Markets with Power: Competitive benchmark model of the Australian National Electricity Market

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***Abstract*—In the late 2010s, a confluence of events contributed to unprecedented price increases and volatility in the Australian National Electricity Market (NEM). We investigate to what extent market power contributed to elevated prices during this time. We base our analysis on a benchmark model of the NEM, which estimates counterfactual prices under the assumption of perfect competition. We construct marginal cost curves for each interval based on unit characteristics and fuel prices and produce a counterfactual competitive timeseries using actual demand. A comparison of actual market outcomes with our benchmark simulations suggests that, on average, a material fraction of regional prices are a result of market power. Depending on the region and time period, market power can account for 10% to 50% of wholesale prices. Moreover, our analysis indicates that market power tends to be most prevalent within the Queensland region and during high levels of regional demand across the NEM.**

***Index Terms*—Competitive Benchmark Model, Electricity Markets, Market Power, Australia**

I. Introduction

Until recently, the Australian National Electricity Market (NEM)—the wholesale electricity market operating within the eastern states of Australia—had long enjoyed a reputation as one of the most competitive and well-functioning. After 2017, however, the NEM experienced a persistent rise in prices and increased volatility [1]. Between 2012 and 2016, wholesale market prices averaged roughly 53 Australian dollars (AUD) per megawatt-hour (MWh); whereas, in subsequent years wholesale prices averaged over 94 AUD/MWh. This occurred without corresponding increases in coal prices despite it being the dominant generation technology within the NEM.

These wholesale market outcomes precipitated three federal inquiries on the effectiveness of Australia's market design and competition policy in the electricity sector [2]–[5]. Price increases were attributed to a variety of factors, including: a tightening supply-demand balance; coal supply disruptions; increasing gas prices; and, high levels of market concentration and the associated potential for market power.

In this paper, we adapt methods developed in [6] to assess the degree to which price increases can be attributable to the markups included in generator bids. We will interpret markups as a reflection of market power. An important innovation of this analysis is explicit modeling of the zonal market-clearing process in Australia, where each of the five regions are separate zones that can have different prices depending on the level of flows on the transmission lines interconnecting the states. In order to perform this calculation, we make use of the actual daily configuration of the transmission network to compute our competitive benchmark prices.

Our model relies on various data, including high-resolution electricity market data from the Australian Energy Market Operator (AEMO), as well as fuel prices and generator characteristics from other sources. It estimates counterfactual prices under the assumption of perfect competition. Thus, when compared to actual market prices, it allows us to estimate price-cost margins—a common measure of market power—for the generation sector.

A comparison of actual market outcomes with our benchmark simulations suggests that, on average, a material fraction of regional prices between July 2015 and June 2019 result from the exercise of market power. This fraction can range from 10% to 50% depending on the region and time period in question. Moreover, we find significant market power particularly within Queensland and during high demand periods.

We proceed as follows. Section II describes the NEM and its key institutional features, including its operation, structure and susceptibility to market power. Section III introduces our competitive benchmark model, while Section IV discusses our data sources. Finally, Section V discusses our results, and Section VI concludes.

II. National Electricity Market Background

The NEM is an electricity market on the eastern seaboard of Australia managed by AEMO. It is self-contained such that all load must be satisfied by generation from within the network. The network consists of five regions, namely: New South Wales (NSW), Queensland (QLD), South Australia (SA), Tasmania (TAS) and Victoria (VIC). These regions are linked radially with VIC as the hub.

The remainder of this section describes key elements of the NEM in further detail. In particular, it highlights its operation, structure and potential for market power.

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A. Market operation

The NEM is an energy-only, zonal, real-time electricity market. The 'energy-only' framework means generators are only paid for the electricity they produce. As a zonal market, supply and demand are balanced within each region and a uniform price applies at all intraregional nodes. Finally, the NEM does not utilize sequential markets; thus, it is real-time only and all scheduling is finalized within its spot market.

The market uses a double-auction format. After participants submit their offers, AEMO sets the market-clearing price and quantity at the intersection of the resulting aggregate supply curve and realized demand within each region. Generator bids consist of ten price-quantity pairs. The price bands must be increasing and are fixed the day before dispatch. Quantity bands can be submitted right up until dispatch. Essentially, generators have the flexibility to modify their bids until dispatch provided they can justify any changes under the good faith provision.[1]

AEMO also operates markets for the acquisition of ancillary services (AS) or reserve capacity. AS are used to meet unexpected changes in the supply-demand balance and to adjust production in order to minimize congestion. AS markets likely impact the energy spot price and, therefore, should be considered in any market-wide modeling.

B. Market structure

The NEM has been concentrated since its inception. This was noted early on by [7], who emphasized how outcomes could be adversely impacted by increased concentration and limited competition. Since then, generation within the NEM has experienced significant horizontal re-aggregation. These concerns were revisited in the recent electricity market reviews [2]–[5].

Table I displays generation capacities within the NEM by major firm and region. While it presents results for 2019, they are indicative of the market structure across our period of interest.[2] The concentration ratio of the top three firms (CR_3) by capacity is below 50%. Thus, at the NEM-level, the market appears only moderately concentrated. Nonetheless, within individual regions, concentration is significantly higher: above 77% within NSW; 64% within QLD; 70% within VIC; 68% within SA; and, equal to 100% within TAS. Higher concentration at the regional level is partly an artifact of how the NEM was constituted; whereby, five independent electricity markets were connected by a small number of interconnectors.

C. Market power

Given its energy-only design and high price cap, the NEM relies heavily on effective competition to deliver cost-reflective price outcomes. This is especially true given the limited set of rules governing how generators can bid into the market. Generators are only constrained by the price cap and the good faith rebidding provision, neither of which prevent participants from exercising market power [3].

The intended benefit of a loosely-regulated, energy-only electricity market is the provision of clear price signals for the value of generation. Energy-only electricity markets are designed to arrive at the 'efficient' price for electricity supply, with the accepted drawback that occasional high price events are necessary for signaling when new capacity is needed [4]. These features of the market design require competition among rival generators to drive efficient prices. Thus, while the energy-only design of the NEM means the market should deliver clear and efficient prices, it is nevertheless a design vulnerable to the exercise of market power. This is before considering common factors which exacerbate the potential exercise of market power within electricity markets, including: inelastic demand and supply, transmission constraints, and repeated interactions [6].

TABLE I
CAPACITY BY REGION IN 2019

Firm	**NSW**	**QLD**	**VIC**	**SA**	**TAS**	**Total**
AGL Energy	5,403	677	3,626	1,792	0	11,498
Snowy Hydro	5,149	0	3,015	281	0	8,445
Origin Energy	4,093	1,578	629	1,016	0	7,315
EnergyAustralia	2,435	93	2,775	351	0	5,654
CS Energy	0	4,251	0	0	0	4,251
Stanwell Corp.	96	4,155	0	0	0	4,251
Hydro Tasmania	0	0	94	100	1,543	1,737
Engie	78	0	0	1,117	0	1,194
Other	3,180	4,678	3,206	1,097	0	12,160
Total	20,433	15,431	13,344	5,754	1,543	56,506

Note: All values in MW.

III. Competitive Benchmark Model

Within electricity markets, the difference between price and marginal cost of the most expensive unit required to meet demand is the fundamental measure of market power. Assuming no market power, the absence of non-convexities, and a lack of other distortions, all units with a marginal cost below the market price produce. Nonetheless, a naive comparison of the market price to the marginal cost of the marginal unit may not be an accurate measure of market power. Economic withholding—that is, when a firm strategically reduces output or raises its offer price—necessitates the replacement of its production by other, more expensive generation that may be produced by nonstrategic units. Therefore, to generate a reliable measure of market power, we must estimate the system marginal cost of serving a given demand if all firms were behaving as price-takers. In the following subsections, we describe the assumptions and data used for our competitive

[1] The good faith provision obligates participants not to make false or misleading offers. That is, a rebid should only be submitted if there is a change in the underlying material conditions upon which the offer was based.

[2] Note that capacities are associated with traders and not necessarily owners. For the majority of plants, these are equivalent.

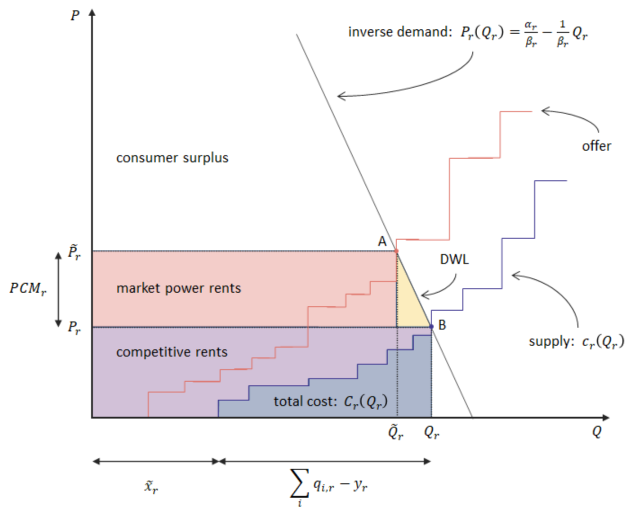

Fig. 1. Welfare maximization problem for region r.

benchmark model and for generating estimates of the system marginal cost of supplying electricity in the NEM.[3]

To construct a model of the NEM under perfect competition, we assume wholesale electricity is a homogeneous commodity and all units act in a manner consistent with perfect competition.[4] Finding the equilibrium solution based on a perfectly competitive market is identical to maximizing total welfare. Thus, for each time period $t \in \{0, \ldots, S\}$, a perfectly competitive market outcome is obtained by solving the following welfare maximizing problem:

$$\max_{q_{i,r,t}} W_t = \sum_r \sum_i \Big[P_{r,t}(Q_{r,t}) - c_{i,r,t} \Big] \cdot q_{i,r,t} \tag{1}$$

where the output of unit i from region r at time t is represented by $q_{i,r,t}$ and is limited by its capacity: $q_{i,r,t} \leq \overline{q}_i$. Simulated regional prices for region r and period t are given by function $P_{r,t}(\cdot)$ and simulated regional demand by $Q_{r,t}$. Marginal costs are defined as $c_{i,r,t}$ and are unit- and time-specific. Fig. 1 summarizes the maximization problem visually, while the following subsections address its various components.

A. Market demand and prices

We use the generation of fossil-fired units $q_{i,r,t}$ to construct the residual demand for electricity within each region. Thus, our estimate does not represent full end-use demand, but instead the portion of demand satisfied by price-following generators. In effect, we assume the operations of non-modeled units—e.g., hydro and renewables—is exogenous. The validity of this assumption is discussed further below.

[3] One caveat to our approach is that it does not explicitly account for hedging, which can affect estimated market outcomes [8], [9]. For the purposes of our model, we abstract away from hedging since it does not appear to have materially changed over during our period of interest.

[4] This assumption can be relaxed such that our simulation approach uses a different benchmark, e.g. Cournot competition [9].

Demand, as defined above, is represented by the function $Q_{r,t} = \alpha_{r,t} - \beta_r P_{r,t}$ for each region r and time period t. It yields an inverse demand curve defined as:

$$P_{r,t}(Q_{r,t}) = \frac{\alpha_{r,t} - \sum_i q_{i,r,t} - \tilde{x}_{r,t} + y_{r,t}}{\beta_r} \tag{2}$$

where $\tilde{x}_{r,t}$ represents must-take generation[5] and $y_{r,t}$ is net injections into region r.[6] The intercept, $\alpha_{r,t}$, and slope, $\beta_{r,t}$, of the demand function are time-dependent since they are based upon actual demand in each region. That is, we model a linear demand curve passing through the observed price-quantity pairs across each region and period: $\alpha_{r,t} = \tilde{Q}_{r,t} + \beta_{r,t} \cdot \tilde{P}_{r,t}$, where tildes signify actual market outcomes.In the short-run, electricity is an extremely inelastic product, resulting from consumers lack of exposure to wholesale prices and an inability to shift demand to other energy sources or times. Thus, we set the price elasticity of demand to a low value: $\varepsilon = -0.1$.[7] The slope of the demand curve is, therefore, estimated as: $\beta_{r,t} = \varepsilon \left(\frac{\tilde{Q}_{r,t}}{|\tilde{P}_{r,t}|} \right)$.

B. Fossil-fired generation

We explicitly model the individual fossil-fired units in each region. Through AEMO's Integrated System Plan (ISP) and its predecessor the National Transmission Network Development Plan (NTNDP), data on the production costs of thermal generation units are available.

Generation marginal costs are defined as the sum of fuel and variable operating and maintenance costs for each fossil-fired unit. Fuel costs are calculated as the product of the regional fuel price and a unit-specific "heat rate," which is a measure of fuel-efficiency. The marginal cost of unit i in region r at time t is, therefore, an affine function:

$$c_{i,r,t} = \frac{VOM_i + FP_{r,t} \cdot HR_i}{LF_{i,y}} \tag{3}$$

where VOM_i is the variable operating and maintenance cost per MWh and HR_i is the heat rate for unit i. The regional fuel price for coal, gas, or petroleum, $FP_{r,t}$, is described in greater detail in Section IV. Throughout our analysis, we assume that fuel prices are competitively determined. If, however, this is not the case or reported prices exceeded actual prices, then we have underestimated the full impact of market power within the NEM.

The Loss Factor, $LF_{i,y}$, varies by unit i and financial year y and is calculated as the product of the Marginal Loss Factor and the Distribution Loss Factor. As the NEM is a zonal market, these factors represent intra-regional losses. Essentially, LF represents the marginal losses for a generator to deliver electricity to the regional reference node (RRN) and, thus, allows all generation to be treated uniformly. They are

[5] Note that must-take generation includes hydro, variable renewables (i.e. solar & wind), batteries, non-scheduled generation, and AS.

[6] For simplicity, we drop price dependencies from (2) and all subsequent notation.

[7] When the market is modeled as perfectly competitive, results are relatively insensitive to the elasticity assumption, as price is set at the marginal cost of system production and the range of prices is relatively modest.

conditional on year y since AEMO fixes their values for a 12-month period starting in July.

When building regional marginal cost curves, one typically needs to constrain $q_{i,r,t}$ by an expectation of capacity. Instead, we rely on the self-reported availability of the unit, $\tilde{z}_{i,r,t}$, bid into the market. As such, we adopt the constraint that $q_{i,r,t} \leq \tilde{z}_{i,r,t}$. This inequality recreates the market outcome as accurately as possible and will understate the amount of market power if strategic withholding is being exercised.

C. Must-take generation

We model hydro, variable renewable energy (VRE), battery storage and non-scheduled generation as must-take or, equivalently, non-strategic. We assume the observed output of these units is what would be produced by a price-taking firm in a perfectly competitive market. This implies that the operations of these must-take units does not change. Following [6], this assumption biases against finding market power.

D. Ancillary services

Along with the forms of generation discussed in the previous subsection, we also model some AS as must-take generation. Many generators competing in the energy spot market are also eligible to earn payments for AS, assuming they bid successfully into one of the AS markets. These markets represent an alternative use for much of the generation capacity throughout the NEM. Since AEMO is procuring extra capacity for the provision of AS, these services should be considered as part of market-clearing demand. It is effectively withheld from the spot market and its capacity is otherwise unavailable. For this reason, we add cleared AS to demand within each NEM region.[8] We limit the expansion of demand to raise AS, since generators offering lower AS must already be producing and cannot be withheld from the spot market.[9] For context, the cleared quantity of raise AS peaked as high as 14% percent of total NEM demand, while its mean percentage was around 7% percent over our time horizon.

E. Interconnectors

We assume that inter-regional trade is managed to efficiently arbitrage price differences across regions, subject to interconnector limitations. Mathematically, we adopt an approach similar to [10] and [11] to represent the arbitrage conditions as a set of constraints within the market equilibrium. Essentially, the transmission 'flow' induced by a marginal net injection of electricity in region r can be represented by a power transfer distribution factor, $\phi_{r,l}$, which maps injections to flows over interconnector l. Given that the NEM is a radial model with VIC as the hub, a net injection, $y_{r,t} \geq 0$, in region r is assumed to be withdrawn at the hub. In fact, we assume that all net injections balance with their withdrawal in every time period t: $\sum_{r \in R} y_{r,t} = 0$. This condition is subject to the export and import flow limits—$\tilde{T}^{ex}_{l,t}$ and $\tilde{T}^{im}_{l,t}$, respectively—across interconnectors l and time periods t.

F. Price cost margins

Utilizing the assumptions outlined in the previous subsections, we solve the welfare maximization problem for the perfectly competitive market price for each region and settlement interval within the NEM from July 2015 to June 2019. Our assumptions regarding must-take generation mean that we directly apply the observed production of hydro, VRE, and AS resources for each settlement period.

Once we account for must-take generation and net injections, our competitive benchmark model finds the intersection of the residual demand curve and the marginal cost curve. We estimate the marginal cost for satisfying the residual demand with fossil-fired resources in each settlement interval. This yields an estimated regional marginal cost $c_{r,t}$, which is equivalent to the perfectly competitive regional spot price: $P_{r,t}$.

We rely on regional reference prices (RRP) $\tilde{P}_{r,t}$ for the actual market clearing prices. Price-cost margins are then calculated as the difference between the market-realized prices and the perfectly competitive benchmark: $PCM_{r,t} = \tilde{P}_{r,t} - P_{r,t}$.

IV. Data

We utilize detailed hourly market and generation data. These hourly output data are aggregated by region to develop the 'residual demand' in the simulation model. They are also combined with unit-specific cost data to produce regional supply functions for simulations of competitive outcomes.

Our primary source for market data is AEMO which publishes a non-annonymized synthesis of publicly available NEM data. It includes a rich set of variables capable of reproducing the various aspects of the NEM at the dispatch-level. The data for our unit-specific, time-dependent marginal costs are also sourced from AEMO, including heat rates as well as operating and maintenance expenditure rates from planning documents.

We collect fuel prices from a diverse set of sources dependent on the specific fuel. For natural gas, we rely on spot markets managed by AEMO, namely: the Declared Wholesale Gas Market (DWGM) in VIC and the Short Term Trading Market (STTM) in NSW, QLD and SA. For coal, we require price timeseries for the type of coal regionally available. NSW and QLD rely predominantly on black coal, while brown coal dominates in VIC and SA. For black coal, we use daily spot prices of Newcastle thermal coal from Bloomberg. For brown coal, there is a dearth of public pricing data. So, we extrapolate brown coal prices from the Newcastle spot data and a price ratio from the AEMO planning documents. For petroleum products, we require price timeseries for diesel and kerosene. The Australian Institute of Petroleum (AIP) provides daily diesel terminal gate prices within each state capital city. Kerosene price data, to our knowledge, are not publicly available for Australia. Instead, we estimate its price by adding the spread between Singaporean kerosene and diesel spot prices from Bloomberg to the state-based diesel prices from the AIP.

[8] Adding AS to demand is equivalent to shortening the supply curve by the same quantity.

[9] Raise AS is used to correct a minor drop in frequency, addressing either an increase in generation or a decrease in load.

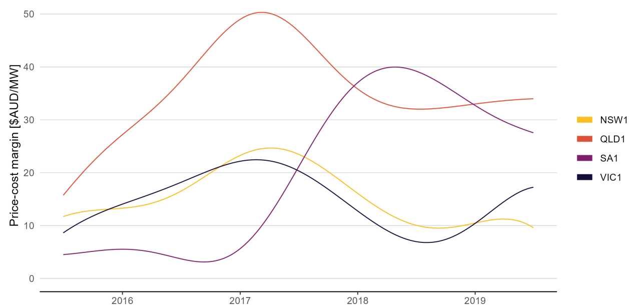

Fig. 2. Daily mean price-cost margins by region.

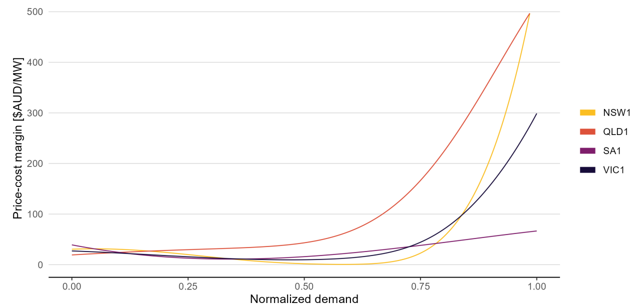

Fig. 3. Price-cost margin distributions by region.

V. Results and Discussion

Using the model and data described above, we simulate the perfectly competitive market outcome for each settlement interval between July 2015 and June 2019 inclusive. Below, we present a comparison of actual versus simulated market results.

Fig. 2 presents daily mean price-cost margins by region. Actual prices are based on RRPs from AEMO, while simulated prices are generated using our model of perfect competition and represent the market's marginal cost. The plot contains a number of noteworthy features. First, NSW, QLD and VIC all have high price-cost margins during the 2016-17 financial year and decrease thereafter. Second, despite QLD exhibiting a similar trend to NSW and VIC, its price-cost margin is typically more than double that of the other two regions. And third, SA exhibits a different trend, starting from a low value, its price-cost margins dramatically increase during 2017 when all others are decreasing.

Reassuringly, these observations are reflected in market summaries from this period [1], [12]. During the 2016-17 financial year, average spot prices increased dramatically across the NEM and remained elevated for the next few years. Upward price pressure occurred in November 2016 after the announced decommissioning of a large coal plant, representing around five percent of the NEM's capacity [13]. Its shuttering followed years of similar fossil-fired plant closures—in particular, a number of coal plants in SA—and stagnant investment in dispatchable generation. These conditions resulted in a much tighter supply-demand balance, increasing the potential for the exercise of market power across the NEM.

In fact, regulators observed that coal generators in NSW and QLD simultaneously increased their offer prices. In part, this was understood to be a consequence of increasing coal costs and supply disruptions. However, regulators also noted that surging gas prices decreased competitive pressure on baseload plants. As a result, some coal generators periodically engaged in shadow bidding: only slightly undercutting the bids of the next highest generator in the merit order [3], [14]. These effects were far greater in QLD due to its already highly concentrated generation market [7], [15]. Nevertheless, prices relented somewhat across NSW, QLD and VIC, after a market intervention by the QLD Government in June 2017 [1], [16].

While SA experienced many of the same NEM-wide shifts as the other regions, its unique characteristics resulted in a different outcome. SA is a small market with high VRE penetration and a dependence on imports. The loss of in-region coal generation was not problematic so long as there was sufficient cheap capacity available for import. However, with the loss of significant brown coal in VIC, this tipped the SA supply-demand balance whereby a single shock could expose it to extreme prices. Weather events—i.e., heatwaves and low wind—combined with a series of plant outages and network failures led to exactly this outcome between 2017 and 2019 [1]. Overall, Fig. 2 demonstrates that with tighter supply conditions along with weaker competition, generators across the NEM were able to exercise greater market power.

To emphasize this last point, Fig. 3 presents average price-cost margins as a function of normalized demand. Unsurprisingly, the relationship is exponential, where margins are much higher at greater levels of demand. Notably, margins in QLD begin increasing at lower levels of relative demand than in the other three regions. Again, this is likely a consequence of the highly concentrated market in the state.

VI. Conclusion

In this paper, we build a competitive benchmark model of the Australian NEM and produce a counterfactual competitive timeseries. Comparing this timeseries with actual market outcomes, we evaluate market power across regions and years within the NEM.

A comparison of actual market outcomes with our benchmark simulations suggests that, on average, a material fraction of regional prices between July 2015 and June 2019 are a result of market power. This fraction can range from between 10% to 50% depending on the region and time period in question. Moreover, our analysis indicates that market power tends to be most prevalent at high levels of regional demand. These conclusions should be tempered by the fact that the NEM is an energy-only market, where the marginal generator must bid above their marginal cost or risk being unable to cover their capital expenditures [17], [18]. As such, some market power may be efficient; however, there is a question over how much is appropriate.

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