UNIVERSITY OF CAMBRIDGE
Faculty of Economics

Cambridge Working Papers in Economics

Cambridge Working Papers in Economics: 1875

ON ENTRY COST DYNAMICS IN AUSTRALIA'S NATIONAL ELECTRICITY MARKET

Paul Simshauser Joel Gilmore

21 December 2018

In theory, well designed electricity markets should deliver an efficient mix of technologies at least-cost. But energy market theories and energy market modelling are based upon equilibrium analysis and in practice electricity markets can be off-equilibrium for extended periods. Near-term spot and forward contract prices can and do fall well below, or substantially exceed, relevant entry cost benchmarks and associated long run equilibrium prices. However, given sufficient time higher prices, on average or during certain periods, create incentives for new entrant plant which in turn has the effect of capping longer-dated average spot price expectations at the estimated cost of the relevant new entrant technologies. In this article, we trace generalised new entrant benchmarks and their relationship to spot price outcomes in Australia's National Electricity Market over the 20-year period to 2018; from coal, to gas and more recently to variable renewables plus firming, notionally provided by – or shadow priced at – the carrying cost of an Open Cycle Gas Turbine. This latest entry benchmark relies implicitly, but critically, on the gains from exchange in organised spot markets, using existing spare capacity. As aging coal plant exit, gains from exchange may gradually diminish with 'notional firming' increasingly and necessarily being met by physical firming. At this point, the benchmark must once again move to a new technology set.

UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

On entry cost dynamics in Australia's National Electricity Market

EPRG Working Paper 1841

Cambridge Working Paper in Economics 1875

Paul Simshauser and Joel Gilmore

Abstract In theory, well designed electricity markets should deliver an efficient mix of technologies at least-cost. But energy market theories and energy market modelling are based upon equilibrium analysis and in practice electricity markets can be off-equilibrium for extended periods. Near-term spot and forward contract prices can and do fall well below, or substantially exceed, relevant entry cost benchmarks and associated long run equilibrium prices. However, given sufficient time higher prices, on average or during certain periods, create incentives for new entrant plant which in turn has the effect of capping longer-dated average spot price expectations at the estimated cost of the relevant new entrant technologies. In this article, we trace generalised new entrant benchmarks and their relationship to spot price outcomes in Australia's National Electricity Market over the 20-year period to 2018; from coal, to gas and more recently to variable renewables plus firming, notionally provided by – or shadow priced at – the carrying cost of an Open Cycle Gas Turbine. This latest entry benchmark relies implicitly, but critically, on the gains from exchange in organised spot markets, using existing spare capacity. As aging coal plant exit, gains from exchange may gradually diminish with 'notional firming' increasingly and necessarily being met by physical firming. At this point, the benchmark must once again move to a new technology set.

Keywords Variable Renewable Energy, Electricity Prices, Power System Planning

JEL Classification D61, L94, L11 and Q40

Contact p.simshauser@griffith.edu.au

Publication December 2018
Financial Support

On entry cost dynamics in Australia's National Electricity Market

Paul Simshauser ♣♠ and Joel Gilmore♠
December 2018

Abstract
In theory, well designed electricity markets should deliver an efficient mix of technologies at least-cost. But energy market theories and energy market modelling are based upon equilibrium analysis and in practice electricity markets can be off-equilibrium for extended periods. Near-term spot and forward contract prices can and do fall well below, or substantially exceed, relevant entry cost benchmarks and associated long run equilibrium prices. However, given sufficient time higher prices, on average or during certain periods, create incentives for new entrant plant which in turn has the effect of capping longer-dated average spot price expectations at the estimated cost of the relevant new entrant technologies. In this article, we trace generalised new entrant benchmarks and their relationship to spot price outcomes in Australia's National Electricity Market over the 20-year period to 2018; from coal, to gas and more recently to variable renewables plus firming, notionally provided by – or shadow priced at – the carrying cost of an Open Cycle Gas Turbine. This latest entry benchmark relies implicitly, but critically, on the gains from exchange in organised spot markets, using existing spare capacity. As aging coal plant exit, gains from exchange may gradually diminish with 'notional firming' increasingly and necessarily being met by physical firming. At this point, the benchmark must once again move to a new technology set…

Keywords: Variable Renewable Energy, Electricity Prices, Power System Planning.
JEL Codes: D61, L94, L11 and Q40.

1. Introduction

Australia's National Electricity Market (NEM) is unique amongst restructured electricity systems with its centrepiece being a single real-time gross pool platform (MacGill, 2010). Every five minutes, a new spot electricity price is formed under a uniform first-price auction clearing mechanism, along with eight Frequency Control Ancillary Service spot market prices cleared in the same manner, with electricity production and frequency control services co-optimised across five imperfectly interconnected States/regions (Simshauser & Tiernan, 2018). A single Independent Market Operator coordinates all generators and bulk loads in all regions and all spot markets, and, again somewhat uniquely, without any formal day-ahead or capacity market (Riesz et al. 2015). Instead, Resource Adequacy is driven by the NEM's very high Value of Lost Load (VoLL) or Market Price Cap; at AUD[1] $14,500/MWh it is amongst the highest in the world. Forward derivative contracts are traded both on-exchange and over-the-counter and have historically exhibited turnover of 300+% of physical trade. Certain regions and seasons are significantly more liquid than others.

Historically, NEM spot prices have exhibited considerable volatility within and across reporting periods. Along with short run variations associated with weather and anthropogenic patterns, medium-run supply-imbalances drive volatility. Over the long run, given aggregate demand growth, or more relevantly in the current environment with flat final demand – the exit of aging coal plant "*at-scale*" – average spot prices will gravitate towards the cost of the relevant new entrant technology (or technology set). That is, higher prices on average, or during certain periods, will create incentives for targeted new entrant plant which in turn has the effect of capping longer-dated average spot price expectations at the estimated cost of the relevant new entrant technologies.

♣ Professor of Economics, Griffith Business School, Griffith University. Research Associate, Energy Policy Research Group, University of Cambridge.
♠ Head of Corporate Development & Head of Regulatory Affairs at Infigen Energy, respectively.

[1] All figures presented in Australian Dollars. At the time of writing, AUD/US ~ 0.72 and AUD/GBP ~ 0.57.

Over time, prices on average or during certain periods also regulate the plant mix as defined by the rich blend of fixed and variable costs associated with various generating technologies (i.e. base, intermediate, peak, variable renewable). Security-constrained power system simulation models reinforce this view. These sophisticated Monte Carlo-based Linear Programming models - derived from the original joint work in the field by Electricite de France Chief Economist Marcel Boiteux and State Electricity Commission of Victoria Chief Engineer Dr Rob Booth - apply the principles of Calabrese (1947), Boiteux (1949), Berrie (1967) and Booth (1972) and are at their core based on equilibrium analysis.

Of course, in practice energy markets are frequently off-equilibrium. Near-term spot and forward contract prices can and do fall well below, or substantially exceed the relevant entry cost benchmarks and sometimes for extended periods due to transient structural imbalances within the plant stock. That structural imbalances exist in the first place means the cure to rising prices is not always more base plant. Understanding these principles is quite essential to understanding the fundamentals of power system planning, likely investment commitments and the long run marginal cost of power generation. That is, central to the task of power system modelling and investment analysis is the equilibrium price of power, and for expediency we will refer to this as the new entrant cost. Terminology is important; new entrant cost is often used interchangeably with long run marginal cost; but in this article we are dealing specifically with the former for reasons outlined in Turvey (2000).

Australia's NEM exhibited two decades of consistent economic and technical performance. However, over the period between 2012-2018 average spot prices more than doubled; from $30/MWh in 2012 to more than $80/MWh in 2018 in nominal terms. During FY17 the Independent Market Operator issued more than 20 Lack off Reserve notices and operated the power system outside a secure operating state (i.e. for more than 30 minutes at a time) on almost a dozen occasions[2]. Two major blackouts occurred in the South Australian region, including a complete system collapse. The cause of these conditions can be summarised briefly[3] as 1) the exit of 5000MW of coal plant with an average notification period of just 5 months; 2) a domestic gas market experiencing shortages due to the commissioning of excess LNG export capacity; and 3) policy discontinuity vis-à-vis carbon pricing and renewable portfolio standards (Nelson, 2018; Simshauser & Tiernan, 2018).

While the speed, scale and consequential short-run impacts of coal plant exit represented a form of market failure, at one level a clinical analysis of supply-side dynamics reveals the NEM institutional design maintained its consistent economic performance. Policy discontinuity in prior periods made the timing of coal plant exit highly unpredictable, and severe structural problems in the adjacent market for natural gas all but eliminated the flexibility of the NEM's gas-fired fleet to respond in a manner that it otherwise should have. Ultimately, policy discontinuity caused capacity shortfalls to emerge and prices increased – as they should.

New investments in plant capacity are now running at record levels; over the period 2016-2018, more than 8,000MW or ~$16 billion of large-scale plant[4] was committed – all of it variable renewable capacity as Figure 2 later reveals. But the intriguing aspect of this recent investment cycle has been the material change in entry cost dynamics – which as our subsequent quantitative analysis reveals, is the fourth such transition over the past two decades.

Although power project investment commitment involves revenue analysis for discrete projects based on market modelling and associated forecasts, individual project costs and resources vary significantly; thus an understanding of historic and future trends provides

---

[2] See AEMC (2018) at footnote 28.
[3] The triggers for each event were different; in one case by unexpectedly high demand, in another due to extreme weather and unknown fault ride through settings. However, the pace of change has made determining appropriate operating envelopes more challenging.
[4] Small amounts of non-scheduled biomass/biofuel plant were also constructed or expanded, as well as some 5,000 MW of rooftop solar PV capacity.

useful context vis-à-vis benchmark pricing. This can inform the indicative cost of supplying customers into the future, but also highlights key inputs and sensitivities for long-term planning and policy.

To generalise, analysts currently describe NEM entry costs as being "renewables plus firming" (see for example Nelson, 2018). In this instance, renewables means wind or solar PV, and firming is *notionally* (or shadow-) priced at the carrying cost of an Open Cycle Gas Turbine (OCGT) plant – either physically or financially through derivative instruments. Over the medium term this benchmark appears sound enough.

But over the long run, important implicit assumptions underpinning this particular (and notional) new entrant technology set may not hold if low marginal running cost coal plant continue to exit *at-scale*. This benchmark relies critically on exhausting available gains from exchange in the NEMs mandatory gross pool and may understate grid connection and frequency control ancillary services costs (i.e. the evidence suggesting they are rising). To understand this set of dynamics, it helps to reflect on how the reference new entrant technology and associated costs/prices have changed over time, and this forms the primary purpose of this article.

This article is structured as follows. Section 2 introduces the PF Model and relevant input assumptions. Section 3 presents Model results. Section 4 reviews changes to fuel cost fundamentals and its implications for the market, while Section 5 summarises entry dynamics over the 20-year period 1999-2018 and contrasts this with spot prices. Section 6 examines the stability of the prevailing new entrant benchmark. Conclusions follow.

2. Entry costs and the PF Model

The *PF Model*, a dynamic multi-period post-tax discounted cash flow model, has been specifically designed to produce generalised estimates of the cost of plant entry. The model solves for multiple generating technologies, business combinations and financing structures and simultaneously determines convergent price, debt-sizing and post-tax equity returns, K_e. Model outputs are similar to levelised cost estimates but with a level of detail well beyond conventional traditional Levelised Cost of Electricity Model results because corporate and project financing constraints and taxation variables are co-optimised. The model logic is organised as follows:

2.1 Model Overview

In the PF Model, 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).[5] Thus revenue for the i^{th} plant in each period j is defined as follows:

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

In order to define marginal running costs, the thermal efficiency for each generation technology ζ^i needs to be defined. The constant term '3600'[6] is divided by ζ^i to convert 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.[7] 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.

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

---

[5] 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.

[6] The derivation of the constant term 3600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3600 Joules.

[7] 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.

$$L_j^i = Min(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i \right). \tau_c) \tag{10}$$

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 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 an 18-25 year period (depending on the technology). 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 DT = 1 or 2, the calculation is as follows:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i.S \end{cases} \tag{11}$$

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:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-(1+\left(R_{Tj}^Z + C_{Tj}^Z\right))^{-n}}{R_{Tj}^Z + C_{Tj}^Z} \right]} \middle| z \begin{cases} = VI \\ = PF \end{cases} \right) \tag{12}$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} 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:

$$I_j^i = DT_j^i \times (R_{Tj}^z + C_{Tj}^z) \tag{13}$$

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 (as per eq.11). This is determined by the product of the gearing level and the Overnight Capital Cost $\left(X_0^i\right)$. 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).

$$iif\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\ j \ \left| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\ j \ \right| FFO_j^i = \left(EBITDA_j^i - x_j^i \right) \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall\ j \ \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i} \right| LLCR_j = \frac{\sum_{j=1}^{N} \left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j} \right]}{D_j^i} \end{cases} \tag{14}$$

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. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N} \left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} \tag{15}$$

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies[8] along with relevant equations to solve for the price $(p^{i\varepsilon})$ given expected equity returns (K_e) whilst simultaneously meeting the constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF} given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

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

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

Let $IRR \equiv K_e$

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

The model then solves for $p^{i\varepsilon}$ such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\left((1-\tau_c).\vartheta_j^i+(1-\tau_c).FOM_j^i+(1-\tau_c).\left(I_j^i\right)+P_j^i-\tau_c.d_j^i-\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^{N}(1-\tau_c).\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)}+D_0^i}{\sum_{j=1}^{N}(1-\tau_c).\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} \tag{18}$$

2.2 Model Assumptions

Key data inputs for the PF Model are presented in Tables 1-2 and cover five new entrant technologies over four distinct time-horizons, and two financing structures.

[8] The return on equity in the PF Model is assumed to provide fair compensation to equity investors for the systematic risk associated with the investment, and is estimated using the Capital Asset Pricing Model (CAPM). For tractability, electricity prices in the PF Model are assumed to be deterministic rather than stochastic. In practice, however, there is a high degree of uncertainty over future electricity prices. Further, entry into the market involves significant sunk cost. In the presence of significant future uncertainty and large sunk costs, the option value of waiting to invest can be material. Once the decision to invest is taken, the option to delay investment to resolve further future uncertainty is extinguished. The extinguishment of a valuable option represents a cost to investors that ought to be accounted for in the investment decision. If the option value foregone is positive, then the investment hurdle rate will be larger than K_e, the required return on equity estimated using the CAPM.

Table 1: Technology Assumptions 1999-2018

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)
Incumbent - 1999											
Black Coal	1,000	1,000	2	10,000	1.10	87.5%	52,500	1.00	0.25%	7.50%	0.92
2004 Inputs											
Black Coal	1,400	1,000	2	9,500	0.70	87.5%	45,000	-	0.25%	7.00%	0.86
CCGT	1,000	400	1	7,000	3.00	70%	8,000	4.00	0.05%	3.00%	0.40
OCGT	700	300	2	11,300	3.00	10%	5,600	4.00	0.05%	1.00%	0.60
Wind	2,250	30	30	-	-	35%	35,000	-	0.05%	0.00%	-
2007 Inputs											
Black Coal	1,500	1,000	2	9,500	2.00	87.5%	48,000	1.00	0.25%	7.00%	0.86
CCGT	1,250	400	1	7,000	3.00	70%	9,000	4.00	0.05%	3.00%	0.40
OCGT	875	300	2	11,300	3.50	10%	6,300	4.00	0.05%	0.00%	0.60
Wind	2,100	50	28	-	-	35%	37,000	3.00	0.05%	0.00%	-
2012 Inputs											
Black Coal	2,250	1,000	2	9,000	2.00	90%	49,250	2.00	0.25%	7.10%	0.81
CCGT	1,275	400	1	6,965	6.00	70%	9,500	7.00	0.05%	3.00%	0.36
OCGT	893	300	2	11,300	7.00	10%	6,650	10.00	0.05%	0.00%	0.60
Wind	2,500	250	100	-	-	39%	41,000	3.00	0.05%	0.00%	-
Solar PV	3,500	100	-	-	-	25%	35,000		0.05%	0.00%	-
2018 Inputs											
Black Coal	3,050	1,000	2	8,571	2.78	90%	50,500	4.00	0.25%	7.10%	0.77
CCGT	1,500	400	1	6,930	8.50	70%	10,000	7.00	0.05%	3.00%	0.36
OCGT	1,050	500	2	11,300	10.00	0%	7,000	10.00	0.05%	1.00%	0.60
Wind	1,975	450	118	-	-	39%	45,000	3.00	0.05%	0.00%	-
Solar PV	1,550	100	-	-	-	26%	30,000	-	0.05%	0.00%	-

Table 2: Corporate & Project Finance Assumptions

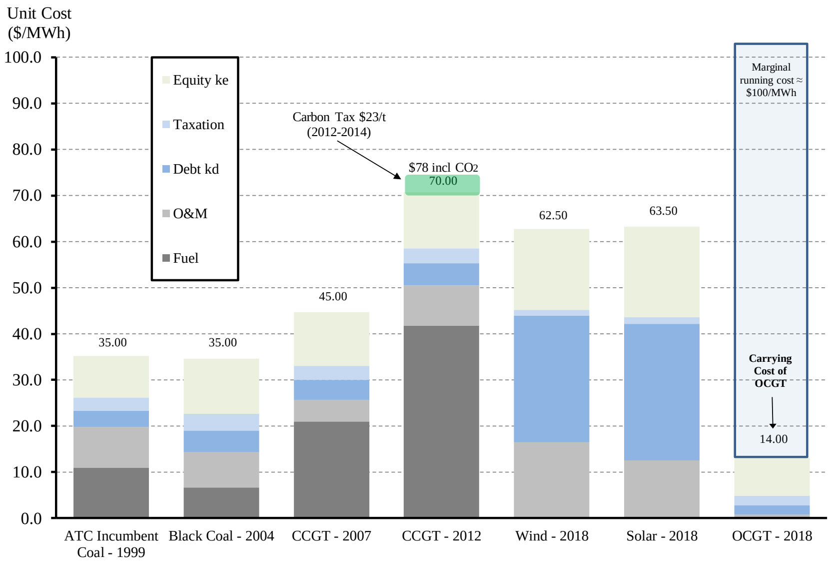
Coal & Gas		2004	2007	2012	2018	Wind & Solar		2004	2007	2012	2018
Debt Sizing Constraints						Debt Sizing Constraints					
- FFO/I	(times)	5	5	5	5	- DSCR	(times)	1.35	1.35	1.35	1.35
- FFO/D	(times)	3	3	3	3	- LLCR	(times)	1.35	1.35	1.35	1.35
- Gearing Limit	(%)	40.0	40.0	40.0	40.0	- Gearing Limit	(%)	85.0	85.0	85.0	65.0
						- Default	(times)	1.10	1.10	1.10	1.10
Corporate 'BBB' Bond Issue						Project Finance Facilities - Tenor					
- Tranche 1 (Bullet)	(Yrs)	5	5	5	5	- Tranche 1 (Bullet)	(Yrs)	5	5	5	5
- Tranche 1 Refi	(Yrs)	13-20	13-20	13-20	13-20	- Tranche 1 Refi	(Yrs)	13-20	13-20	13-20	13-20
- Tranche 2 (Amort.)	(Yrs)	12	12	10	7	- Tranche 2 (Amort.)	(Yrs)	10	10	10	7
- Notional amortisation	(Yrs)	18-25	18-25	18-25	18-25	- Notional amortisation	(Yrs)	18-25	18-25	18-25	18-25
BBB' Bond Pricing						Project Finance Facilities - Pricing					
- Tranche 1	(%)	7.66	7.69	6.14	3.60	- Tranche 1 Swap	(%)	5.72	7.00	3.66	2.55
- Tranche 1 Margin	(bps)	54	69	247	105	- Tranche 1 Margin	(bps)	120	150	250	200
- Tranche 2	(%)	6.38	7.66	6.90	3.97	- Tranche 2 Swap	(%)	3.67	4.90	4.10	2.68
- Tranche 2 Margin	(bps)	271	275	280	129	- Tranche 2 Margin	(bps)	140	170	270	220
- Tranche 1	(%)	7.66	7.69	6.14	3.60	- Tranche 1	(%)	6.92	8.50	6.16	4.55
- Tranche 2	(%)	6.38	7.66	6.90	3.97	- Tranche 2	(%)	5.07	6.60	6.80	4.88
- Tranche 1&2 Refi	(%)	6.38	7.66	6.90	3.97	- Tranche 1&2 Refi	(%)	7.50	7.50	6.80	4.88
- Post Tax Equity Coal	(%)	12.0	12.0	15.0	15.0	- Post Tax Equity	(%)	12.0	12.0	12.0	10.0
- Post Tax Equity Gas	(%)	0.0	12.0	12.0	12.0						

3. Model results

Tables 1-2 provide sufficient data inputs for the PF Model to produce generalised entry cost estimates (i.e. Average Total Cost, including normal profit) for new entrant plant across four specific timeframes, viz. 2004, 2007, 2012 and 2018, along with the Average Total Cost of Incumbent Coal plant in 1999. These dates were selected because they capture our view of four distinct phases of generator entry, which in turn helps explain NEM average price dynamics and associated technology trends, as presented in the following sections.

Figure 1 presents the relevant benchmark technology for each of the specific timeframes outlined above (a full comparative analysis of all technologies in each of the specific timeframes, i.e. 2004, 2007, 2012 and 2018, is presented in Appendix I). For clarity, in the PF Model conventional technologies including Coal, Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT) plant are assumed to be Balance Sheet-financed (gearing ca.32-38%, meeting -BBB credit metrics) while variable renewable plant (viz. Wind, Solar PV) are assumed to be Project Financed (ca.65-70% debt) and underpinned by long-dated PPAs, which in turn are assumed to be written by BBB-rated counterparties. Notice that the Average Total Cost of Incumbent Coal plant in 1999 was ~$35/MWh in nominal terms.

Figure 1: **New entrant technologies and entry costs (nominal dollars)**



3.1 Period 1: 1999 to 2004 – Black Coal

From 1999-2004, Supercritical coal plant was the dominant technology and accordingly, formed an equilibrium price in forward forecasts and investment planning. This is far more than theory. 3000MW of Supercritical black coal plant was committed in the Queensland region of the NEM during this period. The new entrant cost in 2004 was about $35/MWh in nominal terms – that is, almost $4/MWh lower than the average total cost of incumbent coal plant (which by 2004 was ~$39/MWh after accounting for cost inflation). A falling spot price outlook by 2004 ultimately regulated the extent of new Supercritical coal plant entry.

3.2 Period 2: 2005 to 2011 – CCGT

From 2005-2011, CCGT plant overtook coal as the dominant new entrant technology, and formed the new market benchmark. As the new entrant benchmark moved from coal to CCGT plant, entry costs moved from $35/MWh to $45/MWh in nominal terms. The change occurred when there was no foreseeable link to international oil prices, and when natural gas was therefore sold in a competitive market on a cost-plus-margin basis. Long-dated (10-15 year) Gas Supply Agreements for CCGT plant could be secured for $2.50 – 4.00/GJ as Figure 7 later reveals. Although slightly higher cost than new coal plant this technological switch was primarily driven by an abundance of natural gas, and the expectation by utilities and investors of an Australian Emissions Trading Scheme[9] – CO_2 emissions from CCGT plant (0.4t/MWh) being less than half their coal-fired counterparts (0.9t/MWh).

Importantly, there were no new coal plant commitments from 2005 onwards – the risk of future carbon pricing being an important variable.[10] About 5000MW of gas plant was committed throughout the NEM in Period 2; 2000 MW of which was CCGT and at least 1000MW of semi-intermediate (i.e. hard-working) OCGT plant – the latter made possible by the availability of very low cost natural gas.

3.3 Period 3: 2012 to 2015 – CCGT, but Renewables enter

By 2012 the forward price of natural gas had increased to $6/GJ. Consequently, so too did the entry cost of CCGT plant – rising from $45/MWh to $70/MWh. Australia's (temporary $23/t) Carbon Tax was in force throughout the period 2012-2014 but the policy was

[9] From 2007-2009 an Emissions Trading Scheme was bi-partisan policy. See Simshauser & Tiernan (2018).
[10] The 750MW Kogan Creek coal-fired plant in Queensland was the last investment committed (in 2004) and was commissioned in 2007.

subsequently dismantled following a Commonwealth Government election (see Simshauser & Tiernan, 2018).

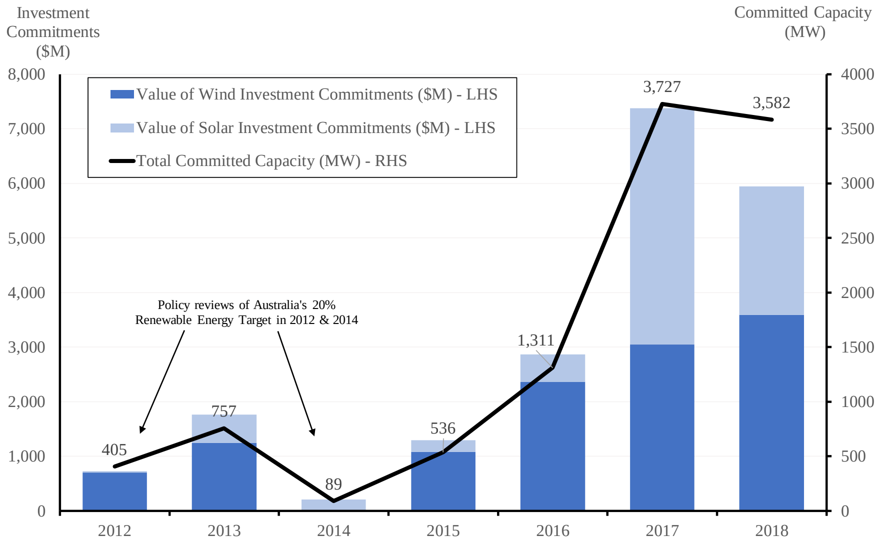
In spite of the Carbon Tax, sharply rising natural gas prices, contracting energy demand in the NEM (the first such episode on record), and the ramp-up of Australia's Renewable Portfolio Standard to a 20% market share by 2020 meant there was no economic basis for new CCGT plant to enter.[11] Entry became the domain of renewables through policy mechanisms. Renewable Energy Certificates had a traded average of $38/MWh over 2012-2015 (with considerable inter-temporal variation driven by policy discontinuity) which when combined with low forward electricity prices facilitated a certain minimum level of variable renewable plant investment commitments in line with the 2020 schedule. Although, as Figure 2 reveals, policy discontinuity in 2012 and in 2014 produced distinct investment troughs (Simshauser & Tiernan, 2018).

Even though there was no CCGT plant entry, throughout this period forward power system models would still rely on CCGT entry costs as an important input for base load investment into the future, and, CCGT plant frequently formed the basis for calculating longer-dated Renewable Energy Certificate pricing. That is, long run equilibrium Certificate prices for renewables could be derived by reference to the entry cost of wind (as the lowest cost renewable technology at the time) *less* the entry cost of a CCGT plant after adjusting for any volume weighted price differences. Also during this period, the supply-demand imbalance meant underlying 'black' electricity prices remained low and would ultimately drive the exit of 5000MW of coal plant.

3.4 Period 4: 2016 to 2020+ – *renewables plus 'notional' firming*

During the period 2016-2018 the cost of new variable renewable plant (i.e. wind and solar PV) had fallen quite considerably while simultaneously, coal plant exit at-scale produced a tight market with spot and forward contract prices surging. Over this short period, more than 8000MW of new variable renewable plant was committed (Figure 2).

Figure 2: **Australian Variable Renewable Energy Investment Commitments (2012-2018)[12]**



Source: BNEF.

Recall from Figure 1 (and see also Appendix I Fig.14) that in 2018 variable renewables formed the lowest cost entrant at $62.50/MWh (variability aside) with some reported transactions in the $50s - albeit for specific sites or with transaction-specific assumptions

[11] In particular as Figure 13 (Appendix I) notes, given elevated prices for natural gas the marginal running cost of new CCGT plant remained higher than the marginal running cost of incumbent coal plant even after accounting for the $23/t Carbon Tax.
[12] Data also includes investment commitments from Western Australia and the Northern Territory as well as NEM regions.

including *two-step pricing*[13]). But as is well understood in energy economics, using a single entry cost to describe variable renewable energy resources represents a flawed metric because it treats technology outputs as homogeneous products, as if governed by the law of one price (Joskow, 2011; Mills & Wiser, 2012; Edenhofer et al. 2013; Simshauser, 2018).

Consequently, the carrying cost or shadow price of an OCGT plant forms the notional firming component (along with the upper price limit of *financial* products used for firming) and completes the reference technology set in 2018, and collectively amounts to about $75-$80/MWh. In practice, the total cost of energy delivery will vary depending on market dynamics, including how often firming capacity is used, as well as the potential to earn additional revenue from OCGT plant (discussed further in Section 6). To be clear, our analysis overlooks rising costs of Frequency Control Ancillary Services and what appears to be rising grid connection costs – the extent to which is yet to be fully revealed given most of the investment commitments in Figure 2 are yet to be commissioned.[14]

Although variable renewable plant entry in 2016-2018 was driven by Australia's 20% Renewable Portfolio Standard, coincident high spot prices produced a rising interest in market-driven wind and solar PV plant investments, along with a focus on how new variable renewable plant should be operated and integrated over the long-term in the NEM. High spot market prices were in turn underpinned by elevated prices for coal and natural gas due to their newly found linkages with seaborne markets, the significance of which is examined in Section 4.

4. Fuel Prices: coal and natural gas

Most of the NEM's 22,500MW coal-fired fleet, which has historically produced 150,000GWh per annum (cf. NEM load of c.190,000GWh) was built by former state-owned monopoly electricity commissions with plant design lives of 200,000 Equivalent Operating Hours (i.e. 25-30 years). While a number of coal plants in the NEM were developed as vertically integrated mine-mouth power stations[15], many in the Queensland and New South Wales regions are not – they were developed with very long-dated, low cost coal supply agreements (legacy coal contracts). These legacy coal contracts typically spanned periods of 15-25 years which in turn underpinned both private sector mine development, and the future output of the State Electricity Commission's coal plant.

4.1 Coal prices

Over the past decade an increasing number of legacy contracts have matured, at which point coal-fired plants have been forced to replace historic ultra-low-cost contracts (ca.$1.00/GJ) with shorter term contracts linked to the Newcastle FOB export coal price. Newcastle 5500kcal coal futures contract prices have risen to more than $90/t ($4+/GJ). The significance of this is highlighted in Figure 3, which traces the Newcastle FOB price (RHS axis, shaded area chart) and contrasts the marginal running cost of coal plant on legacy coal contracts (dashed black line, LHS axis) with the marginal running cost of coal plant based on the Newcastle export price (solid line chart, LHS axis). Given NEM black coal plant heat rates range from 9320 – 10910 kJ/kWh and marginal loss factors of 0.975, 5500kcal coal

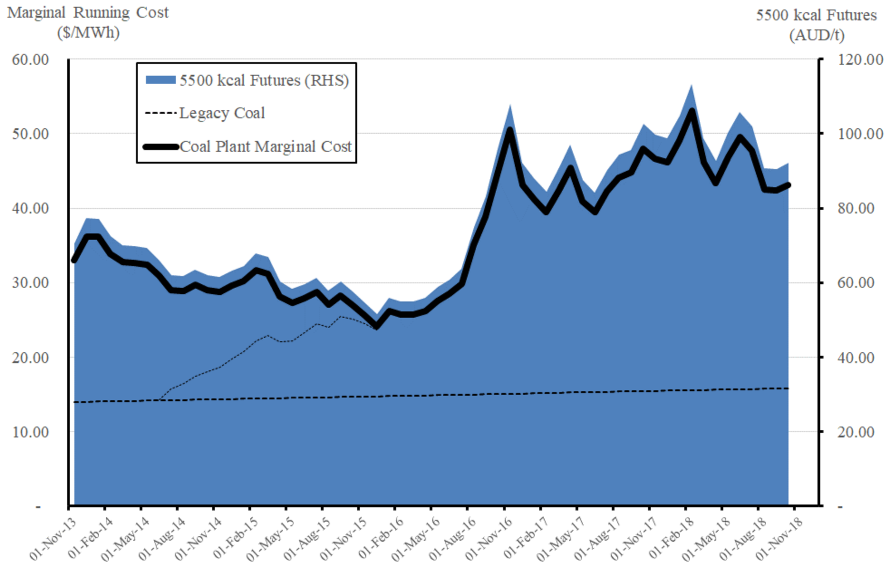
[13] Recent PPA transactions for renewables in the $50s/MWh appear to reflect either of i). unique sites with excellent resource and network connection characteristics; or ii). more commonly, what we have labelled "two-step pricing". With two-step pricing, a low cost 15-year PPA is written is written (first step), and then for project years 16-30 elevated prices are assumed to prevail (second step) reflecting an elevated (but highly uncertain) forecast of future spot prices. The combination of the low contracted PPA prices (years 1-15) and high expected future spot prices (years 16-30) appear to collectively meet threshold equity returns. The implication of this two-step pricing is that Average Total Cost of such projects is higher than recent PPA pricing suggests. Based on our input assumptions, we find the Average Total Cost, levelized over 30 years, to be $62.50/MWh. This is quite different from the European experience in which renewables receive a high Feed-in Tariff for an initial period, followed by lower expected market returns in the latter period.

[14] In the South Australian region where intermittent renewables already comprise 45+% of final demand, Frequency Control Ancillary Service Costs have increased very substantially. From 2011-2014 aggregate FCAS costs in the South Australian region averaged $5.1 million per annum. From 2015-2018 they had risen to $37.0 million per annum. In relative terms, FCAS costs increased from 0.5% of market value over the period 2011-2014 (i.e. the spot electricity market comprising the remaining 99.5%) to 3.4% over the period 2015-2018.

[15] Prominent vertically integrated power stations which own their coal mining operations include the Yang A & B and Yallourn in Victoria, and Millmerran, Kogan Creek and Tarong in Queensland.

prices are now producing plant marginal running costs of about $50/MWh, well above the historic $15/MWh production costs associated with legacy coal contract supply. This becomes evident through an examination of the NEM's Aggregate Supply Curve after isolating the 17,675MW (summer-rated) black coal fleet, in Figure 4.

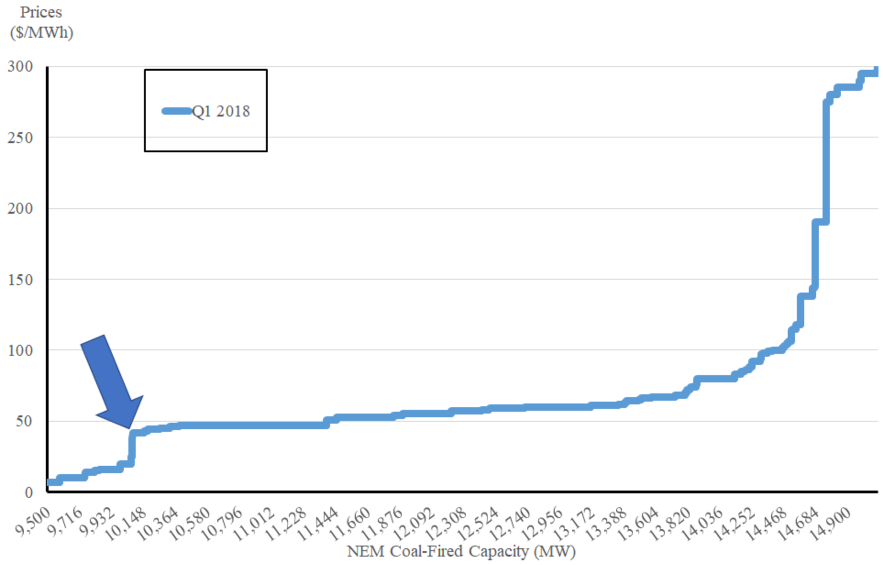
Figure 3: **Newcastle FOB coal price & coal plant marginal running costs 2013-2018**



Source: CEFC.

Of special interest Figure 4 is the flat section of the black coal plant supply function, which ranges from 10,000MW to 14,500MW (commencing from the blue arrow). Historically, this component of the supply curve would be priced in the $15-$20/MWh range, but from 2015 onwards has progressively lifted to > $50/MWh. Any subsequent policy which has the effect of placing an explicit price on carbon would see a further structural change.

Figure 4: **NEM Supply Curve: Black Coal-Fired Generation Fleet**

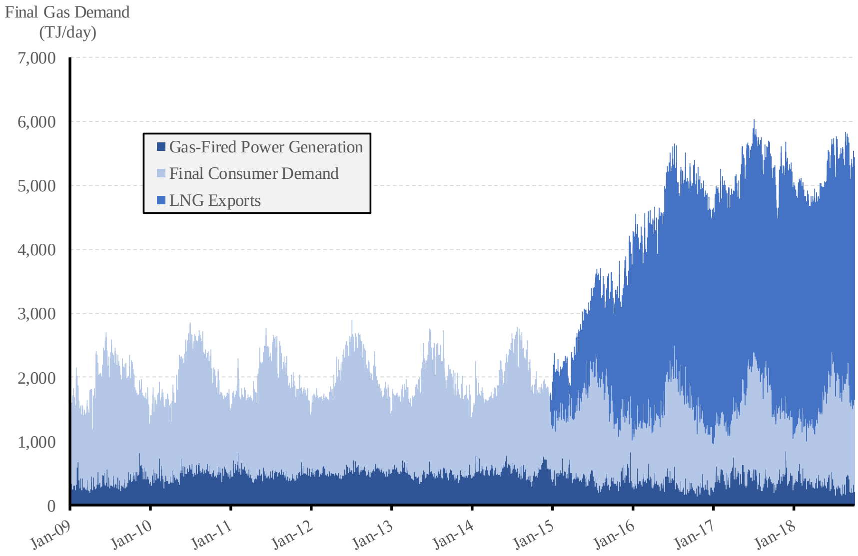


Source: AEMO.

4.2 Natural gas prices and the impact of LNG exports

Central to the NEM's current market conditions, and to the medium-term outlook, is the dire circumstances facing the Australian east coast market for natural gas. Over the period 2014-2016, three large LNG export plants in the Queensland region of the NEM were commissioned. The LNG export terminals led to an almost 3-fold increase in final Australian east coast gas demand, rising from 630PJa to 1850PJa during FY2018 (Simshauser & Nelson, 2015; Grafton et al. 2017; Billimoria et al, 2018). This is illustrated in Figure 5, which presents final gas demand (daily resolution, TJ/d) from 2009-2018.

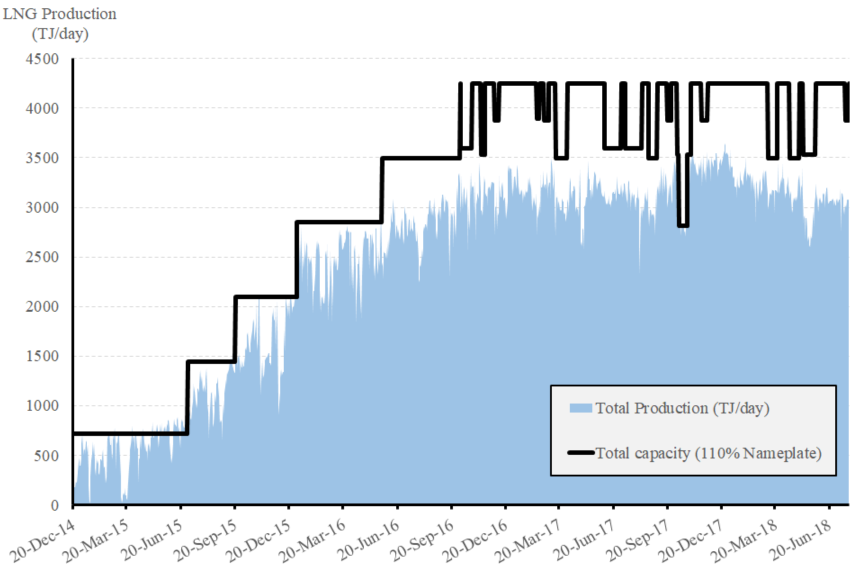
Figure 5: **Expansion in aggregate demand for natural gas (TJ/day, 2009-2018)**



Source: GMAT.

What Figure 5 does not capture is the under-utilisation of new LNG export plant capacity, and the consequential pressure this has placed on the domestic gas market. Figure 6 presents the ramp-up and ongoing LNG plant capacity (daily resolution) and contrasts this with actual production:

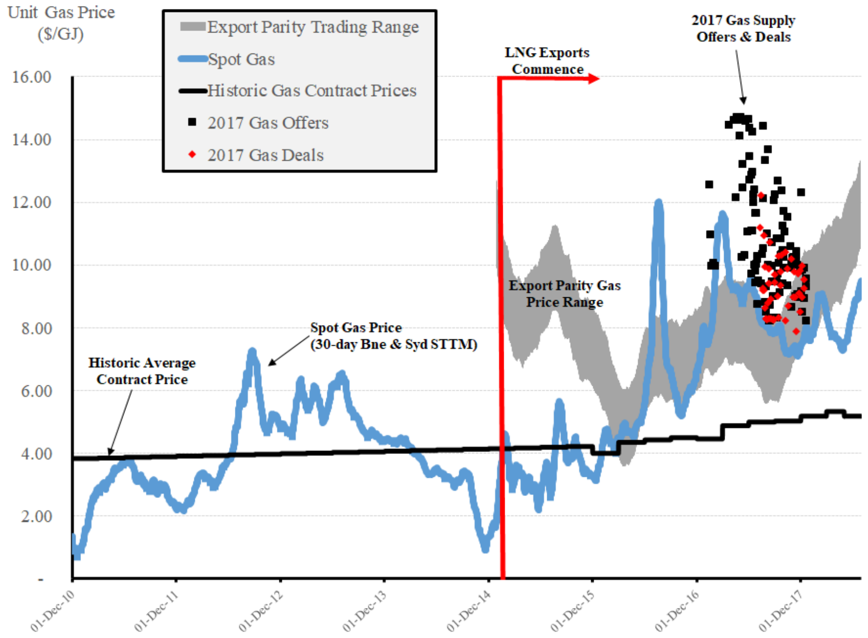
Figure 6: **Australian East Coast LNG Export Capacity vs LNG Production**



Source: GMAT.

The significance of excess LNG capacity for the NEM was the linking of the domestic gas market to international price dynamics. As with coal contracts, legacy gas supply contract prices were extremely low by global standards ($2.50 - $4/GJ) and once expired have been progressively replaced with oil-linked supply contracts with reduced tenors, elasticity-adjusted volumes and in certain cases, double-netback margins (i.e. marking gas in southern NEM regions to the export commodity price, then adding transport costs to the north, then adding transport costs back to a southern delivery point). The evolution of east coast gas prices from 2010-2018 is illustrated in Figure 7 – which has four important gas price parameters: i). the solid black line series traces legacy contract prices; ii). the blue line series traces the 30-day moving average spot gas prices and note the step up once all 3 x LNG terminals were commissioned in 2016, i.e. the point at which the gas market entered a state of 'structural imbalance'; iii). the grey shaded area traces the export parity price of gas; and iv). the black and red markers show domestic gas offers and transactions, respectively, for 1-5 year forward gas supply contracts. Above all, domestic gas prices have shifted from $3-4/GJ to $8-12/GJ.

Figure 7: **Eastern Australia gas market prices**

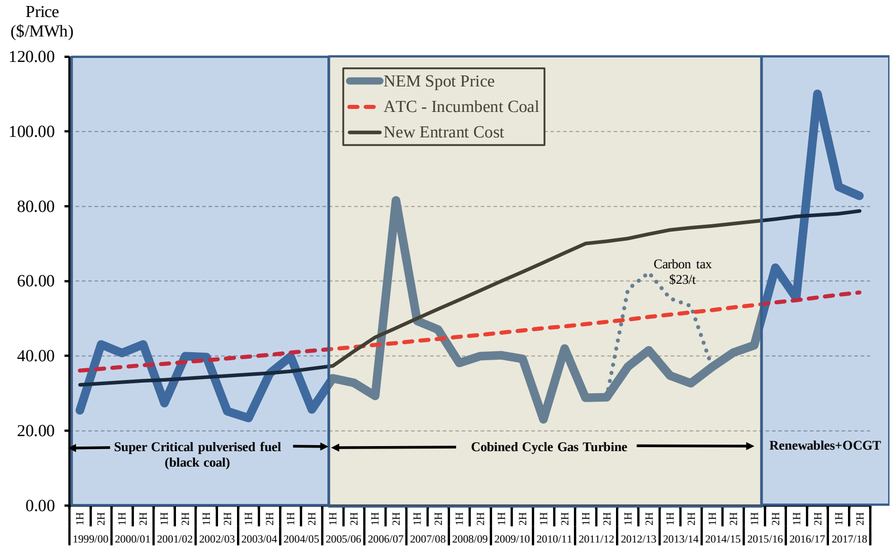


Sources: GMAT, ACCC.

5. Entry dynamics in the NEM 1999-2018

To summarise our modelling results (see Figure 1 and Appendix I), the Average Total Cost of incumbent plant in 1999 was $35/MWh. From 1999-2004 the new entrant benchmark was coal at $35/MWh. From 2005-2011 CCGT plant formed the new entrant at $45/MWh, but by 2012-2015 gas prices had risen sharply and CCGT plant costs followed to $70/MWh ($78 including the $23/t Carbon Tax). From 2016 onwards, the falling cost of renewables meant it formed a part of a new entrant benchmark (albeit part of a technology set including an OCGT). This new entrant benchmark has been underpinned by a characteristic quite unfamiliar to NEM participants - fuel costs that are increasingly linked to international/seaborne markets. Just as 5500kCal coal futures and forward prices for LNG (and by implication, domestic natural gas) surged, the entry cost of renewables began to fall, aided by a shrinking window to monetise projects before Australia's 20% Renewable Portfolio Standard would be fully subscribed, record low interest rates, record high Renewable Certificate prices, and a rush of institutional money into a solar PV boom. These dynamics produced a new number for the power system's long run equilibrium of about $75 - $80/MWh, which as we noted earlier is comprised of $60 - $65/MWh for wind and $14/MWh for the carrying cost or shadow price of an OCGT (but excludes any Frequency Control Ancillary Service costs, and the rising cost and complexity of grid connection). The trend in new entrant costs and spot prices over the 20-year period 1998-2018 is illustrated in Figure 8.

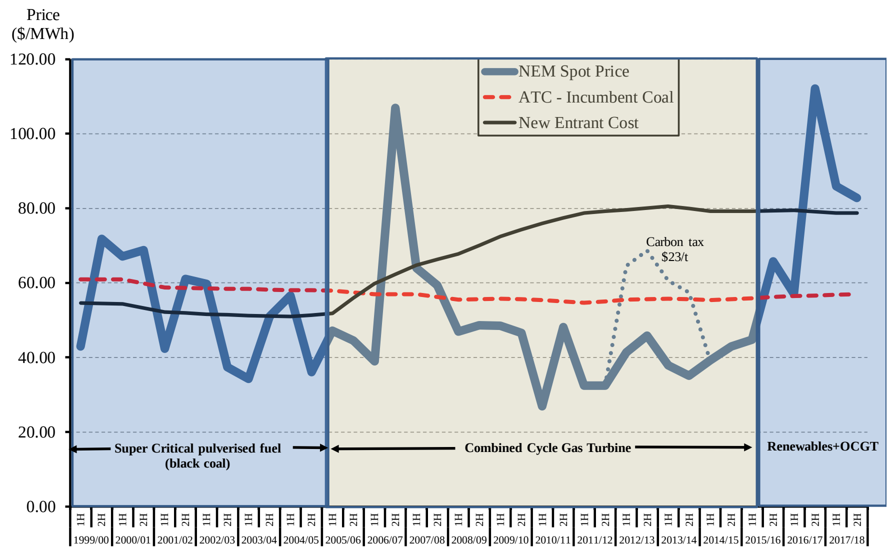
Figure 8: **20-year nominal NEM Spot Prices and New Entrant Costs: 1999-2018**



Source: NEMMCo, AEMO, PF Model.

Prima facie, power prices appear to have risen very sharply, rising as they have from $35/MWh to $75-80/MWh. But these data and the stream of results in Figure 8 data are in nominal dollars, and 1999 was a long time ago. Taking the results and presenting them in constant (2018) dollars indicates cleaner power generation is capable of being achieved at not very much increased cost.

Figure 9: **NEM Spot Prices and New Entrant Costs: 1999-2018 (constant 2018 $)**



Source: NEMMCo, AEMO, PF Model, Australian Bureau of Statistics.

6. On the stability of new entrant benchmarks

In an energy-only market with a very high VoLL, the assumption that renewables and OCGT (or battery) firming represents the benchmark entry cost ultimately relies critically on *gains from exchange* in the NEM using existing spare capacity. For this new entrant cost benchmark and associated equilibrium price to hold, it is important that energy is provided by the variable renewable generator, and during low production periods the OCGT plant (or battery) provides related insurance against extreme price spikes. That is, the current benchmark technology set is not *actually* intended to physically produce at unity load factors. Far from it. When the variable renewables component of the benchmark technology set is operating at low or zero load, it notionally "purchases" from existing spare capacity in the spot market (i.e. from existing coal, CCGT, hydro or uncorrelated renewable plant) and the

OCGT plant is merely used to *"clip"* exposures to very high spot price spikes, thus maintaining the imputed Average Total Cost within the specified range.[16]

To be clear, this set of assumptions is *entirely appropriate* for the NEM. A fundamental objective of the mandatory gross pool institutional design and an organised spot market is to enable participants to efficiently and cost effectively exhaust gains from exchange to meet firm forward contract commitments – acknowledging that when one provider is short, others will be long, and this exchange maximises welfare.

Benchmark prices therefore depend on the composition of the balance of the market as well as policy externalities. As such, and holding fuel prices constant, there are (at least) two reasons why the NEM's new entrant benchmark may be replaced by an alternate technology set.

6.1 Ongoing coal plant exit at-scale

What happens when coal plant exits are so material that gains from exchange in the spot market are exhausted, such that "notional firming" from OCGT plant becomes increasingly "physical firming"? Well before this point in time, the economics of the reference technology set will begin to deteriorate and a new benchmark equilibrium will necessarily emerge. To physically back an intermittent portfolio by running an OCGT plant on $10/GJ fuel equates to a marginal running cost of at least $110/MWh, plus fixed and sunk capital costs of $14/MWh – regardless of whether the plant is operating (i.e. the insurance premium). Adding these costs to variable renewables would quickly surpass the reference benchmark of $75-80/MWh for firmed variable renewables. Recent published research by the Australian Renewable Energy Agency similarly demonstrates elevated cost results for variable renewables that have been physically-firmed by battery storage (see Lovegrove et al. 2018).

The ongoing entry of low cost variable renewable energy plants are capable of replacing most, but not all, of the output from exiting coal plant. A certain residual (~10-15%) needs to be covered by some other form of flexible generation. As coal plant exit, this residual may ultimately be provided by new battery storage capacity, new pumped-storage hydro, solar thermal (with storage) or some other dispatchable renewable resource such as biomass.

But there is a nuance in our analytical framework and modelling – a key element underpinning our analysis is the collision between electricity market theory, and the harsh realities of applied corporate finance. The need to "firm" a variable renewable plant at the plant owner level can only exist if non-trivial merchant spot price exposure exists (e.g. when legacy run-of-plant PPAs have expired). Given financing constraints and the need for some degree of forward revenue certainty, few if any merchant plants are devoid of firm forward derivative contract commitments. Firming merchant variable renewable plant requires being able to withstand elongated periods of low production against the financial exposures arising from firm forward derivative contract commitments, including exposures to a $14,500/MWh VoLL.

As gains from exchange in organised spot markets are exhausted, any need to physically back variable renewable plant with new capacity during extended price-volatility events is likely to be delivered by natural gas for reasons of production run-time (i.e. length and continuity) – at least based on our existing technology cost assumptions. Furthermore, our modelling indicates that once an OCGT plant is forced to operate more than ~20-30% Annual Capacity Factor it is more efficient to transition to other gas-fired generation technologies with superior thermal and environmental efficiency (viz. CCGT).

[16] Conversely, an OCGT can be used to produce additional revenue even when the variable renewable resource is high, selling resources to the grid.

6.2 Binding carbon constraints

Australia's international CO_2 commitments[17] amount to a 26-28% reduction against a 2005 baseline. With the surge in variable renewable investments from 2016 onwards, if the electricity sector is asked to do only a pro-rata share of CO_2 emission reductions (i.e. current Conservative Liberal/National Party policy) the requirement for a price on carbon in Australia prior to 2030 is ambiguous. However, for Australia to meet its economy-wide target, the electricity sector must do more than its pro-rata share (i.e. current Labor Party Policy). In this latter scenario, even though renewables plus notional firming forms the current new entrant benchmark, the natural replacement of existing coal capacity is not sufficient to transform the power system at a pace that matches the required reductions (viz. ca.45% reduction in electricity sector CO_2 emissions by 2030).

In the long-term, a price on carbon – whether implicit or explicit – is necessary to ensure ongoing reductions in CO_2 emissions. There are many mechanisms which could achieve this; an emissions intensity trading scheme, a retailer emissions obligation, an explicit price on carbon, a regulatory standard or the regulated closure of coal plant over time (such as the federal regulations in Canada).

6.3 Returning to CCGT

Assuming gas prices remain elevated (i.e. \$8.50+/GJ), the new entrant cost of a CCGT is closer to \$80-\$90/MWh. In practice, the new entrant portfolio mix might include some combination of all available technologies, but the cost of an CCGT should represent a robust benchmark as the coal fleet retires and the prevailing gains from exchange are progressively exhausted. Indeed, now that the British pool has lost a majority of their coal fleet, CCGT plant auctions seem to be in sharp focus as the optimal backup plant. CCGT plant can be developed relatively quickly and represent a scalable near-term solution. However, developing CCGT is not without challenges:

- In the absence of further Government intervention, high domestic gas prices are likely to persist and this makes banking such plant very complex *cf* lower capital cost OCGT plant. We noted earlier that the maximum practical capacity of LNG terminals is 1620 PJ/a (Figure 6) and when combined with (reduced) domestic load of 630 PJ/a, theoretical final gas demand totals 2250 PJ/a. At current production rates of 1850PJ/a (Figure 5), the market is 300-400 PJ/a short of theoretical final aggregate demand. For gas users in the NEM, this is a sobering prospect – the gas market appears set to remain in structural theoretical shortage for at least a decade as aggregate supply struggles to catch up, thus continuing to place pressure on forward gas prices.

- New CCGT plant represents a long-dated investment and may become time-sensitive to expected future carbon constraints in its own right – that is, the development of any non-renewable resource risks becoming a stranded asset by future carbon policy. Even now, regions such as California are pursuing energy storage as an alternative to replacing aging gas plant.

- CCGT may face competition from energy storage technologies, including battery storage and pumped-storage hydro. New energy storage could allow for further gains from exchange in the NEM (i.e. by shifting excess renewable production to high net demand periods). Currently, our modelling does not support the development of battery storage solely for the purposes of energy arbitrage – but this may change over time if battery costs continue to fall. Conversely, while battery storage has the advantage of speed and precision in dispatch, short-duration energy storage provides only an imperfect hedge against firm forward derivative contract commitments. For retail businesses in the NEM exposed to VoLL, the possibility of critical event days

[17] As a signatory to the Paris Agreement, Australia is committed to a global goal of holding average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels. This is generally accepted to require low to zero net emissions from power systems by 2050.

may still leave residual and unacceptable risks of financial loss, that is, through very low probability but high impact, elongated price spike events. That said, cost-effective energy storage would seem most likely to defer any transition from a renewables plus OCGT benchmark to a CCGT benchmark.

7. Concluding remarks

Our quantitative analysis suggests that renewables and notional firming (i.e. the carrying cost or shadow price of an OCGT plant) currently comprises the NEM's new entrant benchmark. We did not incorporate rising FCAS costs, or what appears to be rising costs of grid connection. Whether these become material will no doubt be revealed over time. Leaving aside this caveat, an implicit yet crucial assumption underpinning this reference technology-set is the existence of gains from exchange in organised spot markets, arising from existing underutilised capacity.

As aging coal plant continues to exit – through policy via explicit (or implicit) carbon pricing or end of useful life – available gains from exchange may be progressively exhausted. Under these circumstances, the role of notional backup capacity may progressively switch from a low-cost insurance product used to "clip" extreme price spikes, to an increasingly expensive form of energy production used to physically backup variable renewable production. With elevated prices for natural gas, once OCGT capacity factors rise above ~20-30%, CCGT plant becomes more economic. Of course, if the costs of energy storage technologies fall materially, it may defer the transition from OCGT to CCGT plant by facilitating greater gains from exchange through the NEM's organised spot market.

8. References

AEMC: Australian Energy Market Commission, 2018, "Annual market performance review 2017", Reliability Panel, AEMC, Sydney.

Berrie, T. 1967, "The economics of system planning in bulk electricity supply", *Electrical Review*, 22(2): 425-428.

Billimoria, F., Adisa, O. and Gordon, R. 2018, "The feasibility of cost-effective gas through network interconnectivity: Possibility or pipe dream?", *Energy*, 165B (2018): 1370-1379.

Boiteux, M. 1949, "La tarification des demandes en pointe: Application de la theorie de la vente au cout marginal", *Revue Generale de l'Electricite*, Translated by H. Izzard in *Journal of Business*, Boiteux, M. 1960, 'Peak load pricing', Journal of Business, 33(2): 157–80.

Booth, R. 1972, "Power system simulation model based on probability analysis", *IEEE Transactions on Power Apparatus and Systems*, PAS-91(1): 62-69.

Calabrese, G. 1947, "Generating reserve capacity determined by the probability method", *AIEE Transactions*, 66(1): 1439-1450.

Edenhofer, O., Hirth, L., Knopf, B., Pahle, M., Schlomer, S., Schmid, E. and Ueckerdt, F. 2013, "On the economics of renewable energy sources", *Energy Economics*, 40(2013): S12-S23.

Joskow, P. 2011, "Comparing the costs of intermittent and dispatchable electricity generating technologies", *American Economic Review*, 100(3): 238-241.

Lovegrove, K., James, G., Leitch, D., Milczarek, A., Ngo, A., Rutovitz, J., Watt, M. and Wyder, J. 2018, "Comparison of dispatchable renewable electricity options", ARENA Publication, Sydney.

MacGill, I. 2010. "Electricity market design for facilitating the integration of wind energy: experience and prospects with the Australian National Electricity Market", *Energy Policy*, 38(2010): 3180-3191.

Mills, A. & Wiser, R. 2012. "Changes in the economic value of variable generation at high penetration levels: a pilot case study of California", LBNL-5445E, Lawrence Berkeley National Laboratory.

Nelson, T. 2018, “The future of electricity generation in Australia: a case study of New South Wales”, *The Electricity Journal*, 31(2018): 42-50.

Riesz, J., Gilmore, J. & MacGill, I. 2015, “Frequency control ancillary service market design: insights from the Australian National Electricity Market”, *The Electricity Journal*, 28(3): 86-99.

Simshauser, P. 2018, “On intermittent renewable generation & the stability of Australia's National Electricity Market”, *Energy Economics*, 72(2018): 1-19.

Simshauser P. & Nelson, T. 2015. “Australia’s coal seam gas boom and the LNG entry result”, *Australian Journal of Agricultural and Resource Economics*, 59(2015): 602-623.

Simshauser P. & Tiernan, A. 2018, “Climate change policy discontinuity and its effect on Australia’s national electricity market”, *Australian Journal of Public Administration*, available at DOI: 10.1111/1467-8500.12328

Turvey, R. 2000, “What are marginal costs and how to estimate them?”, Centre for the Study of Regulated Industries, Technical Paper No.13, University of Bath.

Appendix I: PF Model Results

Figures 10-13 produce the entry costs by technology for the timeframes 2004, 2007, 2012 and 2018 respectively. Data inputs are outlined in Tables 1 and 2. Figure 10 presents 2004 entry costs. Key variables driving these results were the very low cost of coal ($0.70/GJ) and natural gas ($3.00/GJ). Coal dominated entry.

Figure 10: **New entrant technologies and entry costs in 2004**

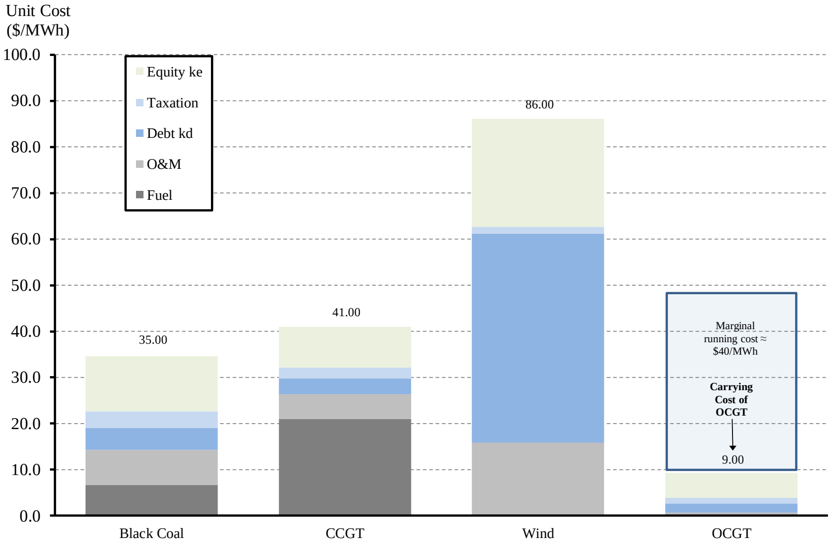


Figure 11 presents 2007 entry costs. Notice that coal plant is lower cost than CCGT plant – but during the 2007 Commonwealth Election both the Conservative Liberal/National Party Coalition and the Labour Party had a policy of implementing Cap and Trade Emissions Trading Schemes. Consequently, CCGT plant formed the new entrant benchmark – the NEM's last coal plant commitment occurred in 2004. No new coal plant has been committed since.

Figure 11: **New entrant technologies and entry costs in 2007**

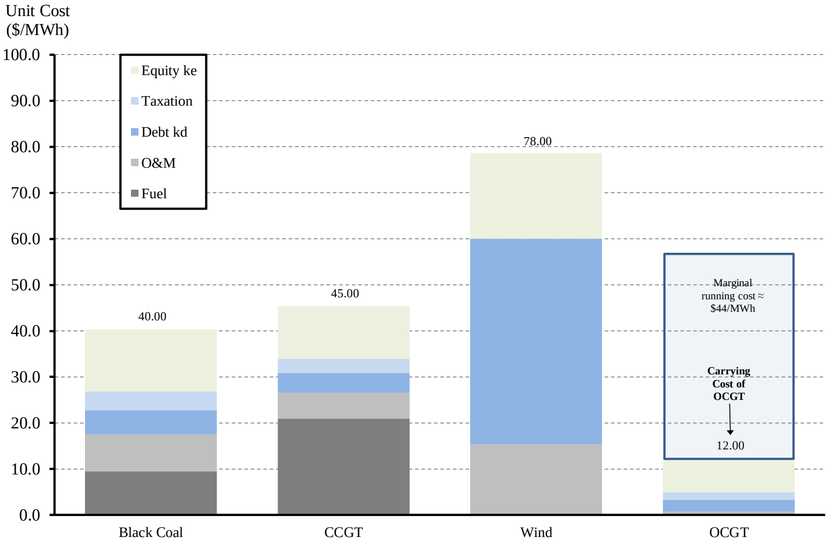


Figure 12 presents 2012 entry costs. The rising estimated cost of new coal plant was driven by a number of factors; first, capital costs had increased from $1500/kW to $2250/kW as a result of moving from a Supercritical to an UltraSupercritical benchmark (requiring more advanced materials); second, coal mining costs had increased sharply and thus the marginal cost of fuel had increased to $40/t or about

$2/GJ, and given the imminent implementation of Australia's(now defunct) $23/t carbon tax, equity returns in the model were adjusted from 12% to 15% (per Table 1). With respect to CCGT plant, new entrant cost increases from $45/MWh (in 2007) to $70/MWh were primarily driven by the price of natural gas commencing its upward drift to export parity prices, which at the time were ~$6/GJ (up from $3/GJ). Wind costs increased from 2007 to 2012 primarily due to high capital costs, shifting from $2100/kW to $2500/kW during this period.

Figure 12: **New entrant technologies and entry costs in 2012 (ex-Carbon)**

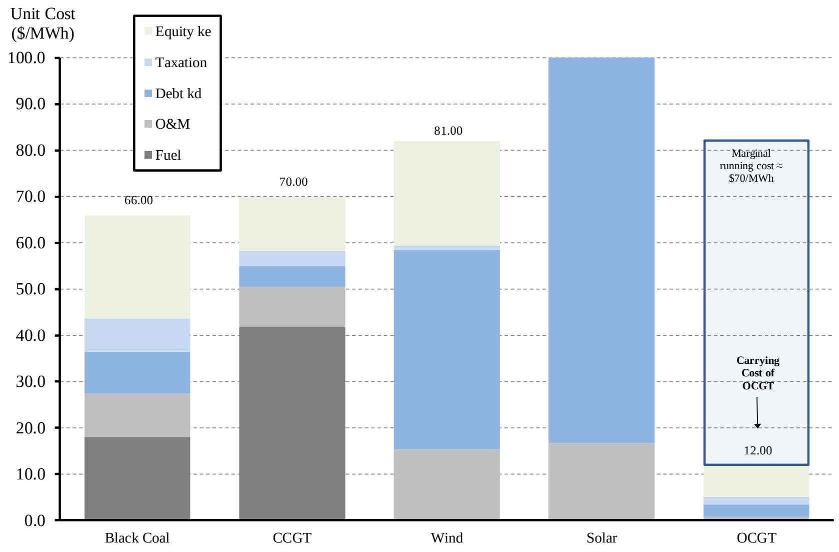


Figure 13: **New entrant technologies and entry costs in 2012 (incl. Carbon)**

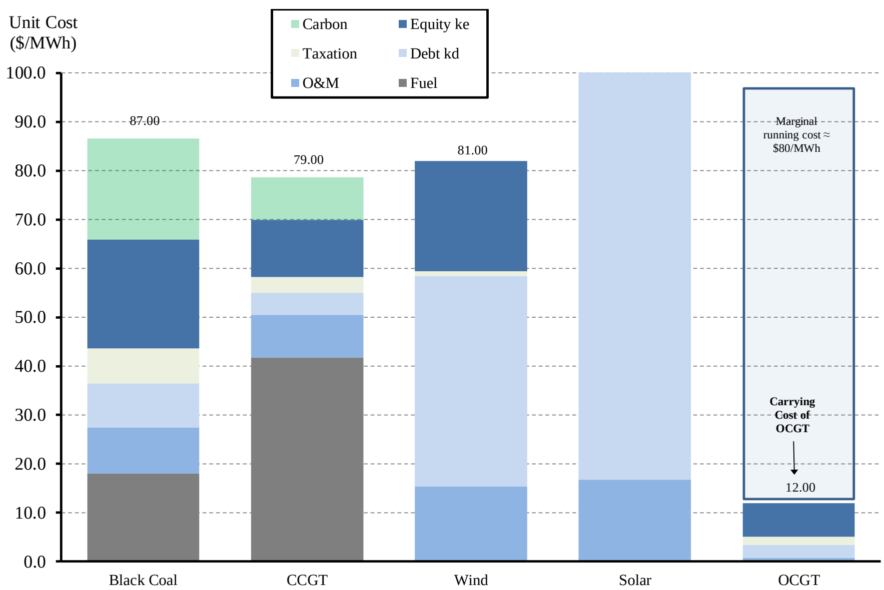


Figure 14 presents 2018 entry costs. The increase in new coal plant is driven by the same factors as the prior period. Capital costs increased to $3050/kW in line with High Efficiency Low Emissions plant costs, and coal mining costs had increased to $50/t or $2.78/GJ – albeit well below export prices (and thus the assumption is that an otherwise stranded resource is monetised at the marginal cost of extraction. CCGT plant entry costs are also being driven by the same factor, viz. the rising cost of natural gas, from $6/GJ to $8.50/GJ. The new entrant cost of variable renewables on the other hand have fallen sharply. This is being driven by plunging capital costs (e.g. wind falling from $2500/kW to $1975/kW) and by a lower equity IRR, which in our experience reduced from 12% to 10%.

Figure 14: **New entrant technologies and entry costs in 2018 (ex-Carbon)**