\[
y_t = \beta'X_t + f(Z_t) + \epsilon_t \quad (5)
\]

\[
\therefore E(y_t|Z_t) = \beta' E(X_t|Z_t) + f(Z_t) \quad (6)
\]

\[
(5) - (6) \Rightarrow y_t - E(y_t|Z_t) = \beta'(X_t - E(X_t|Z_t)) + \epsilon_t \quad (7)
\]

Robinson (1988) shows that the Ordinary Least Squares (OLS) estimate for \( \beta \) is \( \sqrt{N} \) consistent when inserting nonparametric estimators for \( E(y_t|Z_t) \) and \( E(X_t|Z_t) \).\(^{16} \) This procedure is performed using a Normal(0,1) kernel and a cross-validated bandwidth that minimizes the sum of squares of the residual from the OLS regression. The estimate of \( \beta_{Tax} \) from this procedure can be interpreted as an estimate of the mean difference in the outcome variable under a tax and no tax after controlling for variables in \( Z \) and \( X \).\(^{17} \)

\(^{15} \)With no transmission losses, market generation equals load less intermittent generation. Inclusion of these highly collinear terms do not impact the results, but are included to capture transmission losses. The market outages and the four owner/fuel outages are again highly collinear, however, other fuel outages are excluded making them not linearly dependent. Further, the market outages are total outages, the firm/fuel outage variables are planned outages.

\(^{16} \)Specifically, I calculate \( \hat{E}(y_t|Z_t) = \frac{\sum_{i=1}^T K((Z_t - Z_i)/h)y_i}{\sum_{i=1}^T K((Z_t - Z_i)/h)} \) and \( \hat{E}(X_t|Z_t) = \frac{\sum_{i=1}^T K((Z_t - Z_i)/h)X_i}{\sum_{i=1}^T K((Z_t - Z_i)/h)} \).

\(^{17} \)The specification of a separable non-linear function of \( Z_t \) in (5) is very similar to the specification in Cullen and Mansur (2014) and Wolak (2015). Given the large sample size at my disposal, I use the Robinson estimator with a
a flexible functional form of $Z$, consider the case in which $X_t$ only contains $T_t$ and $Z_t = z$ only when $T_t = 1$. Consequently, $E(T_t|Z_t = z) = T_t = 1$. Therefore,

\[ y_t - E(y_t|Z_t) = \beta'(T_t - E(T_t|Z_t)) + \epsilon_t \]

\[ y_t - E(y_t|Z_t = z) = \beta'(T_t - E(T_t|Z_t = z)) + \epsilon_t \]

\[ \Rightarrow y_t - E(y_t|Z_t = z) = \epsilon_t \]

This illustrates that $\beta$ is identified from comparisons of observations where $Z_t$ is observed in both the taxed and untaxed sample. Consequently, the parameter captures the average effect over the values of $Z_t$ that are observed in both samples. A consequence of this is that the estimate of $\beta$ will be dependent on the sample window chosen if there is heterogeneity in the treatment effect, and that perfect predictors of the probability an observation is in the taxed sample can not be included in $Z_t$. For this reason, the same calendar months are used for each sample. The perfect predictor requirement forces imposing an additional assumption on the model, that fuel input spot prices do not enter $Z_t$. Figure A2 displays the plots the closest fuel spot price data available: the Newcastle thermal coal price, and the gasTrading spot market gas price. The Newcastle price reflects prices on the other side of the continent for potentially a different grade coal than that used in Western Australia, and the gasTrading gas price is a privately run exchange for Western Australian natural gas. Unfortunately both price series are at a month level and exhibit a strong trend over the sample window, resulting in these series being perfect predictors for an observation being in the taxed or untaxed sample. This assumption is plausible if generators enter long-term fuel procurement contracts that were not altered by the carbon tax. Evidence that supports the lack of variation in generator fuel costs can be found in Buckley (2014), where it is quoted that Synergy entered a 20 year, fixed price, coal supply contract with Premier Coal, beginning in 2011. While the spot prices may bear little resemblance to the marginal costs implied by generator contracts, if contracts are renegotiated on an annual basis they suggest that both coal and gas prices may have been falling at the time the tax was removed.

To further test the predictions in section 3, equation (7) is estimated separately on partitioned samples defined by the by the market generation less coal and cogen capacity levels. From the stylized model and figures 6a, 6b, 7a, 7b, 7c and 7d, we see that the tax could have substantially different outcome for values less than -100, between -100 and 100 and greater than 100. This will emphasize any heterogeneity in market power by market generation levels.

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18 The calendar months are January to July, given that the vertically integrated, taxed sample only has a 6 month window in the data covering these months.
19 Given that the balancing market began the day the carbon tax was introduced, an obvious additional assumption is that the introduction of the balancing market had no effect on the market outcomes analyzed if we are to interpret the coefficient as the mean difference induced by the carbon tax. Given the minor amount of trade in the balancing market and the large changes to firm cost curves that occurred with the carbon tax, it may be reasonable to assume most differences are attributable to the carbon tax but this claim is untestable.
20 I am grateful to gasTrading Australia Pty Ltd for giving me access to these data.
21 Buckley (2014) also highlights that the coal contract was “bailed out” in 2015, after the sample window used for analysis closed.
5.2 Measuring the perfectly competitive counterfactual

To compare the impact the tax had on emissions in a given market organization of Western Australia versus that of a perfectly competitive (or regulated monopoly) regime where all generators produce in order of marginal cost, I simulate market outcomes using realized demand and outage data. Here, for each half-hour market, I order the generators that reported being online\(^{22}\) in order of marginal costs and assume they output at full capacity until the realized generation from that half-hour was met. Using the emission characteristics of the generators and this assumed production schedule, I aggregate market emissions for the 4 sample windows used in the analysis and compare their means for descriptive purposes.

6 Results

6.1 Sample selection by date window

Table 3 contains estimates on the average carbon tax impact on market outcomes using the Robinson technique in equation (7). The table use a sample from the introduction of the carbon tax (January 1 - July 1 2012, no tax; with January 1 - July 1 2013, tax) and a separate sample when the market had a vertically integrated generator, (January 1 - July 1 2015, no tax; with January 1 - July 1 2014, tax). The interpretation of the coefficient from the non-vertically integrated market structure captures the introduction of the carbon tax and the introduction of the real-time balancing market.

Focusing on the impact of the tax introduction in 2012, Column I of table 3 displays the estimated coefficients on the tax dummy from equation (7), with the rows defining the dependent variable. For the impact on emissions, the results imply that all else equal, there was a 13.3 ton increase in emissions (approx. 1.8%, statistically different from zero at a 1% level). For the large part, this appears driven by the average increase in Synergy coal based generation of 28.34 MWh and reduction of non-Synergy gas generation of 37.88 MWh per half hour. However, after controlling for the market characteristics the model does not detect that the tax had an impact on Synergy’s ability to increase prices. These results contrast to the findings in Column II of table 3 that measures the average effect from removing the tax when Synergy was vertically integrated. First, we observe a modest reduction in carbon emissions of 4.77 tons (0.6%, statistically different from zero at a 1% level). Given we observed the unconditional mean of carbon emissions rose with the tax, this result implies that once controlling for market conditions such as outages, emissions were lower with the tax on average. We observe that Synergy has higher production with the tax, however, the increases in coal production and gas production were almost exactly offset by corresponding reductions in other firm coal and gas production to result in a slight emissions reduction overall. In all cases, real-time and day-ahead prices are detected to have increased with the tax by between $11 and $23 per MWh, which roughly corresponds to the tax per MWh a gas and coal generator would pay, respectively.\(^{23}\)

\(^{22}\)Generator capacity is defined as the capacity credits they possess, less the MW outage levels they reported for that half-hour.

\(^{23}\)A $24.15 per ton of carbon dioxide on a .5t/MWh gas plant and 1t/MWh coal plant results in $12.08 and $24.15 tax per MWh increases in gas and coal generator marginal costs. The different effects on the day-ahead and real-time markets may arise from different levels of competition in the two markets, as less generators are able to participate in the real-time market.
Table 3: Semi-parametric estimates of carbon tax impact on market emissions and prices

<table>
<thead>
<tr>
<th>No tax Sample window</th>
<th>Tax Sample window</th>
<th>Market structure</th>
<th>I</th>
<th>II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emissions</td>
<td>13.33**</td>
<td>-4.47**</td>
<td>(1.25)</td>
<td>(0.65)</td>
</tr>
<tr>
<td>Synergy coal gen</td>
<td>28.34**</td>
<td>8.22**</td>
<td>(2.40)</td>
<td>(1.48)</td>
</tr>
<tr>
<td>Synergy gas gen</td>
<td>7.15**</td>
<td>27.12**</td>
<td>(2.34)</td>
<td>(1.21)</td>
</tr>
<tr>
<td>Non-Synergy coal gen</td>
<td>-3.87*</td>
<td>-7.13**</td>
<td>(1.85)</td>
<td>(0.72)</td>
</tr>
<tr>
<td>Non-Synergy gas gen</td>
<td>-37.88**</td>
<td>-29.06**</td>
<td>(1.95)</td>
<td>(1.03)</td>
</tr>
<tr>
<td>Synergy inverse semi-elast ($\eta$)</td>
<td>1.14</td>
<td>-1.62+</td>
<td>(3.12)</td>
<td>(0.97)</td>
</tr>
<tr>
<td>Real-time price</td>
<td>.</td>
<td>12.54**</td>
<td>.</td>
<td>(0.46)</td>
</tr>
<tr>
<td>Day-ahead price</td>
<td>11.28**</td>
<td>19.41**</td>
<td>(0.55)</td>
<td>(0.18)</td>
</tr>
</tbody>
</table>

Key: ** P-value less than 1%, * P-value less than 5%, + P-value less than 10%.

Estimates of the coefficient corresponding to the tax dummy variable in equation (7). Each cell represents a different model, with the row corresponding to the outcome variable and column to the sample selection. Sample sizes for 2012 model is 17568 and for the 2014 model is 17520. $X$ contains day-of-week and half-hour-of-day fixed effects, $Z$ contains 1 and 24 hour load forecast, load, intermittent generation, total outages, planned Synergy coal outages, planned Synergy gas outages, planned non-Synergy coal outages and planned non-Synergy gas outages. For Column I, there is no data for Real-time price and 1 hour load forecast. Robinson (1988) robust standard errors provided in parentheses.

6.2 Market generation partitions

The predictions from section 3 were tied to levels of market generation that could be completely supplied by coal and cogen gas given the carbon tax smoothed the market marginal cost curve at that level of generation. Table 4 displays results for the three partitions of generation less online capacity: less than -100 where coal and cogen could easily meet the market demand; -100 to 100, where the demand could roughly be met by coal and cogen generators; and more than 100 where conventional gas generators must be used to meet market demand. Column III (greater than 100) matches the predictions from section 3 better than columns I and II for the introduction of the tax when no firm was vertically integrated as there was a statistically detectable reduction in Synergy's ability to increase prices with the tax. Even after adding the controlling variables in the Robinson estimation, we still see little precision in the market power.
estimates at the -100 to 100 range where the residual demand curves of firms were expected to change the most with the tax. Further, we see that the smallest magnitudes of outcome changes are in the low levels of generation that can be fully met by coal and cogen gas generators. Given the market marginal cost curves are relatively flat at these low levels of demand with and without a carbon tax, this appears reasonable. For the vertically integrated sample, we see a reduction in emissions for all partitions, but again the smallest magnitude of change is seen in the low levels of generation. The vertically integrated sample has almost no changes in coal plant output in periods where market generation levels that exceed the coal and cogen capacity, which is consistent with a more competitive supply level since the tax was not large enough to make coal generation more expensive than conventional gas generators.

Table 4: Semi-parametric estimates of carbon tax impact on market emissions and prices: Partitions by total market generation less online coal and cogen capacity

<table>
<thead>
<tr>
<th>Market structure</th>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>VI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Generation less online coal and cogen capacity (MW)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; −100</td>
<td></td>
<td></td>
<td></td>
<td>−3.61**</td>
<td>−8.64**</td>
<td>−8.92**</td>
</tr>
<tr>
<td>−100, 100</td>
<td></td>
<td></td>
<td></td>
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<td>(1.26)</td>
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<td>34.51**</td>
<td>23.85**</td>
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<td>−23.57**</td>
<td>−9.84**</td>
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<td>(2.85)</td>
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<td>(3.09)</td>
<td>(2.55)</td>
<td>(1.74)</td>
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<tr>
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<td>42.50**</td>
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<td>(5.80)</td>
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<td>(3.09)</td>
<td>(2.55)</td>
<td>(1.74)</td>
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<td>−11.57**</td>
<td>29.57**</td>
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<td>2.65**</td>
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<tr>
<td>(2.39)</td>
<td>(4.28)</td>
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<td>(0.67)</td>
<td>(0.145)</td>
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<td>(1.95)</td>
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<tr>
<td>(0.47)</td>
<td>(1.01)</td>
<td>(0.21)</td>
<td>(0.57)</td>
<td>(0.45)</td>
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<td>(1.95)</td>
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<td>Day-ahead price</td>
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<td>22.41**</td>
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<tr>
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<td>(1.01)</td>
<td>(0.21)</td>
<td>(0.41)</td>
<td>(0.35)</td>
<td>(0.41)</td>
<td>(1.95)</td>
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Key: ** P-value less than 1%, * P-value less than 5%, + P-value less than 10%. Estimates of the coefficient corresponding to the tax dummy variable in equation (7). Each cell represents a different model, with the row corresponding to the outcome variable and column to the sample selection. Sample sizes for model in columns I is 6984, column II is 2934, column III is 7597, column IV is 6155, column V is 2903 and column VI is 8319. X contains day-of-week and half-hour-of-day fixed effects, Z contains 1 and 24 hour load forecast, load, intermittent generation, total outages, planned Synergy coal outages, planned Synergy gas outages, planned non-Synergy coal outages and planned non-Synergy gas outages. For Columns I, II and III, there is no data for Real-time price and 1 hour load forecast. Robinson (1988) robust standard errors provided in parentheses.
6.3 Descriptive extension: Hypothetical impact of the tax under a perfectly competitive baseline

The results presented in the previous two sections are consistent with the carbon tax lowering the incentive for Synergy to exercise market power in some market conditions when it was not a vertically integrated generator, potentially resulting in a more emissions intensive market generation mix. However, it is unclear how the equilibrium emissions would have responded if firms supplied at cost in a perfectly competitive or regulated monopolist environment. When using the existing market outcomes over the January 1 - July 1 2012 and 2013 window, and calculating emissions under the assumption that generators generate in order from lowest cost to highest if they were online for a given period, emissions are lower with the carbon tax by 16.6 tons per half hour. This emissions reduction is in strong contrast to the 13.3 ton increase estimated in column I of table 3 and the means presented in the descriptive statistics. This result shows that the carbon tax would be expected to reduce emissions under a perfectly competitive market environment, highlighting the importance of the market structure in the estimated increase in emissions.

When performing the same competitive supply counterfactual to the January 1 - July 1 2014 and 2015 window when Synergy was vertically integrated, emissions are lower with the carbon tax by 5.2 tons per half hour, slightly exceeding the 4.5 ton reduction estimated from the Robinson estimation in column II of table 3. Although not proof that the market behaved more like a perfectly competitive market once Synergy became vertically integrated, it does suggest that the emissions impact of a carbon tax is similar to the impacts expected under perfect competition. Together, the two sets of results suggest that carbon emissions and their responsiveness to changes in relative coal and gas prices from an emissions tax (or shale gas boom) can differ greatly across market structures.

A caveat from these descriptive results is that the assumption that emission and marginal cost rates are constant for all levels of output for each generator is very strong. Even a regulated monopolistic generating firm would not follow the exact rule of dispatch from cheapest to most expensive generator at full capacity because generator characteristics do differ from these assumptions. However, the results do provide some insight by confirming the theoretical expectation that emissions must fall with a carbon tax in a perfectly competitive market.

7 Discussion and final remarks

Carbon pricing makes it more expensive to emit carbon emissions. However, in imperfect markets, it is possible that increased costs can increase output in the short-term where firms are restricted by being unable to alter their capital stock. This paper provides just one example of where this issue can come about and provides a lesson of caution when applying taxes to imperfect markets if seeking short term results. The crucial features that will determine the effectiveness of a tax are the market structure and the size of the tax. If short term responses to an emissions tax are desired by policy makers, then taxes that are designed to reduce the cost advantage of coal electricity generation relative to gas electricity generation without changing the order of cost advantage could result in higher electricity sector carbon emissions due to changes in market power. However, if the market is competitively organized, or the structure is
such that the participants behave competitively (perhaps due to vertical integration), then it is less likely to observe emissions increasing with a carbon tax.

In addition to the efficiency benefits of well-designed markets that have more competitive outcomes, the ability to introduce effective corrective taxation is also higher in these markets. While it appears that the carbon tax somewhat corrected a market power inefficiency by removing the large cost advantage of coal-fired electricity generation and smoothening Synergy’s residual demand curve, it may have increased emissions by the same stroke. However, once Synergy was vertically integrated and perhaps the market participants had greater incentives to behave competitively, the carbon tax appeared to have induced a modest emissions reduction. These results support the forecasts of Cullen and Mansur (2014) that the short-run effects from carbon taxation in the USA could be rather modest. Further, the results give insight as to how the competitive organization of a market will dictate the effectiveness of a tax and further inform the finding from Knittel, Metaxoglou, and Trindade (2015) that emissions reductions in the USA from the shale gas boom were smallest in restructured electricity markets. Given the political motivations behind introducing a tax are to reduce emission levels, these modest or unexpected short-run results may be undesirable, despite the obvious long-run incentives the tax would have provided had it been introduced on a permanent basis.

Since the marginal cost estimates in this paper came from separate publicly accessible consultancy reports commissioned by the Western Australian IMO and the Australian Government, future policy makers could perform a simple, preemptive check of the impact on market marginal cost curves from the introduction of the carbon tax. Figure 8 is an analogue to figure 5, displaying Synergy’s residual demand and market level emissions as a function of their generation for a load of 2000MW under a $40/tCO2 tax. With the $24.15 tax, we saw very little movement in the merit order of generation, with coal still largely cheaper than gas, but a large change in the slope of the residual demand curve. With this higher tax we now see substantial changes in the merit order of generation. We still observe a flatter residual demand curve, but the market emissions for levels of Synergy generation are up to 25% lower, with the inverted-V shape of the market level emissions function wiped out. While this does not imply that the optimal tax is $40, it does illustrate how sensitive an immediate reduction in emissions for a given demand level will be to the tax size chosen.

As a final remark, the empirical findings in this paper are specific to the small, isolated market of Western Australia. The results should encourage policy makers to carefully consider the potential short-run impacts the tax can have on electricity markets when designing their policy, and the relevance of market structure to their policy objectives. However, the analysis in this paper do not provide a reason to not engage in carbon pricing. Given the life-cycle of electricity generators may be in the range of 20-50 years, and a political divide in Australia resulted in a politically unstable two-year emissions tax, these results should not be used to assess the merits of future emissions taxes. A stable carbon price should provide strong investment incentives for new capital stock to be less emissions intensive. Therefore, the results support the position that the base of the carbon tax should be set broader than just the electricity sector given the modest short-run emission changes, and will need to be long term to have substantive impacts. It is left as future work to empirically estimate the impacts of carbon taxation on investment incentives.
Figure 8: Synergy residual demand and market level carbon emissions as a function of Synergy generation for load of 2000MW, no tax and tax = $40

Figures constructed from data in Table B1, assuming fixed demand of 2000MW. Market-wide emissions assumes that 2000MW of electricity is generated, with Synergy generating $x$MW using its cheapest generators and non-Synergy firms generating $(2000 - x)$MW using their cheapest generators.

and to assess long-run carbon emission impacts in electricity generation from carbon taxation.
References


A Additional figures
Figure A1: Generation levels, carbon emissions and market prices, 2011-2015

(a) Daily average of half-hour market generation

(b) Daily average of half-hour carbon emissions

(c) Daily average of half-hour Synergy generation

(d) Daily average of half-hour day-ahead electricity market price

Vertical lines correspond to introduction and removal of the carbon tax. Each marker is the average value for the 48 half-hour values on that given day.
Figure A2: Coal and gas price indicators, 2011-2015

(a) Average monthly Newcastle thermal coal, $/ton  
(b) Av. monthly gasTrading spot gas price, $/GJ

Vertical lines correspond to introduction and removal of the carbon tax
Sources: http://www.indexmundi.com/commodities/?commodity=coal-australian&months=60
and gasTrading Australia Pty Ltd.

B Additional tables
Table B1: Western Australian coal and gas electricity generator characteristics, 2014

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<tr>
<th>Owner Code</th>
<th>Facility Code</th>
<th>Capacity* Unit/Cum. (MW)</th>
<th>Primary Fuel**</th>
<th>SRMC (no tax) ($/MWh)</th>
<th>SRMC (w/ tax) ($/MWh)</th>
<th>Average electrical heat rate (GJ/MWh at max)</th>
<th>Average CO2-e emission intensity (t/MWh at max)</th>
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<td>ALCOA_WGP</td>
<td>24</td>
<td>Cogen gas</td>
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</table>

Notes: *: Only gas and coal generators with non-zero capacity credits listed. Generator capacity is defined as the amount of capacity credits they were allocated by the IMO in 2014. 201MW of higher cost, distillate fueled generators are omitted.

**: Variations in coal or gas type refers to different source locations and/or different long-term contract arrangements. Distillate is used as a secondary fuel for some of the other units if they have used up their gas supply.

Sources: Sinclair Knight Merz MMA (2014) and various issues. Some generator characteristics were suppressed for confidentiality reasons. If emission intensity is missing from the various issues, ACIL Allen Consulting (2013) was used. For the PRK_AG, KWINANA_CCG1 and NEERABUP_GT1 generators, the missing marginal cost estimates were replaced with the costs of the generating unit with the closest emissions factor of a gas generator. For PINJAR_GT01 to PINJAR_GT07, costs were replaced by the average of the costs for PINJAR_GT09 to PINJAR_GT11. For ALINTA_WGP_U2, it is given the same characteristics as ALINTA_WGP_GT.