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The future of electricity generation in Australia: A case study of New South Wales

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ABSTRACT

The Australian electricity industry has found itself the subject of an intense political debate. At the center is the role of coal-fired generation. The most economic form of new generation technology in Australia is wind on a levelized cost of energy (LCOE) basis. However, new wind generation must be 'firmed' to address variability in output. The analysis in this article finds the optimal plant mix will need to be increasingly 'flexible' to complement variable renewables.

1. Introduction

Australia's National Electricity Market (NEM) is an energy-only gross wholesale pool. The operation of an energy-only market is well documented by Simshauser (2010). For such a market to be sustainable it must facilitate an "optimal mix" of generators recovering their fixed (capacity) and variable (fuel and operating) costs over the business cycle. Early studies of the NEM concluded that it had produced significant economic benefits (see Parer, 2002, as an example) despite concerns about revenue adequacy for generators (Simshauser, 2010).

From 2001 onwards, Australian policymakers introduced a number of often overlapping policies aimed at reducing greenhouse gas emissions and increasing the penetration of renewable energy. These included: the Mandatory Renewable Energy Target (MRET); the Large Scale Renewable Energy Target; Premium Feed-in Tariffs (FiT) for embedded generation; the NSW Greenhouse Gas Abatement Scheme; the Clean Energy Act (carbon pricing); the 13% (subsequently 18%) Queensland Gas-Fired Electricity Generation Scheme; and various capital subsidies for solar hot water and embedded solar PV generation. Nelson et al. (2010) provide an overview of the various types of climate change and renewable energy policies that have been introduced over the preceding two decades.

These climate change and renewable energy policies facilitated enormous investment in new generation capacity. Nelson et al. (2015) found that around 16 GW of new investment has been facilitated by climate change policies in Australia. But aging "firm dispatchable" capacity has been withdrawn from the NEM in significant quantities. As low short-run marginal cost (SRMC) renewable plant reduced wholesale prices, aging and inflexible (but firm and dispatchable) coal-fired plants have been retired, resulting in a sudden and dramatic upward shift in wholesale electricity prices.

A relatively unexplored but critical shortcoming of energy-only markets in a "high penetration" renewables system is the interaction with forward derivative markets. In "restructured" markets with retail competition, a liquid forward market is critical to facilitate price risk mitigation. As an intermittent energy source, renewables (excluding hydro) are unable to sell financial derivative products to retailers. As renewable grid penetration increases, an increasing proportion of the load is traded without price risk mitigation products in place. These issues are becoming apparent in high-renewable-penetration markets such as South Australia.

A blackout in South Australia on Sept. 28, 2016, resulted in the Australian Government initiating an inquiry into energy policy, led by Australia's Chief Scientist (Finkel et al., 2016). The review provided 50 recommendations to government. Arguably the two most important recommendations were the introduction of a "Clean Energy Target" and a "Generator Reliability Obligation." These two obligations were thought to deliver on the objectives of reliability, affordability, and reduced greenhouse emissions by incentivizing investment in low-emissions electricity supply and ensuring that participants in the market supported the forward derivatives market to ensure reliable supply and liquidity that facilitates ongoing retail market competition.

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In late 2017, the Commonwealth Government ruled out implementing the Clean Energy Target and instead developed the "National Energy Guarantee." This policy is effectively a "baseline and credit" scheme which would incentivize electricity retailers to source low-emissions generation to meet an emissions baseline consistent with Australia's international obligations articulated at COP21 in 2015, a 26–28% reduction in emissions by 2030 relative to 2005 levels. At the same time, retailers would also be required to demonstrate support for "reliability" by adequately contracting for "firming generation." It is thought that such a policy could facilitate the ambitious targets of Victorian and Queensland state governments, where policies to achieve 40% and 50% renewable energy penetration, by 2025 and 2030, respectively, have been set.

In the middle of all this has been an intense political debate about the Liddell power station in New South Wales. The owner, AGL Energy, announced in 2015 that the 2000 MW coal-fired power station would close in 2022 as a result of both its age and its emissions profile being inconsistent with the Commonwealth Government's commitment to playing its part in keeping global warming limited to 2 ° Celsius (AGL, 2015, 2016). A number of Commonwealth Members of Parliament (MPs) have stated that AGL is "shorting the market" and that it should be "forced to keep the power station operating" (ABC, 2017). AGL has committed to developing a "90 day plan" for investment in new capacity and energy equivalent to that required to meet any gaps caused by the closure of the Liddell power station.

The purpose of this article is to consider the most appropriate investment for new supply side infrastructure in the Australian market given: changing demand dynamics; technology costs; and the need to reduce greenhouse gas emissions. Section 2 articulates the different market dynamics of the U.S. and Australia as they relate to closure of coal-fired power stations. An overview of the New South Wales electricity market and changing electricity demand and technology costs is presented in Section 3. An "optimal plant mix" solution is modeled in Section 4 with other important considerations for investors evaluated in Section 5. Concluding remarks are provided in Section 6.

2. Disorderly exit of coal-fired power stations: a contrast with the U.S.

Australia has experienced a "disorderly" transition to renewables as existing aging coal-fired power stations have been closed. Prices were significantly below long-run average cost for many years due to oversupply created by flat underlying energy demand and new supply of renewable energy driven by climate change policies. Eventually, the economic pressure of relatively low wholesale electricity prices led to the disorderly withdrawal of significant quantities of capacity.[1] The closure of capacity is shown in Table 1.

Importantly, very little notice of closure was provided by any of the power station owners. In the case of Hazelwood, Northern and Playford, less than one year of notice was given. Unsurprisingly, forward contract electricity prices increased substantially. With such little notice of closure, there was no time for new generation to be built. Importantly, "firm dispatchable" capacity is still required to complement the significant penetration of wind generation within the Victorian and South Australian regions. The total closure of thermal capacity and investment in new renewable and gas-fired infrastructure is presented in Table 2. It is clear that investment in new "firm dispatchable" capacity has not kept pace with capacity withdrawals of aging coal-fired power stations since 2013.

Table 1
Power station closures in National Electricity Market.
Source: AEMO data.

State	Power station	Coal type	Commissioned	Closed	Capacity (MW)
NSW	Munmorah	Black	1969	2012	600
NSW	Redbank	Black	2001	2014	143
NSW	Wallerawang C	Black	1976	2014	1000
VIC	Morwell	Brown	1958	2014	189
VIC	Angelsea	Brown	1969	2015	160
QLD	Collinsville	Black	1968	2012	180
QLD	Swanbank B	Black	1970	2012	500
SA	Northern	Brown	1985	2016	546
SA	Playford	Brown	1960	2016	240
VIC	Hazelwood	Brown	1964	2017	1600

Table 2
New capacity and coal-fired capacity withdrawals in Australia.
Source: Simshauser (2017).

Year of Exit/Entry	Coal Retirements		Gas Plant Entry			Renewables Entry	
	No. of plant	Capacity (MW)	No. of plant	Total (MW)	CCGT[a] (MW)	No. of plant	Capacity (MW)
2005–2012	2	740	31	8674	2546	112	2640
2013 +	9	4656	4	218	52	49	2422
Total	11	5396	35	8892	2598	161	5062
Av. Age		42 years					

Coal-fired generation closure – 18% of fleet.
[a] CCGT column is a subset of the total gas capacity column.

It is not unusual for coal-fired power stations to be permanently closed when they are at an advanced age. Fig. 1 shows the age of coal-fired power stations operating globally. Very few power stations are operating beyond 50 years of age. Australia's experience, whereby around three-quarters of the thermal fleet is beyond its original design life (Nelson et al., 2015), is not too dissimilar from other comparable markets.

As a contrasting example, in the U.S. there have been similar closures of aging coal-fired power stations. However, there are two critical differences between the U.S. and Australia: the relatively stable policy environment in the U.S.; and the price and availability of natural gas since the turn of the decade. Australian investors have been reluctant to invest in new mid-merit gas-fired generation (such as combined-cycle turbines) due to both an inherently uncertain long-term energy and climate change policy and the significant changes that have occurred in domestic gas markets.

Australia's east-coast gas market has changed materially over the past decade. The development of new drilling technologies led to a significant increase in reserves from around 3400 PJ in 2005 to around 50,000 PJ today. This resulted in the construction of three large LNG export facilities in Queensland. There is more than enough gas to *physically* satisfy domestic demand and current LNG export contracts for at least 20 years. But the estimated marginal cost of production for these resources is around \$6/GJ. Beyond around 50,000 PJ there is a significant step-change in estimated costs with a range of between \$7/GJ and \$9/GJ, reflected in Fig. 2. The same technological revolution that has unlocked low-cost shale gas resources in the U.S. has produced the perverse outcome in Australia whereby higher-cost gas resources (from coal-seam gas) set the marginal cost of gas utilized in gas-fired electricity generation infrastructure.

But in the U.S., access to low-cost shale gas has resulted in significant investments in new gas-fired capacity. The retirements of U.S.

[1] It is ironic that the 'merit-order effect' which has played a contributing role in the disorderly transition to renewables was at one time celebrated by some commentators as a way to permanently reduce prices. Felder (2011) demonstrated conclusively that in contrast to popular public perception, it is not welfare enhancing. Felder (2011, p. 34) sums up this apparent economic contradiction succinctly, '.if all electricity was provided by out-of-market technologies wholesale energy prices would be near zero, yet consumer electricity costs would increase to cover the additional costs of these technologies, thereby indicating that there was something amiss.' In other words, the 'merit-order effect' must be transitory in nature.