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Climate change policy discontinuity and its effects on Australia's National Electricity Market

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Abstract

Australia's National Electricity Market (NEM) became unstable in 2016/17 after 20 years of consistent performance. The South Australian grid collapsed on 28 September 2016 – Australia's first black system event since 1964. Wholesale prices in the region trebled to $120+/MWh; soon after Hazelwood power station announced its exit with just 5 months' notice. The problem spread as prices elsewhere doubled to $89/MWh from a long run average of $42.50. The NEM is experiencing a supply-side crisis. Consistent with the requirement to decarbonise the system, aged coal-fired generators are exiting but decades of climate change policy discontinuity has frustrated the entry of new plant. Long-dated capital-intensive asset industries like electricity supply anticipate a conventional policy cycle. What they have experienced instead is consistent with garbage can theory. Policy clarity may be emerging for only the second time in two decades. As with the NEM, its durability will depend on cooperative federalism.

Key words: climate change policy; policy uncertainty; garbage can theory

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1. Introduction

Australia's National Electricity Market (NEM) comprises the states of Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA), Tasmania and the Australian Capital Territory.[1] Although a national market, for clarity, it is a state-based national market – viz. state governments have constitutional responsibility for energy supply and the NEM Rules originate in the SA parliament with mirror legislation in all participating jurisdictions.

Although it commenced formally in 1998, the origins of the NEM date back to 1994; from then various member states progressively synchronised their state-based grids and state-based spot markets onto a single operating platform. From a design perspective, the NEM is classed as an "energy-only, gross pool electricity market" – generators are only paid when they produce (i.e. energy-only), and generators *must* sell all of their output to the single buyer (i.e. gross pool), viz. the Australian Energy Market Operator (AEMO). Energy retailers in turn purchase all of their customer load from AEMO.

The NEM is somewhat unique amongst the world's restructured electricity markets with its centrepiece being the single real-time platform. Every five minutes, a new spot electricity price is formed under a uniform first-price auction clearing mechanism[2], along with eight Frequency Control Ancillary Services spot market prices, with electricity production and frequency control services co-optimised across five imperfectly interconnected States/regions (MacGill 2010; Simshauser, 2017). AEMO coordinates all generators and bulk electrical loads in all regions and all spot markets, and again somewhat uniquely from a global perspective, without any formal day-ahead[3] or capacity market (Riesz et al. 2015). In addition to the NEM's organised spot markets, NEM participants trade in forward derivatives, both on-exchange (i.e. futures) and in the Over-The-Counter derivatives market, with swaps and options contract turnover or "liquidity" historically ranging from 300-450% of physical trade – meaning each Megawatt hour (MWh) will have been bought and sold between *3 - 4.5 times* before it has been delivered to customers.[4] Above all, the NEM has long been one of the world's top performing wholesale electricity markets and a model of microeconomic reform (IEA 2005; Simshauser 2014). Indeed as Price (2017) explains, apart from being a marvel of micro-economic reform, given state-based legislation underpins the entire system, it has also been a shining example of what can be achieved with cooperative federalism.

Yet during 2016/17 the NEM became unstable. In SA, electricity futures rose from $42/MWh in early-2015 to more than $120/MWh by mid-2016 and in September 2016 the entire SA regional grid collapsed – Australia's first "black system event" since 1964. From 2012-2017 more than 5000MW (18%) of coal plant had progressively exited the market, culminating in large baseload generators in SA and VIC (viz. Northern Power Station and Hazelwood Power Station, respectively). Following this, the problem spread beyond SA to the entire eastern seaboard. Electricity futures for 2018 delivery more than doubled to a weighted average of $89/MWh[5] (*cf.* long run average spot price of $42.50/MWh[6]).

[1] Western Australia and Northern Territory are too remote.

[2] In a uniform first-price auction, generator offers are ordered from lowest to highest, and the marginal offer accepted to satisfy aggregate electricity demand sets a "uniform price" for all dispatched generators (i.e. even though they offered a lower price).

[3] Although as MacGill (2010) points out, the Market Operator does produce a very transparent 40hr pre-dispatch forecast which is continuously updated.

[4] See Simshauser, Tian and Whish-Wilson (2015) and in particular Appendix III.

[5] In September 2017 electricity futures were $95 (NSW), $81 (QLD), $118 (SA) and $107 (VIC) with a NEM weighted average of $89/MWh.

[6] NEM weighted-average spot prices from FY2005-2017, expressed in constant 2017 dollars.

That this has occurred is extraordinary. Australia is among the world's largest exporters of coal, uranium and liquefied natural gas, and is endowed with some of the world's best quality renewable energy resources (Garnaut 2014; Byrne et al. 2013). The problem, however, is that while 5000+ MW or 18% of the coal-fired fleet exited the system, the timely entry of low emissions plant was frustrated – the product of two decades of climate change policy discontinuity.

Climate change policy does not, in theory, require cooperative federalism to function properly. In the Australian context it requires a coherent policy architecture to be set by the Commonwealth Government, the single entity responsible for determining nationally binding emission reduction targets. Such policy *architecture* would typically involve instruments such as carbon pricing and renewable targets.[7] But Australia has found the internalisation of CO_2 emissions (i.e. carbon pricing) exceedingly difficult to achieve at the national level due to strong partisan differences (Jones 2010; Byrnes et al. 2013; Jones 2014; Nelson 2015).

While centre-right and centre left members of parliament have sought to reach agreement, some powerful conservative members perceive carbon pricing damages low cost energy provided by fossil fuels. Further, renewable targets have historically required taxpayer funded subsidies to offset high upfront capital costs (MacGill 2010; Simshauser 2011). The political optics of subsidies can be difficult to navigate in a rising cost environment, particularly when the underlying objective is to drive out low-cost coal generators (Byrnes et al. 2013; Nelson et al. 2015; Jaraites et al. 2017).

Yet ironically for the NEM, the cost of inaction is proving greater. In a carbon price policy vacuum, 2018 electricity futures prices are trading at $89/MWh whereas spot prices averaged $58/MWh[8] during Australia's $23/t Carbon Tax period in 2012-2014. The reason for this apparent anomaly is utility and investor market expectation and investment conviction.

Australia committed to reduce greenhouse gas emissions by signing the Kyoto Protocol. More recently the Paris Agreement committed Australia to reducing emissions by 26-28% below 2005 by 2030. As with Kyoto, the Paris Agreement received bipartisan political commitment – a fact of which the energy utility investment community is well aware. However, significant uncertainty remains over the policy mix to achieve these reductions. Investors are rational and understand the power system needs to be progressively decarbonised over ensuing decades to meet the Paris Agreement. But power generating investments are among the most capital-intensive and long-lived of asset classes; each addition typically involves an investment commitment ranging from $250-$800 million, with terminal asset lives spanning 25-40 years. Consequently, the sheer quantum of shareholder equity and bank finance at risk means the dominant short-term investment strategy is to hold on to investment options; simply put, to do nothing and wait for policy clarity.

[7] The internalisation of carbon dioxide emissions through Emissions Trading Schemes occurs across a wide range of countries and jurisdictions. Nong and Siriwardana (2017) note this includes EU27 plus Switzerland, Iceland, Norway, New Zealand, South Korea and Kazakhstan. The US states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont also operate a carbon pricing scheme. California along with Québec and Ontario similarly have a joint scheme. China launched its ETS at the end of 2017.

[8] Expressed in constant 2017 dollars. Actual spot prices were $57.04 in 2013, and $51.44 in 2014.

This article reviews Australia's climate change policy discontinuity. It examines implications for the NEM and the potential for policy stability. It proceeds as follows. Section 2 briefly reviews Australian climate change policy. Section 3 presents analytical results which highlight practical implications of policy discontinuity, along with insights vis-à-vis future policy. Section 4 examines recent policy developments and Section 5 consolidates the article by contextualising policy development via garbage can theory, the theoretical underpinning of our analysis. Policy implications and concluding remarks follow.

2. Review of Australian Climate Change Policy

For most countries electricity production is a dominant source of CO_2 emissions and forms a central focus of climate change policy (Garnaut 2014; Bunn and Yusupov 2015). In Australia electricity accounts for more than one-third of CO_2 emissions (see Table 1) (Nelson 2015; Apergis and Lau 2015; Peters and Hertel 2017).

Table 1: Australian CO_2 emissions 2007-2017

Year Ending	Electricity Share	Electricity	Stationary Energy	Transport	Fugitive emissions	Industrial processes	Agriculture	Waste	Land Use	Total
(to March)	(%)	(Mt)	(Mt)	(Mt)	(Mt)	(Mt)	(Mt)	(Mt)	(Mt)	(Mt)
2007	33.7	205.5	81.9	84.0	41.1	33.9	72.1	14.1	76.4	609.0
2008	34.5	204.9	83.3	86.4	42.0	34.5	68.9	14.6	59.5	594.1
2009	35.5	210.7	85.2	87.5	41.6	33.6	68.3	14.6	52.8	594.3
2010	36.3	206.7	83.4	88.3	42.1	33.8	66.9	14.8	33.0	569.0
2011	35.7	198.7	85.5	90.3	42.0	36.1	70.0	14.5	19.9	557.0
2012	36.3	200.2	89.3	91.9	41.0	34.6	72.2	13.1	9.3	551.6
2013	35.5	189.1	92.2	92.2	42.2	32.5	72.6	12.0	0.2	533.0
2014	34.4	182.8	93.6	93.0	41.1	32.4	72.8	12.0	3.2	530.9
2015	34.8	186.4	91.9	94.8	43.3	32.3	70.7	11.5	4.7	535.6
2016	35.3	191.7	93.1	95.6	47.0	32.9	73.2	11.4	-1.1	543.8
2017	34.2	188.0	98.5	96.0	47.6	33.9	75.0	11.4	-0.2	550.2
Chg since '07		-8.5%	+20.3%	+14.3%	+15.8%	0%	+4%	-19.1%	-100.3%	-9.7%
Avg	35.1					Source: Department of the Environment & Heritage nent & Heritage				

Climate change policy aside, Australia's *underlying* electricity-related policies at the wholesale level have been stable, durable and world class (see EIA 2005; MacGill 2010; Simshauser 2014). Governance of the NEM is unique in that regulation, market operation and policymaking are aggressively separated.[9] But as Fleishman et al. (2014) explain a key dilemma for policymakers has been to achieve stable and durable, let alone united climate change policy architecture given strong political differences at the national level (Jones 2010; Nelson et al. 2013; Byrne et al. 2013; Wagner et al. 2015; Nelson et al. 2010; Simshauser 2014; Byrne et al. 2013; Molyneaux et al. 2013; Freebairn 2014; Garnaut 2014; Jones 2014; Nelson 2015; Apergis and Lau 2015).

Electricity sector policy options pursued by governments in response to international climate change commitments can be catalogued into four[10] broad streams:

[9] Regulation is undertaken by the Australian Energy Regulator. System operations is undertaken by the Australian Energy Market Operator. Rulemaking is undertaken by the Australian Energy Market Commission, who in turn is accountable to Energy Ministers.

[10] A multitude of other greenhouse gas schemes have existed in Australia. As Daly and Edis (2011) noted, from 1997 more than 300 emissions reduction programs (dominated by grant programs) were tried by the Commonwealth and State Governments and could be catalogued by market mechanisms, grants, rebates and energy efficiency schemes (as an aside, grant schemes were notoriously poor performing with less than 3% of projects reaching operations within 5 years, and less than 18% after 10 years, while rebates produced very little abatement also – see Daly and Edis 2011). Onifade (2016) provides a different category basis including direct and indirect policies, mandatory and voluntary policies, price-based and quantity-based policies, investment-focused and production focused policies, and market-based and central planning-based policies. Onifade (2016) also has a broader catalogue of instruments including tendering incentives, taxation incentives, R&D, PPPs, loan supports and government grants and regulatory standards.

1. Quota Obligations or Renewable Portfolio Standards such as Renewable Energy Targets levied on energy retailers (MacGill 2010; Onifad, 2016);
2. Carbon pricing such as a Carbon Tax or an Emissions Trading Scheme[11] levied on generators (Freebairn 2014; Garnaut 2014);
3. Contracts-for-Differences (CfDs), where a centrally-coordinating buyer undertake reverse auctions aimed at introducing cleaner technologies[12] funded by taxpayers or electricity consumers (Kozlov 2014; Wild 2017)[13]; and
4. Distributed Energy Resource (DER) policies, such as solar PV Feed-in Tariffs to encourage household adoption of distributed technologies (Nelson et al. 2011, Pollitt and Anaya 2016).

There is no consensus about the optimal mix of policy instruments. As Pollitt and Anaya (2016) and Onifade (2016) observe, most countries pursue various combinations. At different times Australian governments have initiated all policy instruments – although few, if any, in durable form (Jones 2009; Daly and Edis 2011; Garnaut 2014; Nelson 2015). Development of Australia's climate change policy can be traced back to 1997[14], the same year Australia signed the Kyoto Protocol[15] (Nelson et al 2010). At this stage, policy advice at the national level began to focus on two primary[16] market mechanisms: Renewable Energy Targets and Carbon Pricing (Jones 2009; MacGill 2010; Nelson et al 2010; Molyneaux et al 2013).

2.1 Renewable Energy Target

Australia introduced the world's first renewable energy portfolio standard, mandating an additional 2% of energy to be produced from renewable sources (MacGill 2010; Buckman and Diesendorf 2010; Forrest and MacGill, 2013; Cludius et al. 2014).[17] The policy was announced in 1997, legislated in 2000[18] and commenced in 2001 (Jones 2009; Nelson et al. 2013).

During the 1990s Australia's energy production was dominated by coal (85%) with hydro (10%) and gas (5%) forming the balance. Annual growth in energy demand was ca.2%

[11] A carbon tax fixes the price of CO_2. An ETS fixes the volume of CO_2 by way of 'Cap and Trade' or 'Baseline and Credit'. As Daly and Edis (2011) explain, market-based schemes like an ETS deliver greatest emissions reductions and do so ahead of time - the reason being they minimise need for governments to predict the outcomes, and maximise the flexibility in how objectives are achieved.

[12] That is, governments offering long-dated Power Purchase Agreements on behalf of consumers via a reverse auction process. See for example Wild (2017) for a detailed analysis of CfDs for solar PV capacity.

[13] Onifade (2016) observes that the UK's CfDs appears to be a hybrid policy that combines and improves on FiTs and Quota Obligations. See also Bunn and Yusupov (2015) for a different interpretation.

[14] The Howard Government released a broad climate policy strategy titled "Safeguarding the Future: Australia's Response to Climate Change. On 20 November 1997 Prime Minister Howard announced that the Commonwealth would work with the State Governments to "set a mandatory target for electricity retailers to source an additional two per cent of their electricity from renewable energy sources by 2010". In the same speech, the PM stated on emissions trading that "Australia also believes that an international emissions trading regime would help minimise costs of reducing emissions. We would support emissions trading on the basis of a satisfactory initial allocation of emission entitlements and a practical resolution of the administrative difficulties involved." (see Parliament of Australia at: http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query%3DId%3A%22chamber%2Fhansardr%2F1997-11-20%2F0016%22 – accessed August 2017).

[15] The Kyoto Protocol was held in Kyoto, Japan from 1-11 December 1997.

[16] The reason these form the primary focus is due to effectiveness. In a thorough study on the matter, Daly and Edis (2010) found market mechanisms consistently led to lower emission outcomes at consistently lower cost than predicted when policies were formulated (they examined Australia's RET, Qld's GEC, the NSW NGAS, the EU-ETS and two North American sulphur dioxide markets). Forecasts underestimated commercial innovation, and targets were inevitably easily achieved. Consequently, certificates would almost always fall below expectations (indeed, prices would often collapse). Their key conclusion was that markets, enabled by pollution pricing, deliver more emission cuts more cheaply.

[17] While Australia was the first country to introduce a Renewable Portfolio Standard mechanism, the concept was originally developed in the USA (see Buckman and Diesendorf 2010).

[18] The legislation giving effect to the RET is the *Renewable Energy (Electricity) Act (2000)*.

but key hydro resources were already developed. Left untouched, renewables (viz. hydroelectric and a trivial amount of wind generation) would form an ever-diminishing share of the energy mix (Simshauser 2011).

Australia's renewable portfolio standard became known as the 2% Mandated Renewable Energy Target or "MRET". The policy intent was to increase Australia's renewable power generation from 10% to 12% market share by 2010 (Byrne et al. 2013).[19] Rather than being expressed as an additional 2% market share, the MRET was expressed as a fixed volumetric target of "9500 GWh by 2010", primarily to give investors certainty over the level of capacity required (Nelson et al. 2010). Liability for meeting the target was placed on electricity retailers and mobilised by way of tradeable certificates (MacGill 2010).

Qualifying renewable generators could produce a Renewable Energy Certificate (REC) for each MWh they produced. Electricity retailers were allocated a set quantity of RECs to purchase each year (Cludius et al. 2014). Retailers tgat failed to meet their quota faced a penalty price of $40/REC (Jones, 2009). Because fines are not tax-deductible, the penalty had a tax-imputed value of $57/REC (Nelson et al. 2013).[20] When the policy was adopted in 1997, renewable projects were small-scale and expensive; meeting a 9500GWh target by 2010 was considered challenging.[21]

However, a review of the MRET in 2003 (Tambling Review)[22] found the target would be comfortably met four years ahead of schedule in 2006 (Buckman and Diesendorf 2010; Daly and Edis 2010). The cost of renewables was unambiguously higher than the cost of conventional energy sources; only policy intervention would drive further growth (Simshauser 2011). Without an expansion of the target additional investment was in renewables would cease from 2007 onwards (Cludius et al. 2014). The Howard Government rejected a Tambling Review recommendation to do so (Jones 2009).

With the stalling of renewable investments entirely predictable, VIC launched a state-based policy of '10% renewables'. NSW and SA made preparations to follow suit (Jones 2009; Nelson et al. 2013; Jones 2014). As Section 2.1 later reveals, QLD had already launched its own Clean Energy Target with 'technology set-asides' (see Schelly 2014) comprising a 13% Gas Electricity Certificate scheme and a 2% renewable target. The looming 2007 federal election produced two election policy commitments in response; the Rudd Labor opposition committed to a greatly expanded 20% Renewable Energy Target (RET) by 2020, while the incumbent Liberal Government committed to a technology neutral 15% Clean Energy Target (Jones 2010; Nelson et al. 2013; Apergis and Lau, 2015).

Following its 2007 election victory, the Rudd Labor Government moved quickly to legislate the 20% RET, which was passed in 2009 (Cludius et al. 2014).[23] The Clean Energy

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[19] ESAA Data from 1998 reveals that over the five-year period 1992-1996 Australia's renewable energy production averaged 15,940 GWh per annum, slightly above the 1997 baseline of 15,000 GWh.
[20] The opportunity cost of the MRET penalty incorporating the taxation rate of 30% was $57.14, i.e. ($40/0.7).
[21] The issue here was one of scale, or lack thereof. Most of Australia's hydroelectric sites had been developed in the 1950-1970s. Following the MRET, early projects lacked scale and were high cost. For example, the first wind farms were typically less than 20MW in size, produced perhaps 30GWh per annum, and had unit costs that were 2-3 times the cost of new entrant coal plants. However, over time the scale of projects increased dramatically thus enabling the target to be met well ahead of schedule.
[22] For details of the Tambling Review see http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query=Id%3A%22library%2Flcatalog%2F00122747%22
[23] The legislation was the Renewable Energy (Electricity) Amendment Act 2009. Around the same time, the Renewable Energy Directive (mandating the EU15 achieve 20% renewable energy production by 2020) also entered into force (see Jaraite et al. 2017).

Target policy was, of course, discarded. The RET was expressed as an additional 45,000 GWh by 2020 and the ceiling price raised to $65/REC which had a tax-effective value of $92/REC. However, the RET contained a number of contentious design issues, and serious design flaws.

Particularly contentious was the lack of technology diversity or *technology set-asides* (Byrne et al. 2013[24]). Another was the absence of an in-built mechanism to reduce incentives over time (Buckman and Diesendorf 2010). The differential treatment of 'Energy Intensive Trade Exposed' (EITE) industries was also controversial (Jones, 2010). Industries such as aluminium, zinc, iron, steel, petroleum refining and newsprint received a 90% exemption from the RET certificate costs, while moderate emissions-intensive industries such as wood, paper, glass and certain chemical processes received 60% exemptions (Byrnes et al. 2013; Cludius et al. 2014). This meant a greater burden would be placed on non-EITE customers, viz. small business and households (Buckman and Diesendorf, 2010). Consequently, any merit-order effects[25] arising from renewable plant entry would benefit EITE firms disproportionately (Forrest and MacGill 2013; Bell et al. 2015).

The importance placed on output over power system stability proved a key design flaw. Qualifying facilities received a certificate for each MWh produced – notionally $65/REC. Thus renewable generators were incentivised to maximise output regardless of power system conditions. As Bunn and Yusupov (2015) explain, whenever spot electricity prices fall to negative levels[26], indicating an over-supplied market and that power station "unloading" is required, renewable generators continue to generate and make a gross profit until clearing prices fall below -$65/MWh. Additionally, little thought went into the provision of Frequency Control Ancillary Services (i.e. services provided by generators to ensure a good quality of supply) and consequently, no Variable Renewable Energy (VRE) plant in Australia to this day provides any form of system stability service (MacGill 2010).

But these design errors paled into insignificance by comparison to (1) the last-minute inclusion of a two-yearly statutory review, ironically negotiated by the Greens; and (2) the inclusion of the 'solar credits multiplier' (Buckman and Diesendorf 2010; Jones 2010; Nelson et al. 2011; Byrne et al. 2013; Nelson et al. 2013; Cludius et al. 2014).

1. Two-yearly statutory reviews of the RET were an unambiguous disaster. As each review drew closer, an *investment blackout* was predictable due to the risk of policy change. Such risk was more than theoretical. The RET policy has been the subject of six formal reviews and fundamentally changed on three occasions. Unsurprisingly, renewables experienced short sharp investment bursts punctuated by an investment freeze for the duration of any review.
2. A 'solar credits multiplier' aimed to provide additional incentives to small-scale rooftop solar PV systems in addition to an upfront 'deeming' process, whereby rooftop solar PV systems would be granted certificates equivalent to 15 years of

[24] As Byrne et al (2013) note, with one REC for each MWh produced, the RET favoured lowest cost production such as wind and hydro.
[25] Forrest and MacGill (2013) found that entry of wind generation was placing downward pressure on wholesale prices, offsetting the higher costs of gas, and significantly reducing the output of brown coal generation especially in SA. Their static estimate of the Merit Order Effect in SA-VIC as a joint region was -$4.28/MWh. Cludius et al. (2014) estimated -$2.30/MWh merit-order effect in 2011-12 (REC costs of +$3.38/MWh) and -$3.29/MWh merit-order effect in 2012-13 (REC costs of $5.29/MWh). Consequently EITE industries were better off by $1-$2/MWh depending on whether they had a 90% or 60% exemption. Residential and SME customers were estimated to be $1-$2 worse off. See also Bell et al. (2015) and Bell et al. (2017) for various assessments of the merit-order effect flowing from wind investments. Felder (2011) provides a very thorough theoretical analysis of the merit-order effect and its dynamic endurance. See also Nelson et al. (2012).
[26] Bunn and Yusupov (2015) note negative prices occur in Australia, North America, Germany, Denmark and Spain.

future output upfront (i.e. upon installation of the system, to reduce transaction costs). Starting with a '5x' solar credit multiplier, a rooftop solar PV unit would receive RECs equivalent 75 years of future production (i.e. 5 x 15 years of deemed future output) in the year of installation (Nelson et al. 2013). The sheer size of the subsidy, coupled with state-based feed-in tariffs, created boom conditions for the small-scale technology. But because certificates were created and traded up-front, these so-called *Phantom Renewable Certificates*[27] completely overwhelmed supply and destabilised the RET policy (Buckman and Diesendorf 2010; Jones 2010; Byrne et al. 2013; Cludius et al. 2014). The market was flooded with rooftop PV certificates at a ratio of 1:75 (i.e. 1 year of small-scale solar PV production output, 75 years of certificates) which led to a REC price collapse as Figure 1 indicates (Nelson et al. 2013). Because spot electricity prices were also low at the time, without intervention the RET would fail to meet its policy objective because the two income streams (i.e. spot electricity revenues and REC revenues) were insufficient to justify new utility-scale renewable plant investments.

The *Phantom REC* design error was so serious that the policy was reviewed, and substantially amended, for the second time. In June 2010, the 45,000GWh RET was split into a Large-Scale Renewable Energy Target (RET) with a new target of 41,000GWh, and Small-Scale Renewable Energy Scheme (SRES) with a notional, but uncapped, target of 4000GWh thus totalling 45000GWh (Nelson et al. 2013; Byrne et al. 2013; Cludius et al. 2014; Nelson 2015).[28] This had the effect of annexing rooftop solar PV from the utility-scale market with the solar multiplier (responsible for creating Phantom RECs) rapidly phased-out. For the Large-Scale RET, the REC[29] trading range continued up to $92/REC while the SRES had a fixed certificate price of $40 and were relabelled Small-Scale Technology Certificates or STCs.

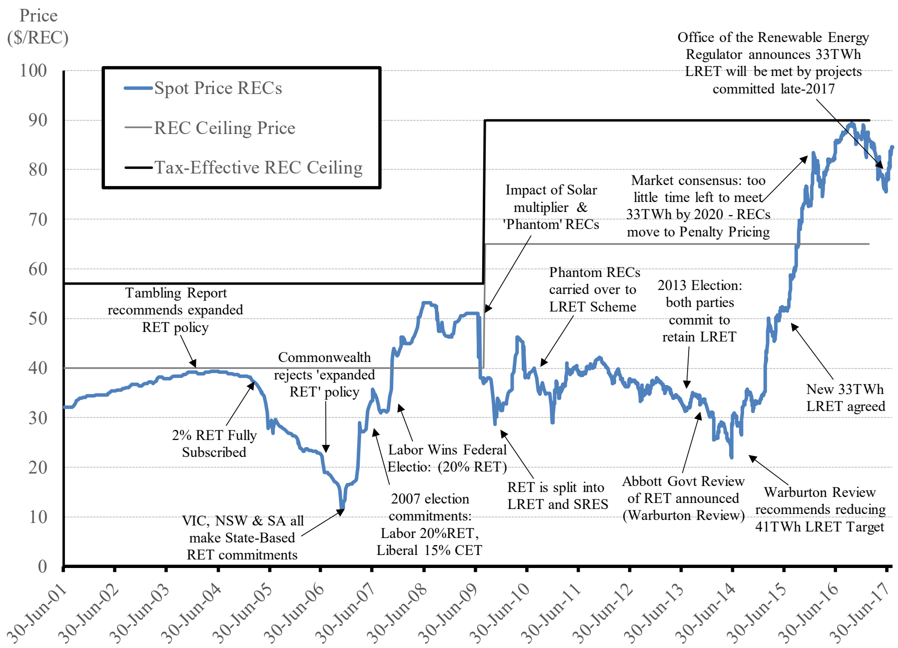
In 2013 the incoming Abbott Government commissioned yet another fundamental review of the RET ('Warburton Review'). While the problem of Phantom RECs had been largely dealt with, a new problem was emerging – the policy decision to fix the target at 41000 GWh rather than express the target as 20% of demand. After 118 years of continuous growth, final electricity demand began to contract following the global financial crisis, years of above-CPI electricity price increases and new behind the customer meter technologies, viz. solar PV and energy efficient appliances. With the RET fixed at 41,000GWh, the 20% target was beginning to look much closer to 25-30% (Byrne et al. 2013). Consequently, the basic narrative surrounding the Warburton Review was that the fixed target was overwhelming an increasingly unstable wholesale electricity market. Indeed, on the one hand, the expanded RET involved the rapid expansion of wind generation which had a downward effect on wholesale prices (Garnaut 2014; Bell et al. 2015). However, on the other hand, the RET contributed to price increases via the REC certificate costs levied at the retail level. These costs came into sharp focus at a time when retail tariffs were increasing sharply, albeit mainly via rising network charges. Ultimately, after protracted negotiations with the Renewables Industry and the Labor opposition, the RET was scaled-back to 33000GWh in mid-2015.

Years of RET policy discontinuity had cruelled renewables investment during the 2013-2015 period, and thus by the time the revised 33000GWh target was finally settled there was limited time left to build the capacity required to meet the 2020 target. Most analysts

[27] The RECs acquired the term 'Phantom' because, using the 3kW system example above, of the 328.5 RECs created only 4.4MWh of renewable energy would be produced in the year the RECs were issued.
[28] Having split schemes, or "set asides" for small scale renewables, is common in the USA (see Schelly 2014).
[29] RECs were re-labelled Large-Scale renewable Generation Certificates or LGCs.

predicted adequate capacity would not be built until 2023-2024. REC prices quickly moved to the top end of the credible trading range, as Figure 1 illustrates.[30]

Figure 1: REC Spot Prices (2001-2017)



Source: Nelson et al. (2013), BNEF.

Figure 1 illustrates that politics affects prices as much, if not more so, than industry fundamentals (Buckman and Diesendorf 2010; Nelson et al. 2013; Cludius et al. 2014; Nelson et al. 2015). Notice the REC price surge towards the ceiling price of $92/REC during 2015-2017. However, with sharp increases in NEM wholesale prices throughout 2016/17 and RECs at the top of their trading range, renewable energy project commitments ballooned to record levels. Perhaps the most extraordinary aspect of the RET has been its success despite the discontinuities of policymaking processes. The private sector's continued investment in the scheme remains an enduring mystery. By mid-2017, the Renewable Energy Regulator announced that sufficient renewable projects would be sanctioned by year-end to meet the 2020 target. For all intents and purposes, the RET will be closed to new entrants from 2018 onwards.

2.2 Carbon Pricing

As with the RET, carbon pricing policy development also commenced in 1997 with the (then) Australian Greenhouse Office (AGO) initiating a public consultation process spearheaded by a series of well-researched 'Discussion Papers' on an Emissions Trading Scheme (AGO 1999a; 1999b).[31] The energy sector was actively engaged in the process led by the AGO, which culminated in a recommendation to Cabinet to initiate an Australian 'Cap and Trade' Emissions Trading Scheme (ETS). But sponsoring Ministers evidently misjudged Prime Minister Howard's appetite for internalising CO_2 emissions. The ETS was discarded well before it moved to legislative drafting. At its core, an ETS would

[30] Jaraite et al. (2017) examine the macroeconomic impacts of VRE investment by focusing on capacity rather than energy, and find that in the short run the gross effect of increasing investments in renewable energy sources on economic activity and employment are *obviously positive*, but surprisingly, in the long run increases in wind and solar capacity are associated with negative economic growth at the total economy level.

[31] In fact there were four Discussion Papers issued by the AGO but the two listed in the References formed the basis of the fundamental ETS debate in Australia at the time.

impose an environmental tax on CO_2 emissions and adversely affect Australia's low-cost energy which existed courtesy of a vast fleet of coal-fired power stations.

A visible trend in Australian climate change policy has been the willingness of state governments to initiate their own schemes when the Commonwealth has failed to provide credible policy to match international commitments – as has been the case in the USA and Canada (Jones 2009; Nelson et al. 2010; Schelly 2014; Jones 2014).[32] As Section 2.1 explained, QLD introduced a 15% Clean Energy Target with technology set-asides (13% gas, 2% renewables) and in January 2003, NSW introduced the world's first CO_2 baseline and credit ETS[33] (Jones 2009; Nelson 2015). As Daly and Edis (2010) would later note, both schemes were highly successful in that targets were exceeded faster than expected and at considerably lower cost than any market forecast.

By 2004, the Commonwealth government had not progressed any further with carbon pricing. However, sub-national governments had progressively switched to Labor. Collectively, Labor State Premiers agreed to pursue a state-based national ETS (Jones 2014). This culminated in the 2006 "National Emissions Trading Taskforce" report (NETT 2006). As Nelson et al (2010, p.446) explain, the state-based ETS was *'born out of inaction by the Federal Government'*. It soon became clear to industry that the "NETT policy" needed to be taken seriously.

In response, Prime Minister Howard established an ETS Taskforce[34] in late-2006 which reported in May 2007 (Nelson et al. 2010). This was a critical juncture because the recommendation, to implement a 'Cap and Trade' ETS, was accepted. The Kevin Rudd led Labor opposition had an identical policy platform, largely informed by the work of his state counterparts (Jones 2010). After a decade of policy uncertainty, by mid-2007 a central tenet of climate change policy, carbon pricing, had achieved bipartisan alignment (Garnaut 2014; Nelson 2015). Simultaneously, the *National Greenhouse Gas and Energy Reporting Act* (2007) came into effect obliging all entities to report their CO_2 emissions annually (Nelson et al. 2010). The conditions necessary to produce a durable carbon pricing regime appeared to exist.

Labor won the 2007 federal election. Among the Rudd government's first actions was to ratify the 1997 Kyoto Protocol signed 10 years earlier. With a commitment to introduce an ETS by 2010, 2008-2009 followed a conventional policy cycle, including design, consultation and drafting of relevant legislation for a Cap and Trade ETS (Buckman and Diesendorf 2010).[35] *Because* a credible national climate change policy was now well advanced, NSW and QLD moved to close their respective state-based schemes to avoid duplication and overlap.

Design of the Commonwealth's ETS was credible and comprehensive as Freebairn (2014) explains. The ETS covered 60% of national economic activity; draft legislation

[32] As Schelly (2014) notes, there is no national climate policy in the US per se and consequently States have taken a leadership role. Schelly (2014) notes that more than half of the US state have a Renewable Portfolio Standard although ironically, no two schemes are alike. Peters and Hertel (2017) note that in August 2015 the US Environmental Protection Agency announced the Clean Power Plan to reduce CO2 emissions by 32% below 2005 levels by 2030 – but they also note Business As Usual is likely to achieve this target.
[33] The NSW 'Baseline and Credit' mechanism was organised with electricity retailers being the liable party and subjected to a gradually declining 'CO_2 per capita' target. Although a NSW scheme, it was open beyond the borders of NSW and extended to any facility connected to the National Electricity Market. More than 130 CO_2-emitting facilities qualified and abatement of 73mt was achieved prior to scheme closure in 2010. See Nelson et al. (2010) for further details.
[34] Known as the Prime Minister's Task Group on Emissions Trading or "PMTGET". See PMTGET (2007).
[35] The 'Cap and Trade' ETS was known as the Carbon Pollution Reduction Scheme (CPRS). The policy process included a Green Paper in 2008 and White Paper in 2009. See Nelson et al. (2010).

incorporated a commitment to reduce CO_2 emissions by 5-15% below Year 2000 levels by 2020. Legislation was introduced to parliament in May 2009, but was initially voted down in the Senate – somewhat ironically by the Greens in what would subsequently prove to be a catastrophic error of political judgement. Had this package succeeded, there is little doubt in our minds that Australia would have adopted an ETS.

The ETS legislation was modified and reintroduced into parliament in October 2009, but in a dramatic turn of events the opposition Liberal Party changed leaders, from the pro-ETS Malcolm Turnbull to anti-ETS Tony Abbott on 1 December 2009. Bipartisan support for an ETS was lost (Nelson 2015). The leadership change was grounded in an anti-carbon pricing narrative and once again the ETS legislation was voted down. Amended legislation was introduced for a third time in February 2010, but the political environment surrounding an ETS had become so toxic that soon after, the Rudd Government pulled the amended legislation and announced any Carbon Pricing policy would be delayed until at least 2013 (Jones 2014). The policy was effectively discarded. As Nelson et al. (2010, p. 447) observed at the time, *'by any reasonable analysis industry certainty had been wound back to the same position it had been in just prior to 2006'.* This was a generous assessment. Industry was no closer to an ETS than it had been in 1997.

Prime Minister Rudd lost the leadership to Deputy PM Julia Gillard, in no small part due to Carbon Pricing policy discontinuity. Yet the new Prime Minister, faced with an aggressive anti-ETS campaign by the opposition leader, also recoiled from Carbon Pricing policy in the lead-up to the 2010 election.[36] The election result was considerably closer than expected and in order to form government, Prime Minister Gillard negotiated a revival of an ETS with the Greens. An ETS was legislated in 2011 and the scheme commenced from 1 July 2012 – initially as a fixed price Carbon Tax of A$23/t for a three-year period, before transitioning to a conventional Cap and Trade scheme from 1 July 2015 (Garnaut, 2014).[37]

As Freebairn (2014) notes, at one level Carbon Pricing would produce windfall taxation gains to government ($23/t x 550mt[38] pa x 60% coverage = $7.5bn). However, nearly half was recycled to low- and middle-income households via increases in social security and lower average taxation rates – justified by reasons of equity (Wild et al. 2015). Additionally, coal generators were offered structural adjustment assistance as were Energy Intensive Trade Exposed industrial electricity customers via allocated CO_2 price exemptions for 60-90% of their imputed liability based on the RET design parameters (Byrne et al. 2013). The net effects to macroeconomic outcomes were minimal because windfall taxation gains were recycled to retain the initial fiscal balance (Freebairn 2014).

However, the timing of the $23/t fixed price made the ETS scheme politically vulnerable. In prior periods, European Union emission permits had traded as high as €30/t, but by the time Australia's fixed CO_2 price was rolled-out, EU permits had crashed to €6/t (A$8.60/t) due to economic conditions following the GFC. With such a stark differential in the price of CO_2 emissions ($23/t vs $8.60/t) opposition leader Tony Abbott campaigned vociferously against carbon pricing and won the 2013 election on a platform to abolish the '*great big new tax'* on electricity.[39] ETS policy was discarded for a third time, albeit after two years of

[36] Prime Minister Gillard's now famous quote on 16 August 2010 was '*there will be no carbon tax under a government I lead'.* See http://www.smh.com.au//breaking-news-national/pm-says-no-carbon-tax-under-her-govt-20100816-126ru.html for details.
[37] See in particular Gillard et al. (2011).
[38] See Table 1.
[39] See http://www.theaustralian.com.au/news/tony-abbotts-next-policy-vow-anything-but-a-great-big-new-tax/news-story/c9d5786c7c87fb30e0af4ed3fc2d1ed1

operational experience. It would be replaced with a 'Direct Action Plan' (Apergis and Lau 2015).

The Liberal Party abandoned a market-based ETS mechanism for a tax-payer funded subsidy scheme with forward commitments in 2014-15 of A$2.55 billion (Nong and Siriwardana 2017). The politics of climate policy remained volatile, but Australia's international climate change commitments remained constant. Both major parties agreed to reduce emissions by 5% below 2000 levels by 2020 (Freebairn 2014). Under the Direct Action Plan the Commonwealth ran two reverse auctions[40] in 2015 to purchase CO_2 emission abatement consistent with Australia's commitments. As Nong and Siriwardana (2017) explain, 543 projects registered and 120 contracts were awarded covering many sectors of the economy. In total, the auctions secured 92Mt of CO_2 abatement for an aggregate cost of $1.217 billion, at average prices of $13.95/t and 12.25/t, respectively.

The Direct Action Policy was making tentative progress towards Australia's 2020 targets.[41] But the existing framework was not credible for targets beyond 2020; it would produce an ever growing need for taxpayer-funded subsidies under conditions of fiscal constraint. Policy durability collapsed when in 2015, Australia signed a new (and bipartisan) international agreement to reduce emissions by 26-28% below 2005 levels by 2030 at the Paris Conference of the Parties.

By late-2016, two decades of climate change policy discontinuity finally took its toll on the NEM's supply-side, with the exit of more than 5000MW of coal plant, inadequate entry and as noted in Section 1, rapidly rising prices and the collapse of the SA power grid. Discontinuity was a central cause of NEM instability. Both the RET and the Direct Action Plan had policy horizons of 2020, whereas the Paris 2030 target was a bipartisan commitment. A complicating factor was that various pockets of policymakers expressed support for different carbon pricing mechanisms, while others were simultaneously advocating for policy intervention to underwrite new coal-fired plant – diametrically opposing policies. Two policy initiatives emerged to resolve the impasse; the Finkel Review of the NEM, and the Commonwealth Government's Climate Change Policy Review – the latter to be completed during 2017 with the 2030 emissions target in mind. But before examining these two Reviews, it is helpful to review plant entry and exit statistics, and the cost curves of the rival technologies to provide necessary context.

3. Quantitative analysis

Plant exit and entry patterns in the NEM reveal the implications of two decades of climate change policy discontinuity. Comparative analysis with USA generation plant exit and entry decisions (Table 2) and an analysis of cost curves for the rival technologies (Figures 2–3) help to highlight key issues facing NEM policymakers.

Section 1 showed that more than 5000MW or 18% of Australia's coal-fired fleet has exited the market. As Table 2 highlights, in the US more than 60,000MW of coal-fired generation plant has exited its power systems – coincidentally also 18% of the US coal-fired fleet. Like Australia, the US lacks a unifying climate change policy framework at the national level – although unlike Australia, the US does exhibit climate change policy stability at the

[40] The reverse auctions were run in April and November 2015. With a reverse auction, there is a central auctioneer/buyer and multiple bidders and the auctioneer picks from lowest to highest in accumulating multi-unit quantities. The auction is constructed under a sealed bid format. In this instance, the Clean Energy Regulator was the buyer and set a unique price for each auction, with that price not being disclosed. All bids above the unique benchmark were automatically excluded. The Clean Energy Regulator would then purchase between 50-100% of bids below benchmark. For further details see Nong and Siriwardana (2017).

[41] Total CO_2 emissions abatement of 236Mt is required.

sub-national level, particularly in jurisdictions such as California and Texas. And in the US as coal plant exits, CO_2 emissions are falling *and* electricity prices have remained low and stable. Table 2 illustrates that the key difference is replacement of exiting coal plant in the US by an enormous fleet of wind, solar and gas-fired plant.

Table 2: US and Australian entry/exit ratios 2005-2017

	US Coal Plant	Capacity (MW)	US Gas-Fired Plant	Capacity (MW)	US Non-Hydro Renewables Plant	Capacity (MW)
1	Installed	286,721	Installed	511,558	Installed	117,231
2	Exit	61,624	Entry	117,958	Entry	102,447
3	Exit (%)	18%	Entry (%)	23%	Entry (%)	87%
4			Gas Entry Ratio	**1.9x**	Renewables Entry Ratio	**1.7x**
5			CCGT Entry (subset)	87,416	Wind Entry (subset)	89,089
6			CCGT Entry Ratio	1.4x	Wind Entry Ratio	1.4x
	Aust. Coal Plant	Capacity (MW)	Aust. Gas-Fired Plant	Capacity (MW)	Aust. Non-Hydro Renewables Plant	Capacity (MW)
7	Installed	24,436	Installed	18,697	Installed	6,511
8	Exit	5,396	Entry	8,892	Entry	5,062
9	Exit (%)	18%	Entry (%)	48%	Entry (%)	78%
10			Gas Entry Ratio	**1.6x**	Renewables Entry Ratio	**0.9x**
11			CCGT Entry (subset)	2,598	Wind Entry (subset)	4,553
12			CCGT Entry Ratio	0.5x	Wind Entry Ratio	0.8x

Source: US EIA, esaa, BNEF

The top segment of Table 2 provides installed coal, gas and non-hydro renewable plant capacity in the US (see line 1). Coal exit, gas-fired entry and non-hydro renewable plant entry follows (see line 2). An entry ratio is then displayed (see line 4) which calculates the gas-fired and renewable generation plant entry compared to coal plant exit. Notice from Table 2 that in the US 18% of coal plant exited (line 3), but the Gas Entry Ratio is 1.9 times (line 4) and Renewables Entry Ratio is 1.7x (line 4). That is, each MW of coal that has exited the US, has been replaced by 1.9MW of gas plant and 1.7MW of renewables plant. Line 6 also notes that of the Gas Entry Ratio of 1.9x is comprised of 1.4x semi-baseload CCGT plant (the balance being peaking plant). CCGT plant have a distinct "energy production bias" (as distinct from peaking plant which only produce in temperature-driven peak period events). The equivalent results for Australia are displayed at the bottom of Table 2 and are a stark contrast – semi-baseload CCGT plant entry (0.5x) being about 1/3 of the US result, and Renewables entry (0.9x) about ½ the US result.

The US data is not intended to represent some form of optimal benchmark; but that both countries have had virtually identical episodes of coal plant exit. Australia's power system has entered a crisis while the US has not, and this provides certain clues as to what should be happening vis-à-vis equipment replacement. Australia lacks a credible, durable and united climate change policy architecture, at any level of government, and this in turn had frustrated plant entry.

Analysis of the evolution of plant average cost curves over the past decade for the various new entrant technologies also provides important insights for policymakers. This is presented in Figure 2 and is based on PF Model results. The PF Model and associated inputs used to produce Figures 2 and 3 are outlined in Appendix I.

In Figure 2, three distinct entry timeframes have been presented (i.e. 2007, 2012 and 2017) along with four relevant new entrant technologies viz. solar PV, wind, CCGT and coal-fired generation plant. The x-axis measures annual plant capacity factor (% per annum) and the y-axis measures average unit cost ($/MWh) including a normal profit to capital providers. Coal and gas plant cost curves do not include the internalisation of CO_2 emissions; however, solar PV and wind cost curves do not account for intermittency.

There are four key points to note from these results. First, after rising initially, the cost of wind generation has fallen materially over the past five years on a unit cost basis. Australian results are consistent with unit cost reductions in the US (see Jaraite et al. 2017; Wiser and Bolinger 2017). Second, CCGT plant costs have risen dramatically. This is the result of sharp increases in the cost of natural gas following excessive LNG investments and constraints on the supply-side (see Garnaut 2014; Simshauser and Nelson 2015). Third, the unit cost of solar is changing rapidly, starting from "off the page" (quite literally) utility-scale solar PV is falling and will continue to do so. Finally, coal-fired plant is rising in cost; the cost of raw coal is a minor contributor – the main driver is the sharp increase in upfront capital construction costs driven by associated upgrades in technology in order to reduce (albeit marginally) CO_2 emissions, viz. from Super Critical pulverised fuel (SCpf) plant (in 2007, 2012) to Ultra Super Critical pulverised fuel (USCpf) plant in 2017. Indeed, as Appendix I notes, coal plant construction costs were $1500/kW in 2007 and are now estimated to be $3000/kW. Also worth noting is that the cost of capital (i.e. equity and bank finance) has fallen for renewable projects whereas non-renewable projects have not.

Figure 2: Evolution of entry costs 2007-2017

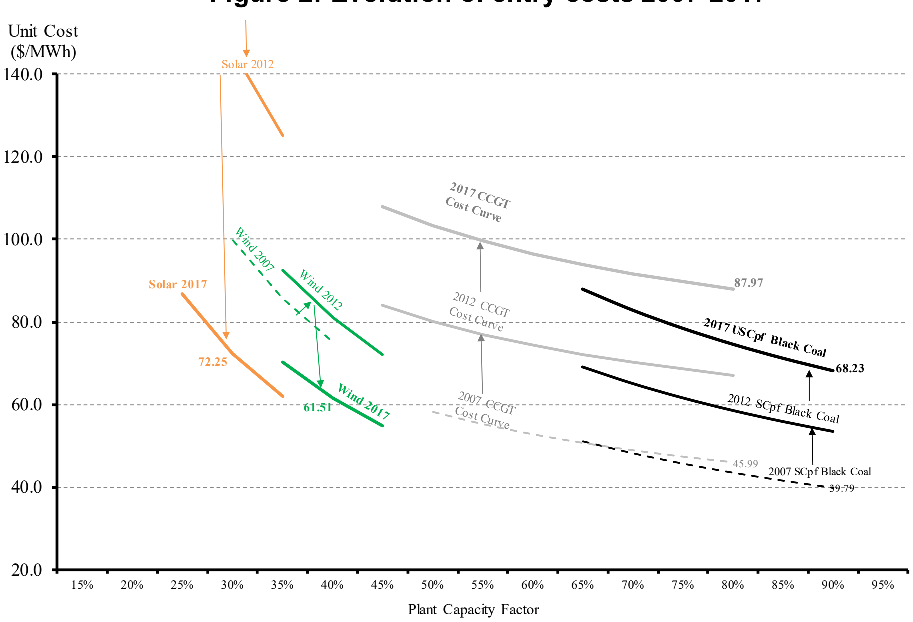
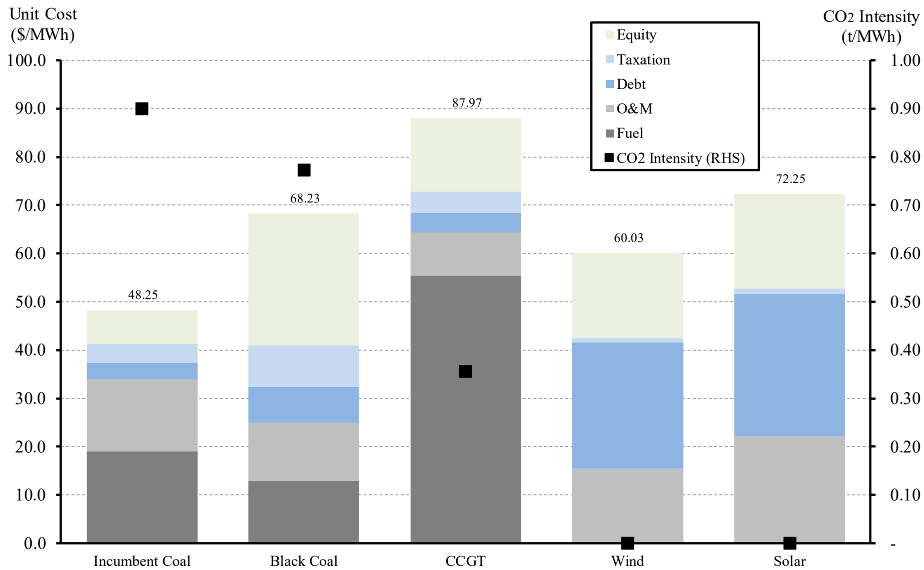


Figure 3 presents PF model results whereby incumbent coal plant is compared with the four new entrant technologies from Figure 2. These results help to reconcile two aspects of disparate policymaker views; (1) incumbent coal plant is the lowest cost form of generation – CO_2 emissions aside, and (2) wind generation is the lowest cost entrant – variability aside. But for clarity, new entrant coal plant is not.

Figure 3: Static 2017 new entrant costs vs incumbent black coal plant



In summary, coal plant is exiting the NEM at the same rate as it is exiting in the US. The entry of renewable plant into the NEM has been half the rate (i.e. 0.9x coal exit vs the US result of 1.7x). The policy discontinuity outlined in Section 2 explains why this is so. Concomitantly, gas-fired generation plant has failed to enter the NEM because, as Figures 2 and 3 illustrate, their cost has risen dramatically due to gyrations in the market for natural gas. Finally, new coal plant is an
expensive form of generation and the CO_2 intensity of such plant is more than double a CCGT gas-fired plant (see Figure 3). Incumbent coal plant remains the lowest cost form of generation – CO_2 emissions aside.

4. Finkel Review and the Commonwealth's 2017 Climate Change Policy Review

In early 2016, spurred on by an emerging supply-side energy crisis, the SA Government along with economics advisory firm Frontier Economics, began to pursue broad support for carbon pricing in the form of an Emissions Intensity Scheme ("EIS").[42] The EIS had the advantage of being electricity-sector specific, and due to its design, had a relatively benign effect on wholesale prices with most of the wealth transfers occurring gradually and progressively amongst high- and low-emission generators. Over the course of 2016, state governments, generators, retailers, industry groups and energy consumer groups began to form a unified position around the EIS policy proposal.

Power system conditions in SA continued to deteriorate, culminating in the collapse of the entire grid on 28 September 2016.[43] Weeks later, adding to deteriorating NEM conditions

[42] Managing Director of Frontier Economics, Danny Price, was the scheme's architect. Under a Baseline and Credit ETS, each generator is assigned a unique 'Baseline' level of emissions (e.g. 0.9t per MWh of output). If the generator is able to reduce its emissions intensity, then the firm can create certificates which can in turn be acquired by liable parties. Verification of improved performance forms part of the policy and associated regulations. Under the Emissions Intensity Scheme, a uniform CO2 intensity (e.g. 0.6t per MWh) is declared by policymakers, and any generator with lower emissions (e.g. renewables or efficient Combined Cycle Gas Turbines) can create certificates, and those generators with higher emissions (e.g. Coal, Open Cycle Gas Turbines) would need to purchase certificates.
[43] A real-time analysis of operating conditions revealed a critical weather event, a series of control system errors, a progressively weakening system due to the sheer volume of VRE plant and sub-optimal dispatch configuration. AEMO produced a detailed report at https://www.aemo.com.au/Media-Centre/AEMO-publishes-final-report-into-the-South-Australian-state-wide-power-outage (Accessed August 2017).

came the announcement that the 1600MW baseload Hazelwood Power Station (VIC) would close just five months later, in April 2017.

At one level, the power industry was evolving as it should; coal plant was exiting the system with CO_2 emissions declining as Table 1 noted. But at another level, the power industry was becoming increasingly dysfunctional because the entry of lower emissions generation plant had been frustrated as noted above. Indeed, VRE plant entry (viz. wind and solar) had stalled throughout 2014-2016 due to RET policy discontinuity, while cleaner-burning flexible gas-fired generation plant was not entering at all. On the contrary, semi-baseload CCGT plant was being withdrawn due to critical conditions in the gas market (Forrest and MacGill 2013; Bell et al. 2015; Simshauser and Nelson 2015; Apergis and Lau 2015; Bell et al. 2017). The anatomy of the unfolding energy crisis can be traced back to climate change policy discontinuity a decade earlier.

In response, the Commonwealth government sought to initiate a review of the NEM in October 2016 to be led by Australia's Chief Scientist, Dr Alan Finkel ("Finkel Review"). The purpose of the Review, later sanctioned by the COAG Energy Council, was to examine how the NEM might best "adjust" to the changing generation plant mix. Key to this was prescribing a stable and durable climate change policy architecture, and policies designed to deal with the reliability of generation plant supply in the context of rising intermittent renewable resources being deployed. Almost simultaneously but separately, the Commonwealth released its long-awaited Terms of Reference for its 2017 Climate Change Policy Review ("CCP Review") in December 2016.

In an interview with the Australian Broadcasting Corporation, the Commonwealth Minister for Energy flagged the prospect of the Emissions Intensity Scheme being considered as a possible policy option within the context of the CCP Review.[44] However, within hours, a Liberal Party backbench revolt led to direct intervention by the Prime Minister. The EIS policy option was killed-off before the CCP Review had even commenced. The Energy Minister confirmed as much by way of media release to *The Australian* newspaper 24 hours later.

The Finkel Review was left in the awkward position whereby the core problem to be solved, climate change policy discontinuity, and the industry consensus policy option, an Emissions Intensity Scheme, had been politically discarded. It proceeded by recovering the 2007 Howard Government election commitment, the Clean Energy Target policy. In contrast to the EIS, it emphasised no punitive effects to coal plant, and rewarded low emission plant via Clean Energy Certificates. Modelling produced by the Finkel Review indicated it was a superior policy option. It was an extraordinary development.

The Finkel Review's purpose was to produce a reform blueprint for policymakers, but its *problem definition* was partial (i.e. under-analysing the structural damage that the gas market was transmitting to the electricity market). The Clean Energy Target policy solution had also under-analysed historic design errors associated with the 20% Renewable Energy Target on which the Clean Energy Target was based – instead recommending to compound them via applying on the same design principles. The problem was obvious; the Clean Energy Target was intended to be applied after the 20% Renewable Energy Target was fully subscribed in 2020, but the effect of the sequential policies would

[44] Speaking to the ABC on Monday 5 December 2016, Minister Josh Frydenberg stated "We know that there's been a large number of bodies that have recommended an emissions intensity scheme, which is effectively a baseline and credit scheme, we'll look at that" (see Chang 2016).

necessitate a fundamental redesign of the NEM spot market. In contrast, the EIS was designed to work *with* the NEM spot market design, not against it.

5. *Garbage Can Theory*: making sense of climate change policy in the NEM

After two decades of abject policy failure, it would be naive for energy industry participants to believe the development of Australia's climate change framework might follow a conventional policy development cycle. Indeed, as Peters (2002, p. 13) explains more generally *'there may well have been a heyday of rationalist policymaking, but the contemporary world of governance does not appear to be it'*. The theory most suited to making sense of climate change policy discontinuity, and what might happen next in the Australian context, is Kingdon's (1995) multiple streams framework and in particular, *Garbage Can Theory*, a model developed from earlier works by Olsen et al. (1972).

Central to *garbage can theory* is the notion that policymaking does *not* following a conventional cycle. On the contrary, policymaking is thought to be chaotic, opportunistic and arational (Tiernan and Burke 2002). In Kingdon's model, policy solutions are developed but discarded into a *garbage can*[45] thus forming part of an ever-growing portfolio of policy solutions in search of a problem (Olsen et al 1972). For a policy solution to be revived and successfully implemented, it needs to navigate its way to the top of a congested political agenda. A *focusing event* frequently serves as the catalyst - both in helping establish an accepted *problem definition*, and, to prise open a *political window of opportunity* (Peters 2002; Howlett et al. 2014; Jones 2014). Timing is an essential element of the model (Kingdon 1995). Policy entrepreneurs or *policy influentials* are pivotal in their role of synchronising the key elements; viz. establishing a credible *problem definition*, recovering the *policy solution* from the *garbage can* and securing its widespread support all within the available *political window of opportunity* (Kingdon 1995; Peters 2002; Tiernan and Burke 2002; Howlett et al. 2014; Jones 2014; Rawat and Morris 2016).

In the present case, the collapse of the SA power system was the *focusing event* that provided a catalyst to clarify *problem definition*, viz. climate change policy discontinuity and its consequential adverse impacts on power plant investment patterns as coal generators exit the system. Sharply rising power prices prised open a *political window of opportunity*, and the Commonwealth Government appointed a *policy entrepreneur* (the Chief Scientist, Dr Alan Finkel) to lead a review of the NEM and provide recommendations on how it should "adjust".

As expected the Finkel Review[46] established climate change policy discontinuity as part of the *problem definition* (along with generation plant reliability). The Review then reached into the *energy & climate change policy garbage can* and recovered a decade-old policy solution still in search of a problem, the Clean Energy Target. What the Finkel Review didn't anticipate was the strength of *policy entrepreneurs* from the conservative party backbench, who used their influence to block the Clean Energy Target – the Finkel Review's key recommendation. By October 2017, the policy solution was abandoned by Prime Minister Turnbull.

Yet the *conservative policy entrepreneurs* themselves underestimated the need for the Commonwealth Government to resolve the matter of investment continuity by dealing with climate change policy discontinuity. Their preferred solution, new coal-fired plant, is highly

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[45] Metaphorically speaking.
[46] The Finkel Review and its members were announced on 24 October 2016. See http://www.coagenergycouncil.gov.au/publications/expert-panel-review-security-national-electricity-market for details.

problematic due to future carbon pricing risk and the fact that Ultra Super Critical coal-fired plant (sometimes referred to as High Efficiency Low Emissions of HELE) is now an expensive and risky form of generation investment by comparison to other alternatives – at least if the unit costs as expressed in Figures 2–3 are fair representations of the comparative technology costs.

The Prime Minister proceeded to call on a new set of *policy entrepreneurs* – Australia's newly-formed Energy Security Board, established by the COAG Energy Council and comprised of, amongst others, the Chairman of the Australian Energy Market Commission and a well-known and highly-respected Australian company director.[47] They proceeded to reinvent the previously discarded EIS and repurpose one of the unworkable, but necessary constructs from the Finkel Review, a generator reliability obligation. Both were turned into market mechanisms called the National Energy Guarantee – a dual mechanism which requires energy retailers to contract a certain minimum amount of dispatchable plant in each region while simultaneously decarbonising their generation contract portfolio's in line with the Commonwealth's CO_2 emission trajectory, nominally based on the 2030 Paris target. The political narrative of the scheme was ingenious. Unlike previous climate policies, there was no mention of "carbon price", "carbon tax", nor of "renewable subsidies". At the time of writing, there is every reason to believe the policy will succeed and end Australia's two decades-long climate change policy wars.

6. Policy Implications and Concluding Remarks

The NEM experienced a sharp deterioration in system conditions in 2016/17 involving a supply-side crisis. By the end of 2017 the RET will be fully subscribed with projects under construction. and Direct Action Policy funding will soon be exhausted. Both policies have a 2020 time-horizon. A policy vacuum exists vis-à-vis Australia's 2030 climate change commitments; and the gas market will remain in a state of imbalance for years to come.

Conditions for forward investment are hardly ideal and this is a significant problem. Comparative analysis with the US provides useful insights for Australian policymakers. To reiterate, we do not assert that US entry/exit statistics constitute an optimal target. Rather, we seek to highlight potential lessons for the NEM from experience in the US, where an equivalent amount of coal plant exit has occurred without the sharp rises in energy prices that have occurred in Australia.

On entry costs

In the NEM, coal plant is exiting but the rate of entry has been frustrated. There is no CO_2 policy, RET policy discontinuity has been marked and the RET is almost fully subscribed in any event. Modelling results presented in Section 3 indicate that lowest cost energy production is – CO_2 emissions intensity aside – incumbent coal plant, while the lowest new entrant – variability aside – is wind generation. Intermittency can be adequately handled by a large incumbent thermal generation fleet. But for a region like SA that has lost much of its thermal fleet through plant exit, new entrant gas-fired generation or some other form of supporting capacity is required.

On carbon pricing

If there is an upside, it is that the number of instruments actually available to government has expanded rapidly (Peters 2002). The Clean Energy Target canvassed in the Finkel Review was widely acknowledged by industry to be far from optimal, but conversely, the EIS had been discarded and industry seemed to prefer sub-optimality to a policy vacuum.

[47] John Pierce and Dr Kerry Schott AO, respectively.

At one level this is understandable. Conversely, if implemented in its intended form the Clean Energy Target would almost certainly lead to a premature redesign of the NEM. To be clear, the NEM requires certain modifications to accommodate rising levels of VRE, but a Clean Energy Target would induce its demise, not its modification. The alternate mechanism presented by the Energy Security Board represents a scheme that works *with* the NEM's world class institutional design, not against it.

At the outset, we noted that unlike the NEM, climate change policy does not require cooperative federalism to function effectively, but it does require a coherent policy architecture, and it requires an emissions reduction target to be set by the Commonwealth government, the single entity responsible for determining nationally binding targets. Experience from the US suggests that establishing the policy architecture and rules of engagement at the state-level (i.e. within the NEM Rules via SA legislation with mirror legislation in all NEM jurisdictions) as the Energy Security Board has proposed, will provide a more durable result given partisan differences at the national level.

On coal
Despite an apparent political impasse, the flow of money is clear enough. Industry anticipates climate change policy will limit CO_2 emissions. Accordingly, there are no known plans for investment in new coal plant despite advocacy by certain members of parliament. If quantitative estimates contained in Figures 2–3 remain reasonable reflections of entry costs, we should not anticipate new (unsubsidised) coal proposals in the near term either. But as other coal-fired generators exit, remaining coal plant become more important to system stability in the short- to medium-term. The quantitative analysis in Figure 3 indicates incumbent coal plant remains the cheapest form of power generation – CO_2 emissions aside. Incumbent fleet reliability has been deteriorating for some time with 75% of generators exceeding original engineering design lives (Simshauser 2014). Consequently, re-investment in such plant will become enormously important, both to accommodate sharply rising VRE, and to stabilise spot electricity prices. Policy mechanisms to reinforce this outcome will be important – and this is inherent in the design presented by the Energy Security Board.

On gas
For regions such as SA which have lost their base plant through exit, this still leaves a remaining gap in low-cost new entrant base/semi-base plant – whatever the source. Ultimately, climate change policy uncertainty and gas market imbalances need to be resolved. As with the Finkel Review, this article has touched seldom and lightly on problems in the gas market. Those problems need an early resolution, not policymaker reticence. If gas prices were set at competitive levels, gas-fired generation plant stock may or may not change – this is for the market to determine. But at scarcity pricing levels as currently exist, we can be confident of what will happen next; nothing. There is barely any evidence of new entrant gas-fired generation plant being committed despite record electricity prices. Incumbent gas-fired generation continues to play a vitally important role in terms of reliability but when setting prices, they are doing so at substantially elevated levels, and those prices are being shadowed by a rising portion of the coal generation fleet, and VRE entrants, to the detriment of consumers. Resolution will require major policy intervention on both the demand and supply sides.

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APPENDIX I

In order to analyse entry dynamics and relevant policy settings, it is helpful to identify generalised long run marginal costs of the NEM's entrants. The *PF Model,* a dynamic multi-period post-tax discounted cash flow model, has been designed specifically for this purpose. It solves for multiple generating technologies, business combinations and financing structures and simultaneously determines convergent price, debt-sizing and post-tax equity returns, K_e. Outputs are similar to levelised cost estimates but with a level of detail well beyond conventional Levelised Cost of Electricity Model estimates because corporate and project financing constraints and taxation variables are co-optimised. Key data inputs are presented in Tables A1-A2 for five new entrant technologies over three time-horizons with two financing structures:

Table A1 - Technology Assumptions 2007-2017

Technology	Capex	Installed Capacity	Generating Units	Unit Heat Rate	Unit Fuel Cost	Capacity Factor	Fixed O&M Cost	Variable O&M	Capital Works	Auxillary Load	Carbon Intensity
	($/kW)	(MW)	(MW)	(kJ/kWh)	($/GJ)	(%)	($/MW/a)	($/MWh)	(%)	(%)	(t/MWh)
2007 Inputs											
Black Coal	1,500	1,000	2	9,500	1.00	90%	48,000	1.00	0.25%	7.00%	0.87
Brown Coal	2,250	1,000	2	12,150	0.40	90%	55,000	1.30	0.25%	8.00%	1.10
CCGT	1,200	380	1	7,000	3.25	85%	10,000	3.00	0.05%	2.00%	0.36
Wind	2,100	200	100	-	-	37%	40,000	1.00	0.05%	2.00%	-
Solar PV	4,000	20	-	-	-	24%	62,000	-	0.05%	0.50%	-
2012 Inputs											
Black Coal	2,250	1,000	2	9,000	1.25	90%	49,250	2.00	0.25%	7.10%	0.82
Brown Coal	3,000	1,000	2	11,613	0.40	90%	60,250	4.00	0.25%	9.60%	1.05
CCGT	1,250	380	1	6,965	5.50	85%	10,000	7.00	0.05%	3.00%	0.36
Wind	2,500	450	180	-	-	39%	45,000	1.00	0.05%	2.00%	-
Solar PV	3,500	100	-	-	-	28%	59,435		0.05%	0.50%	-
2017 Inputs											
Black Coal	3,050	1,000	2	8,450	1.54	90%	50,500	4.00	0.25%	7.10%	0.77
Brown Coal	4,000	1,000	2	11,150	0.40	90%	65,500	5.00	0.25%	9.60%	1.01
CCGT	1,500	380	1	6,930	8.00	85%	10,000	7.00	0.05%	3.00%	0.36
Wind	1,787	450	118	-	-	41%	50,000	1.00	0.05%	2.00%	-
Solar PV	1,500	100	-	-	-	30%	56,870	-	0.05%	1.00%	-

Table A2 - Corporate Finance Assumptions

Wind & Solar		2007	2012	2017		Coal & Gas		2007	2012	2017
Debt Sizing Constraints						Debt Sizing Constraints				
- DSCR	(times)	1.35	1.35	1.35		- FFO/I	(times)	5	5	5
- LLCR	(times)	1.35	1.35	1.35		- FFO/D	(times)	3	3	3
- Gearing Limit	(%)	85.0	85.0	65.0		- Gearing Limit	(%)	35.0	35.0	35.0
- Default	(times)	1.10	1.10	1.10						
Project Finance Facilities - Tenor						Corporate 'BBB' Bond Issue				
- Tranche 1 (Bullet)	(Yrs)	5	5	5		- Tranche 1 (Bullet)	(Yrs)	5	5	5
- Tranche 1 Refi	(Yrs)	13-20	13-20	13-20		- Tranche 1 Refi	(Yrs)	13-20	13-20	13-20
- Tranche 2 (Amort.)	(Yrs)	12	12	7		- Tranche 2 (Amort.)	(Yrs)	12	12	7
- Tranche 2 Refi	(Yrs)	6-13	6-13	6-13		- Tranche 2 Refi	(Yrs)	6-13	6-13	6-13
- Notional amortisation	(Yrs)	18-25	18-25	18-25		- Notional amortisation	(Yrs)	18-25	18-25	18-25
Project Finance Facilities - Pricing						BBB' Bond Pricing				
- Tranche 1 Swap	(%)	6.14	3.69	2.45		- Tranche 1	(%)	6.69	6.26	3.74
- Tranche 1 Margin	(bps)	120	250	200		- Tranche 1 Margin	(bps)	54	257	129
- Tranche 2 Swap	(%)	6.10	3.98	2.66		- Tranche 2	(%)	6.78	6.55	4.15
- Tranche 2 Margin	(bps)	140	275	220		- Tranche 2 Margin	(bps)	69	257	149
- Tranche 1	(%)	7.34	6.19	4.45		- Tranche 1	(%)	6.69	6.26	3.74
- Tranche 2	(%)	7.50	6.73	4.86		- Tranche 2	(%)	6.78	6.55	4.15
- Tranche 1&2 Refi	(%)	7.50	6.73	4.86		- Tranche 1&2 Refi	(%)	6.78	6.55	4.15
- Post Tax Equity	(%)	15.0	12.0	8.5		- Post Tax Equity	(%)	12.0	12.0	12.0

Costs increase annually by a forecast general inflation rate (CPI). Prices escalate at a discount to CPI. Inflation rates for revenue streams π_j^R and cost streams π_j^C in period (year) *j* are calculated as follows:

$$\pi_j^R = \left[1 + \left(\frac{CPI \times \alpha_R}{100}\right)\right]^j \text{, and } \pi_j^C = \left[1 + \left(\frac{CPI \times \alpha_C}{100}\right)\right]^j \quad (1)$$

The discounted value for α_R reflects single factor learning rates that characterise generating technologies.

Energy output ρ_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period j. Plant auxillary losses Aux^i arising from on-site electrical loads are deducted.

$$\rho_j^i = CF_j^i . k^i . (1 - Aux^i) \quad (2)$$

A convergent electricity price for the *i*th plant $\left(p^{i\varepsilon}\right)$ is calculated in year one and escalated per eq. (1).[48] Thus revenue for the *i*th plant in each period *j* is defined as follows:

$$R_j^i = \left(\rho_j^i . p^{i\varepsilon} . \pi_j^R\right) \quad (3)$$

In order to define marginal running costs, the thermal efficiency for each generation technology ζ^i needs to be defined. The constant term '3600'[49] is divided by ζ^i to convert

[48] Note that thermal plant also earns ancillary services revenue, which in the model equates to about 0.3% of electricity sales. This has been the historic average although as VRE increases, this can be expected to change dramatically.
[49] The derivation of the constant term 3600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3600 Joules.

the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the j^{th} period is then calculated by the product of short run marginal production costs by generation output ρ_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{ \left[\left(\frac{\left({}^{3600}/_{\zeta^i} \right)}{1000} . f^i + v^i \right) + \left(g^i . CP_j \right) \right] . \rho_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i \right) . \frac{\left({}^{3600}/_{\zeta^i} \right)}{1000} \right\} \tag{4}$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in $/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i . k^i . \pi_j^C \tag{5}$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the j^{th} period can therefore be defined as follows:

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i \right) \tag{6}$$

Capital Costs $\left(X_0^i \right)$ for each plant *i* are Overnight Capital Costs and incurred in year 0.[50] Ongoing capital spending for each period *j* is determined as the inflated annual assumed capital works program.

$$x_j^i = c_j^i . \pi_j^C \tag{7}$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L} \right) + \left(\frac{x_j^i}{L+1-j} \right) \tag{8}$$

From here, taxation payable $\left(\tau_j^i \right)$ at the corporate taxation rate (τ_c) is applied to $EBITDA_j^i$ less Interest on Loans $\left(I_j^i \right)$ later defined in (16), less d_j^i. To the extent $\left(\tau_j^i \right)$ results in non-positive outcome, tax losses $\left(L_j^i \right)$ are carried forward and offset against future periods.

$$Max\left(\tau_j^i , 0 \right) = \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i \right) . \tau_c \tag{9}$$

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project

[50] The model is capable of dealing with multi-period construction programs such that $X_j^i = -\sum_{k=1}^{N} C_k . (1 + K_e)^{-k}$. However, for the present exercise, all plant capital costs are 'Overnight Capital Costs' (i.e. as if the plant were purchased at the completion of construction) and therefore include an allowance for capitalised interest during construction.

financings. Debt structures include semi-permanent amortising facilities and bullet facilities.

Corporate Finance involve 5- and 7-year bond issues with an implied ‘BBB’ credit rating. Project Finance include a 5-7 year bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an18-25 year period depending on the technoligy. The second facility commences with a tenor of 7-12 years as an amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years. The decision tree for the two tranches of debt was the same, so for the Debt Tranche where T = 1 or 2, the calculation is as follows:

$$if\ j\begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i.S \end{cases} \tag{10}$$

D_0^i refers to the total amount of debt used in the project. The split (S) of the debt between each facility refers to the manner in which debt is apportioned to each tranche. In the model, 35% of debt is assigned to Tranche 1 and the remainder to Tranche 2. Principal P_{j-1}^i refers to the amount of principal repayment for tranche *T* in period *j* and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-(1+(R_T^Z+C_T^Z))^{-n}}{R_T^Z+C_T^Z}\right]} \middle| z \begin{cases} = VI \\ = PF \end{cases} \right) \tag{11}$$

In (15), R_T is the relevant interest rate swap (5yr, 7yr or 12yr) and C_T is the credit spread or margin relevant to the issued Debt Tranche. The relevant interest payment in the *j*th period $\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_j^i = DT_j^i \times (R_T^z + C_T^z) \tag{12}$$

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the i^{th} plant is calculated as the sum of the above components for the two debt tranches in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (eq.10). This is determined by the product of the gearing level and the Overnight Capital Cost (X_0^i). Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing ‘BBB’ rated bonds) and Independent Power Producers using Project Finance (PF).

$$if\ \gamma \begin{cases} = VI, Min\left(\frac{FFO_j^i}{I_j^i}\right) \geq \delta_j^{VI} \wedge Min\left(\frac{D_j^i}{EBITDA_j^i}\right) \geq \omega_j^{VI} \forall j \ \left| FFO_j^i = \left(EBITDA_j^i - x_j^i\right) \right. \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall j \ \left| \ DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i}, LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \right. \end{cases} \tag{13}$$

The variables δ_j^{VI} and ω_j^{VI} are exogenously determined by credit rating agencies and are outlined in Table 3. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios.

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies. The relevant equation to solve for the price $(p^{i\varepsilon})$ given expected equity returns (K_e) whilst simultaneously meeting the binding constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF} given the relevant business combination is as follows:

$$-X_0^i + \sum_{j=1}^N \left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^N x_j^i.(1+K_e)^{-(j)} - D_0^i \tag{14}$$

The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$-X_0^i + \sum_{j=1}^N \left[\left(p^{i\varepsilon}.\rho_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.\rho_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^N x_j^i.(1+K_e)^{-(j)} - D_0^i \tag{15}$$

The terms are then rearranged such that only the $p^{i\varepsilon}$ term is on the left hand side of the equation:

Let $IRR \equiv K_e$

$$\sum_{j=1}^N (1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^N \left[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^N x_j^i.(1+K_e)^{-(j)} + D_0^i \tag{16}$$

The model then solves for P^ε such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^N (1-\tau_c).P^\varepsilon.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^N \left((1-\tau_c).\vartheta_j^i + (1-\tau_c).FOM_j^i + (1-\tau_c).\left(I_j^i\right) + P_j^i - \tau_c.d_j^i - \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^N (1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^N x_j^i.(1+K_e)^{-(j)} + D_0^i}{\sum_{j=1}^N (1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} \tag{17}$$