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The Counterfactual Scenario: are renewables cheaper?

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Abstract
In 2021 the average household electricity tariff in the National Electricity Market was ~23c/kWh. By 2025, tariffs had increased 33% to ~30c/kWh. Australians were told renewables would be cheaper, yet electricity bills had risen sharply. Are renewables cheaper? In this article, we focus on the wholesale market component of retail electricity tariffs and examine a counterfactual scenario – a world where market entrants were coal- and gas-fired generation rather than renewables. We compare these results to the NEM's transitioning plant stock, comprising a mix of incumbent coal and gas-fired generators and ever-rising levels of wind, utility-scale and rooftop solar, along with the emergent firming fleet, viz. batteries, pumped hydro and new entrant gas turbines. Even though the cost of wind has risen sharply in recent years, reversion to coal and gas – our counterfactual scenario – would result in wholesale market costs and prices ~30-50% higher. Setting aside environmental considerations, coal and gas were once unambiguously the NEM's lowest cost entrants. That period has ended. Structurally high coal plant costs and export-parity gas prices means renewables and firming assets represent the dominant new entrants to meet demand growth, and supply gaps created by aging coal plant exits.

Keywords: baseload coal, renewables, natural gas, dispatchable plant capacity.

JEL Codes: D52, D53, G12, L94 and Q40.

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1. Introduction

Over the past 15 years, electricity tariffs have been surprisingly volatile, and energy policy in Australia's National Electricity Market (NEM) has been anything but stable. In 2021, the average residential tariff in the NEM[1] had fallen to ~23c/kWh (US15c/kWh). Soon after, the Russia-Ukraine war erupted causing shocks to global gas markets (including in Australia). A series of coal plant outages in the NEM led to severe supply-side dislocation in the same period, while higher rainfalls lowered solar output. Then, electricity equipment supply-chains began to seize up, construction costs in Australia increased by more than 30%[2], and rising interest rates (given higher capital expenditure) sent debt servicing costs up by a factor of 3. Within three years, the entry cost of onshore wind projects had nearly doubled and the average residential tariff had risen by 33% to 30c/kWh (US20c/kWh) – noting that in the same period, wholesale electricity prices in the EU and UK had risen by 200-400% (Ferriani & Gazzani, 2023; Grubb, 2022).

Over the past five years, Australia's two major political parties at both national and sub-national levels entered each election cycle with well-intentioned policies designed to reduce household electricity bills. The Commonwealth and the State Governments in the NEM's largest three regions of New South Wales, Victoria and Queensland – from both sides of politics – introduced renewable policies or targets on the basis that household bills would fall. To summarise an extensive body of policy, *"renewables were cheaper"*. But the lived experience of Australian households and businesses has been different. Electricity bills have been rising, not falling.

With electricity bills rising in a so-called *cost of living crisis*, we should predict a level of energy policy instability in search of better outcomes. Sharply rising electricity bills above the general rate of inflation are a problem for society. In the typical basket of goods and services consumed by Australian households, it is hard to find a more regressive item than electricity. Dominant thought is that wealthier households consume more electricity than vulnerable households. In Australia, the quantitative evidence is that there is no correlation – the coefficient is just +0.08 and an R^2 of 0.01 (Simshauser, 2021b). British data is virtually identical (Bennett et al., 2002). And in the world's first household expenditure survey undertaken in Germany during the 1850s, the same substantive result was revealed (Stigler, 1954). In aggregate, household expenditure on energy is *regressive*.

Consequently, the political economy of 33% tariff increases over a relatively short period is *highly problematic* and would always induce a substantive policy response. The *alibi* for this statement can be observed through policy implementation. The Commonwealth and certain State governments originated *universal* household electricity rebates. Universal rebates are poorly targeted (Oorschot, 2002; Komives *et al.*, 2006) and grind against Australia's longstanding bipartisan welfare state, underpinned by the world class accuracy of our means-tested tax and transfer system (Simshauser, 2023). That universal electricity rebates exist at all tells us how serious the electricity bill problem is. This is important context for our subsequent research.

Are renewables cheaper? Our task is to unpack this line of inquiry, work through its complications and examine a *counterfactual scenario*. What would happen if we cancelled renewables? For clarity, we focus strictly on the wholesale market[3] and our counterfactual scenario examines what could be

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[1] The authors are grateful to Gavin Dufty (St Vincent de Paul) for assistance in constructing this average rate. The average tariff rate is the simple average of market offers in the four NEM mainland regions of QLD, NSW, VIC and SA – weighted by the number of household customers in each state.

[2] See [Producer Price Indexes, Australia, March 2025 | Australian Bureau of Statistics]

[3] In our modelling of wind and solar, we allocate Renewable Energy Zone transmission costs to the new entrants in a manner consistent with Simshauser & Newbery (2024). New coal and gas plants are only ascribed shallow connection costs. Any other reinforcement of the transmission backbone arising from growth in aggregate final demand and associated power flows is assumed to be allocated to the Regulatory Asset Base. Coal closures necessitate new sources of system services such as inertia and system strength, a broad category of

delivered now. This collapses down to coal, gas, wind, utility-scale and rooftop solar PV, and the two dominant forms of storage, viz. lithium-ion batteries and pumped hydro (i.e. these technologies are observed in the NEM). We start from *"the good old days"* of $40 power prices as existed in the mid-2000s. We then pull these results forward to 2025 and compare this benchmark to both renewable and counterfactual scenarios comprising coal and gas.

Headline results are as follows. On a unit cost basis, coal and gas-fired generation were *unambiguously the lowest cost technologies in the mid-2000s* (setting aside the value of CO_2 emissions). By 2025, unit fuel costs had increased at multiples above general rates of inflation. Our 2025 counterfactual scenarios, which deploy only coal and gas-fired generation to meet aggregate final demand, *prove to be surprisingly expensive*.

When we model the Queensland region given existing trajectories of generation technologies (i.e. aging coal plant, wind, utility-scale and rooftop solar) with the power system operating in a secure state via adequate new entrant dispatchable firming capacity (i.e. batteries, pumped hydro and gas turbines), we find costs and prices are ~30-50% lower than counterfactual scenarios.

This article is structured as follows. Section 2 reviews relevant literature. Section 3 introduces models and data. Sections 4 and 5 explore model results. Policy implications and concluding remarks follow.

2. Review of literature: the political economy of energy policy in Australia

In this review of literature, we examine the political economy of energy policy in Australia, and the shattering of energy policy consensus. Examining these two areas helps to frame our quantitative work in Sections 4-5.

2.1 Energy policy in Australia

To generalise, from the 1950s through to the early-2000s energy policy was largely bipartisan. While the location of new power stations frequently caused issue (Thomis, 1987; Kellow, 1996), governments did not question their expert State Electricity Commissions on technology selection and plant mix[4], or the market in the early post-NEM reform era. Coal-fired generation was unambiguously lowest cost and over time, many of our state-based power systems would become amongst the lowest cost in the world. But as with many countries, overcapacity emerged during the 1980s and early 1990s (Schmalensee, 2021) – particularly in New South Wales and Victoria (Booth, 2000).

Necessary reforms to the electricity industry and associated policy initiatives during the 1990s would ultimately secure bipartisan support – albeit awkwardly (Havyatt, 2022). Remarkably in hindsight, a united approach across the Commonwealth and all State governments was required, and achieved, to create the NEM – a notable achievement of Australia's federated system (Simshauser and Tiernan, 2019).

Climate policy – which in Australia translated to renewable targets, rooftop solar policies and carbon pricing – had been contested from the early-2000s (Nelson, 2015). In this sense, the electricity industry could be argued to have been drawn into the political arena during a Commonwealth election campaign in 2007 on the grounds of climate policy.

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services required for fault detection and AC wave form stability. New gas turbines with clutches (or the retrofitting of existing gas turbines as has been done in Queensland) can provide these services independent of energy. Furthermore, grid forming capabilities of batteries also form part of the lowest cost portfolio solution. New renewable projects can pay for such services from the transmission network, setting an upper bound of ~$3/MWh on projects. Some dedicated synchronous condensers (with flywheels) will also form part of the optimal portfolio – and at ~6 per region will add c.$1-2/MWh to transmission network costs.

[4] As one reviewer noted, there were one or two hydroelectric schemes which form exceptions to the rule.

If there was any doubt, the once *apolitical* electricity industry found itself on centre stage of politics from 2012 due to a pronounced price cycle which spanned the period 2007-2015 (Havyatt, 2020). Evidently, the electricity industry has failed to exit the political arena ever since (Jones, 2014; Crowley, 2017). Both energy and climate policy remain central battlegrounds in Commonwealth and State elections (Simshauser and Tiernan, 2019; Crowley, 2021).

- **Networks and Environmental Charges**

From 2007-2015, residential tariffs jumped from 12.5c/kWh (US8.1c/kWh) – at that time the second lowest in the world – to 29.4c/kWh (US19.1c/kWh). This 133.9% increase dwarfed changes in the consumer price index of ~23.9% (Simshauser, 2014). Household electricity tariffs had doubled in real terms in a period of just eight years (Simshauser, 2021a). Understandably, a price shock of this magnitude warranted a policy response.

The 2007-2015 tariff increases were driven by a confluence of events including an episode of policy-induced network gold plating (Mountain and Littlechild, 2010), rising interest rates (Simshauser, 2025), a new carbon tax (Jones, 2014), recovery of overly generous rooftop solar feed-in tariffs (FiT), rooftop capital subsidies (Nelson et al., 2012), and declining aggregate (grid-supplied) electricity demand – following a period of particularly strong and sustained load growth[5] (Simshauser, 2014). Policy adjustments followed, including cancellation of premium FiTs (Dodd and Nelson, 2022), reductions to rooftop solar capital subsidies (Nelson et al., 2012), universal cuts to regulated Transmission and Distribution Network Opex allowances (-9%) and Network Capex allowances (-27%), reductions in network regulated rates of return (Simshauser, 2021a), and through an election, Australia's carbon tax was repealed (Crowley, 2017). From 2015 through to 2021, household tariffs fell in real *and nominal* terms.

- **Natural Gas**

Just as end-use electricity tariffs began to fall (c.2015-), conditions in the market for natural gas began to deteriorate rapidly. Energy policy would remain on centre stage. Three LNG export terminals were commissioned in Queensland when only two should have proceeded (Grafton et al., 2018; Taylor and Hunter, 2018). Excess LNG capacity created a sustained structural shortage of natural gas on the east coast of Australia that remains to this day (McConnell and Sandiford, 2020). LNG investment commitments were made during the late-2000's and early-2010's, and being a (semi-strong) efficient market, forward contracts for natural gas doubled (~$6), then tripled (~$9 or US$5.54/MMBtu) in value against the historically stable base price of ~$3/GJ or US$1.85/MMBtu (Billimoria et al., 2018). Australia's domestic market for natural gas – given the structural shortage – was in trouble (Simshauser and Nelson, 2015).

- **Coal Exit**

Throughout the 2007-2015 period when retail tariffs rose sharply, curiously, wholesale electricity prices were not (Rai and Nelson, 2020). Gradually rising levels of wind entering the market created a merit order effect (Csereklyei, Qu and Ancev, 2019; Rai and Nunn, 2020; Gonçalves and Menezes, 2022b, 2022a). Simultaneously, Australia's world-record take-up rates of rooftop solar PV were driving contractions in "grid-supplied" electricity demand (Simshauser, 2022b). Rising renewable supply, contracting grid-level demand and falling spot prices began to take their toll on marginal coal-fired generators (Nelson et al., 2022). From 2012-2017, eight coal-fired power stations totalling 5200MW exited (Nelson, 2018; Gonçalves and Menezes, 2022b).

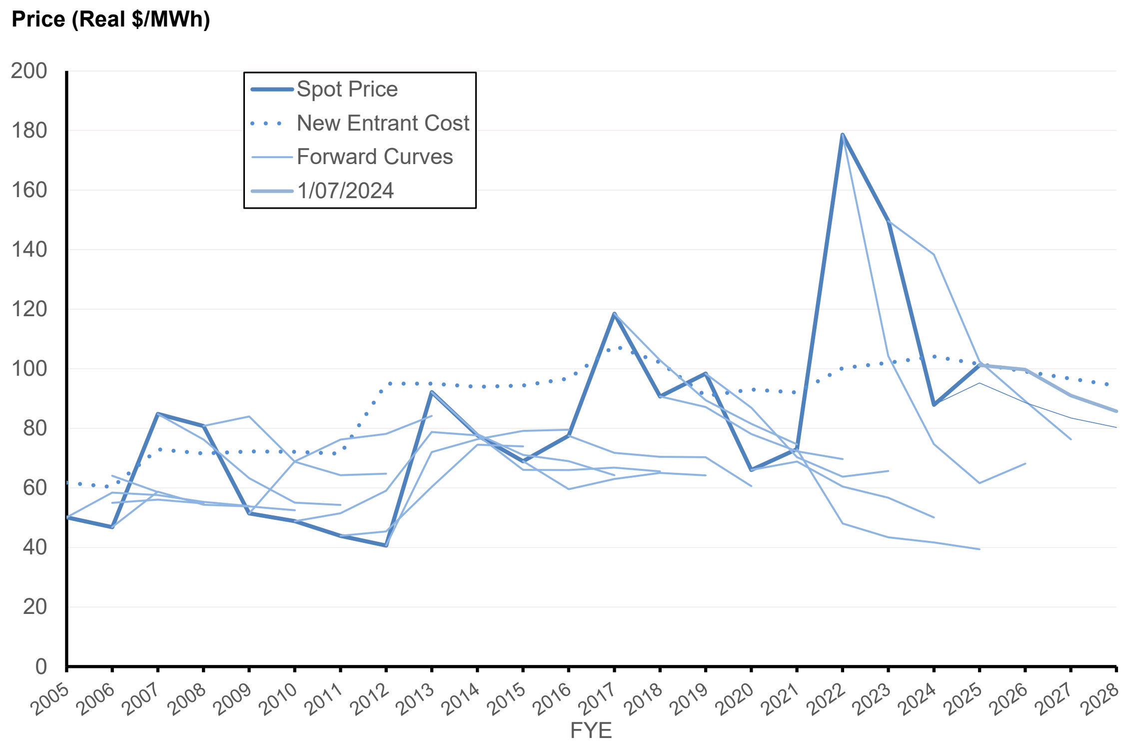
The marginal coal plant in each region faced a torturous 'prisoner's dilemma' decision set: (i) stay and lose money, or (ii) exit and prices rise for remaining coal generators in the post-exit environment.

[5] Specifically, from 1990-2006, year-on-year load growth in Queensland averaged 4.9% per annum.

History would show exit decisions dominated, with an average notice period of just 5.2 months from announcement to closure date (Simshauser and Gilmore, 2022).

If the NEM supply-side was functioning well, incumbent gas-fired generators would *'pick-up the slack'*. However, with a gas market experiencing structural shortages, the so-called transitional fuel was under-weight and consequently wholesale electricity prices more than doubled, particularly in the NEM's Victorian region during 2017-2019 (see Gonçalves and Menezes, 2022b, 2024). Wholesale electricity markets are first and foremost commodity markets, and as such both spot and forward prices are 'mean-reverting' (see Pindyck, 1999). When spot and forward prices rise above equilibrium levels, new plant enters. When prices fall well below equilibrium, plant exits. In either case, prices respond accordingly (see Fig.1).

Figure 1: Spot and 3-year Forward Curves (Queensland region, 2005-2025)



Source: Simshauser and Gilmore (2022)

Yet no sooner had spot prices stabilised when a series of severe coal plant outages *ricocheted* through the NEM (Nelson et al., 2023; Rangarajan et al., 2025). This coincided with a wet weather (el nino) year, meaning solar output was unusually low. Simultaneously, the Russia-Ukraine war erupted and roughly one third of Europe's gas supply was curtailed within a matter of weeks (Osička and Černoch, 2022; Rangarajan *et al.*, 2025). Continental European trade in natural gas was severely disrupted, which sent global LNG prices spiralling (Ah-Voun et al., 2024). As a major LNG exporter, this would flow through to Australian markets.

Australia's NEM – in 2005 widely documented as one of the world's better electricity market models (IEA, 2005) – completely malfunctioned in June 2022 (Biggar and Hesamzadeh, 2024; Rangarajan *et al.*, 2025). Trade in the NEM was suspended for six days, and in an extraordinary move, a $12/GJ (US$7.39/MMBtu) price cap was applied by the Commonwealth Government in order to stabilise the now malfunctioning domestic gas market (Pourkhanali *et al.*, 2024).

2.2 The shattering the political consensus on Australian energy policy

Historically, Australia's power systems were coordinated by state governments through to the start of the NEM in the late-1990s (Kellow, 1996; Rai and Nelson, 2020). As Havyatt (2022) explains, State Electricity Commissions in each NEM region can be traced as far back as the early 1900s. The first was the Hydro Electric Department in Tasmania in 1914 (renamed the Hydro Electric Commission in 1930), next was the State Electricity Commission of Victoria in 1918, the State Electricity Commission of Queensland would follow in 1938, the South Australian Electricity Commission was formed in 1943 (later renamed the Electricity Trust of South Australia) while the Electricity Commission of New South Wales was established in 1950 (Thomis, 1990; Kellow, 1996; Havyatt, 2022).

- **Public Administration of Electricity**

Public administration and overarching energy policy was the domain of state Governments, typically by an 'Energy and Resources Department' and a corresponding elected official appointed as portfolio Minister. Over time, each state built up considerable skill and expertise in its public administration of the sector. As Havyatt (2022) explains, that this expertise was housed inside statutory 'Commissions' was an artifact and invention of the State of Victoria – its prime purpose being to ensure public administration of power systems was one-step removed from politics.

Although the constitution is ambiguous about the division of powers vis-à-vis the electricity supply industry (Simshauser and Tiernan, 2019), it was clearly a state responsibility until at least 1998. Consequently, the Commonwealth public service, despite its vast expertise (particularly in the Commonwealth Treasury – see Lindquist and Tiernan, 2011; Wanna, 2011; Stone, 2019) – was remote and therefore under-skilled vis-à-vis power system planning, administration, investment, reliability management, pricing and recovery following disaster events. These skills were housed at the State-level.

From WWII through to the late-1990s, a broadly united view of energy policy existed in Australia (Booth, 2000). As Kellow (1996) and Havyatt (2022) explain, this long post-war cycle comprised rapidly rising aggregate final electricity demand, and an acceptance that economies of scale in power generation and high voltage transmission lines would deliver steadily declining retail electricity tariffs, and improved reliability of supply.

Elected officials left power system operation to engineers, who saw a future based on low-cost coal-fired generation, planned, built and operated by the State Electricity Commissions (Havyatt, 2022). Power system planning would rely on low-cost coal for base load duties, exploit hydroelectric schemes where feasible, with gas and distillate-fired combustion turbines undertaking peaking duties. In the northern states of Qld and NSW, aging coal plant would progress from base to intermediate duties as new plant arrived, destined for retirement as they slowly progressed down the generator merit order. In the southern states, gas-fired steam generators were designed to undertake intermediate duties (see Booth, 2000).

Throughout the 1970s and 1980s however, overly optimistic forecasts of long-range aggregate final electricity demand growth, encouraged by a Commonwealth Government convinced of an endless mining boom (Havyatt, 2022), and state-based political drivers linked to underwriting aluminium smelters (Kellow, 1996), would combine and lead to critical investment mistakes in retrospect (Simshauser, 2021a). By the 1980s, NSW had built so much baseload coal plant that the oversupply would take almost 20 years to clear (Simshauser, 2022a). Further, in Victoria excess baseload supply forced a Labor government to increase prices by 30+% and privatise half of the Loy Yang 'B' power station to avoid compounding State credit downgrades (Kellow, 1996).[6] During the 1980s, similar

[6] As one reviewer observed, Queensland was a notable exception having taken out options to defer new plant. Indeed, Booth (2000) documents this period in some detail described Queensland's 1998 entry into the NEM as moving from a *'silk purse to a sow's ear'*.

conditions existed throughout much of the western world because power systems had shown the same characteristics of relentless demand growth and the pursuit of economies of scale (see Christensen and Greene, 1976; Huettner and Landon, 1978; Pierce, 1984; Hoecker, 1987), with acute examples including Great Britain (Newbery, 2021) and various states in the USA (Schmalensee, 2021).

- **The National Electricity Market**

Australia's Productivity Commission undertook an inquiry and recommended establishing a National Electricity Market (Nelson et al., 2019; Rai and Nelson, 2020), with the policy architecture effectively drawn from the *Washington Consensus* – commercialisation of government electricity businesses, industrial reorganisation and disaggregation, market deregulation, and finally, privatisation. Despite obvious consequences for state governments via the loss of electricity sector control through a national reform, a united view on energy policy remained (Simshauser, 2021a). To orchestrate this sequence of reforms, agreement was required by all states and territories, and in a remarkable feat of cooperative federalism and microeconomic reform, agreement was achieved. Australia's NEM was thus established in the late-1990s, forming part of a worldwide program commencing in Chile, progressing to Great Britain, the Nordic countries, New Zealand, certain regions of the United States and Europe (Pollitt, 2004; Rai and Nelson, 2020; Newbery, 2021; Schmalensee, 2021).

- **Causes of energy policy discontinuity**

References to climate change policy in Australia can be traced at least as far back as 1990 but its implications for energy policy began to emerge in 1997 via the Kyoto Climate Talks and the associated Kyoto Protocol (Hurst, 2017). That same year, Australia's conservative Prime Minister (John Howard) in a landmark speech telegraphed policies comprising a 'Renewable Energy Target' (RET) and an 'Emissions Trading Scheme' (ETS) (Simshauser and Tiernan, 2019).

Evidently, by the late-1990s the science of climate change began to creep into energy policymaking (Crowley, 2017) – something the Commonwealth public service would quickly acquire considerable skill and expertise in. By 2000, Australia had legislated the world's first RET and commenced a formal policy cycle into an ETS (Simshauser and Tiernan, 2019).

But the ETS would become the first casualty of the political economy of climate policy – the then Commonwealth Government citing a lack of broad international participation (Hurst, 2017). Nonetheless, a clear marker had just been drawn – highlighting the limits to, and eventual demise of, subsequent coal-fired generation developments. It is now a matter of history that the NEM's last coal-fired generation investment commitment decision occured in Queensland in 2004. Both the 'Parer Review' and the 'Scales Review' of the NEM (and every Review ever since) would identify the disconnect between energy policy and climate policy (Nelson *et al.*, 2019; Havyatt, 2022).

By the late-2000s, the concept of carbon pricing and an ETS would shatter Australia's united and bipartisan approach to energy policymaking. Over the ~20 year period 1997-2019, eight separate policy cycles were initiated to establish an ETS or equivalent scheme, but each attempt was met with political failure (Simshauser and Tiernan, 2019) and frequently, a change in Prime Minister or party leader as a direct consequence (Crowley, 2017, 2021). Even the RET, a largely bipartisan policy introduced by the Howard Government, would be subjected to six separate reviews and was materially altered on three occasions (Nelson, 2015; Simshauser and Tiernan, 2019).

To generalise, in each episode support came from the social democratic Labor politicians (red team) and moderate Liberal and National Party politicians (blue team). Opposition came from conservative blue team members, and on one of the most important policy cycles, ironically, the Greens contributed to blocking an ETS at a critical juncture in an episode of *the perfect being the enemy of the good* (Buckman and Diesendorf, 2010; Nelson et al., 2010; Jones, 2014).

- **Navigating climate policy – *renewables will be cheaper***

For any Commonwealth or State Energy Minister, policy is all about timing (Simshauser, 2018). Energy policy must compete with all other critically important ministerial portfolios (e.g. health, education, transport etc) to secure 'real estate' on the chronically congested cabinet diary (see Tiernan and Burke, 2002; Peters, 2005) – hence the phrase '*don't waste a good crisis*'.

In a cost of living crisis – which in Australia is principally a problem of rising interest rates and housing costs (18% of disposable income), food and beverages (16.5% of incomes) and transport (15% of incomes) – a narrative of lower electricity bills (3% of incomes) through more renewable energy presents as careful policymaking. Specifically, a renewable policy energy architecture by default enshrines both energy and climate objectives in a manner that *prima facie* meets the energy trilemma – reliability, affordability and sustainability (Dodd and Nelson, 2019) .

Prising open a political window of opportunity explains much of the large shifts in contemporary energy market policymaking (Jones, 2014; DeLeo, 2018; Simshauser, 2018). Two issues typically combine to create the policy window – rising prices and the cost of living crisis. By 2019, the cost of new entrant renewables (i.e. wind and solar) in Australia had clearly fallen below the running costs of marginal coal and gas plants (Simshauser and Gilmore, 2022). Combined, these factors led political leaders from both sides of politics to originate policy arguing that renewables would be cheaper, usually expressed as lower household electricity bills, lower wholesale prices, or both (see NSW Government 2020; Queensland Government, 2022; Victorian Government, 2022, 2024). In aggregate, it would seem the fractured nature of the climate policy debate and the shattering of political consensus on energy policy made the promise of *'renewables delivering cheaper bills'* a politically necessary precondition, and imperative, for voter acceptance.

The opposing political view (i.e. blue team conservatives) in Australia identifies the obvious problems associated with wind and solar – its intermittency (Rangarajan *et al.*, 2025), inter-seasonal volatility (Chyong *et al.*, 2024) and the empirical observation that Australia's wholesale and retail electricity prices have risen sharply (Biggar and Hesamzadeh, 2024). Ergo, they argue the evidence is that the pursuit of renewables is ill-founded and by implication, climate policy objectives should on balance be relegated.

Blue team conservatives have a nuanced position, however. Conservatives accept some ongoing level of renewable investments will, and should, continue – especially rooftop solar PV – and that in the long run, Australia's climate commitments may best be met through development of some other dispatchable technology (e.g. possibly nuclear), and extending the life of the existing thermal fleet is required during any interim period.

Noting the following is an *ex cathedra statement*, in our professional experience sophisticated consumer groups have formed a view that renewables are not cheaper, that they involve higher cost and political parties should simply come clean and say as much – all the while noting it is the correct policy setting given climate science and Australia's commitment to Net Zero by 2050. This is also the view of Editors at the Australian Financial Review[7] – one of the more respected mastheads vis-à-vis reporting of the energy industry.

So are renewables cheaper? To examine this, it is necessary to analyse *the counterfactual scenario*.

[7] See Energy transition: Honesty about wind and gas is best policy

3. Models and Data

Our approach to modelling identifies generation costs and prices with a focus on the NEM region of Queensland due to its abundance of all resources, viz. coal, gas, wind, solar and pumped hydro site resources. We reconstruct historic 30-minute demand-side data from 2024 from first principles, i.e. aggregate final electricity demand comprising both grid-supplied power and self-consumed rooftop solar PV. This enables us to isolate the impacts of all technologies in what was an unusually low wind year. In all electricity market model simulations, we apply an own-price elasticity estimate of -0.08 which is broadly consistent with Burke and Abayasekara (2018), Sergici et al., (2020) and Simshauser (2022b) while for natural gas, we use an own-price elasticity estimate of
-0.18 based on the results in Li et al., (2022).

3.1 Models

On the supply-side, we rely on three sequential models:

1. Our *Project and Corporate Finance Model* (PCF Model) produces commercial-grade unit cost estimates of any given generation technology. A complete catalogue of plant capital costs and capital markets data (including credit spreads and credit metrics) exists within the model spanning the period 2000-2025. Program outputs resemble Levelised Cost of Electricity results, but the PCF Model takes estimates one step further by internalising and co-optimising project or corporate finance, gearing and taxation variables in order to identify the minimum post-tax, post-finance generalised unit cost. Model logic appears in Appendix I. Results from this model are used as inputs in our NEMESYS Model.

2. Our *Gas Partial Equilibrium Model* (GPE Model) is a time-sequential, dynamic co-optimisation model of Australia's eastern gas network. Grounded firmly in welfare economics, it seeks to maximise the sum of producer and consumer surplus under competitive market conditions by replicating all major gas fields, gas transmission pipelines and major storages. The gas demand segments of residential and industrial loads, gas-fired generation, LNG imports and export are discretely defined at a nodal level at daily resolution. GPE Model logic and pipeline architecture appear in Appendix II. Results from this model are used as inputs to the PCF Model, and in turn, our NEMESYS Model.

3. Our electricity market model (NEMESYS) is a dynamic, time-sequential, partial equilibrium model comprising a security-constrained unit commitment engine with half-hourly resolution and price formation based on the NEM's uniform, first-price auction clearing mechanism. As with Bushnell (2010), the model co-optimises the generation fleet under conditions of perfect competition, entry and exit. Perfect entry and exit means the model is free to install any combination of (indivisible) thermal plant capacity and (divisible) renewable and storage plant capacity that satisfies differentiable equilibrium conditions. Investment and unit commitment occurs within a lossless two-zone network setup (i.e. North Qld and Central-South Qld). And as with Hirth, (2013), half-hour resolution modelling over a single reporting year forms the focus of results. Model logic appears in Appendix III. This model analyses our renewable and our counterfactual scenarios.

Our approach to modelling is to utilise 2024 demand data (and associated elasticity coefficients) and contemporary generator costs under conditions of perfect entry and exit, and the fundamental microeconomics principle of Walrasian equilibrium (see Arrow and Debreu, 1954) – a condition which, as Newbery (2022) explains, exists in electricity markets in a way almost unseen in other markets. That is, we are seeking to define marginal costs and prices. Doing so reflects current market conventions but also allows us to consider the entire plant stock as seamlessly fungible (i.e. without development or construction lags).

3.2 PCF Model data

Of critical importance to our modelling sequence are assumed plant costs, outlined in Tab.1. This includes the renewable and firming fleet, and thermal plant.

Table 1: Plant entry cost parameters

Table 1A - Renewable Fleet		Wind	Solar	Battery	Pumped Hydro	OCGT
Project Capacity	(MW)	500	400	200	2,000	250
- Storage Capacity	(Hrs)	-	-	4	24	-
Overnight Capital Cost	($/kW)	3,000	1,500	525	2,525	1,421
- Storage	($/kWh)	-	-	370	83**	100
- Contingency		10%	-	-	33%	-
Plant Capital Cost	($ M)	1,650	600	401	12,007	380
Operating Life	(Yrs)	35	30	20	100	35
Annual Capacity Factor	(%)	33-43%	21-27%	14.7%	18.0%	5%
Transmission Loss Factor	(MLF)	0.980	0.970	1.000	1.000	1.000
Transmission REZ Costs	($/MW/a)	25,000	12,500			
Fixed O&M	($/MW/a)	50,000	20,000	10,000	20,000	1,000
Variable O&M	($/MWh)	0.0	0.0	0.0	1.0	8.0
FCAS	(% Rev)	-1.0%	-1.0%	4.0%	10.0%	2.5%

Table 1B - Thermal Fleet		Sunk Coal	New Coal	CCGT	OCGT	Sunk P-Hydro
Project Capacity	(MW)	1,400	800	375	250	500
- Storage Capacity	(Hrs)	-	-	-	-	14
Overnight Capital Cost	($/kW)	1,000	5,616	1,221	1,421	1,000
- Contingency/Linepack		n/a	0.0%	200	100	n/a
Plant Capital Cost	($ M)	1,400	4,493	533	380	500
Operating Life	(Yrs)	10	40	35	35	60
Annual Capacity Factor	(%)	50-87%	50-87%	30-65%	2-10%	11.0%
Transmission Loss Factor	(MLF)	0.970	0.970	0.970	1.000	1.000
Unit Fuel Cost	($/GJ)	4.00	4.00	12.00	16.49	-
Heat Rate/Cycle Efficiency	(kJ/kWh)	10,000	9,231	7,059	10,000	78%***
Fixed O&M	($/MW/a)	93,000	50,000	20,000	10,000	20,000
Variable O&M	($/MWh)	5.0	1.0	5.0	9.7	0.0
FCAS	(% Rev)	5.0%	5.0%	5.0%	2.5%	10.0%

** Gas pipeine. *** Round trip

Source: Aurora 2025, CSIRO GenCost 2024.

The capital markets data used in the model appears in Tab.A1 (Appendix I) and includes underlying borrowing rates, credit spreads, credit covenants and expected equity returns for project and corporate (i.e. on-balance sheet) financings.

3.3 Gas Model Data

Critical inputs to the GPE Model are the pipeline network (Fig.2), aggregate demand (Fig.3) and the aggregate supply function (Fig.4). All gas transmission pipelines, lengths, connections, capacity (TJ/d) and tariffs ($/GJ) appear in Appendix II along with model logic.

Figure 2: GPE Model demand centres, gas fields and pipelines

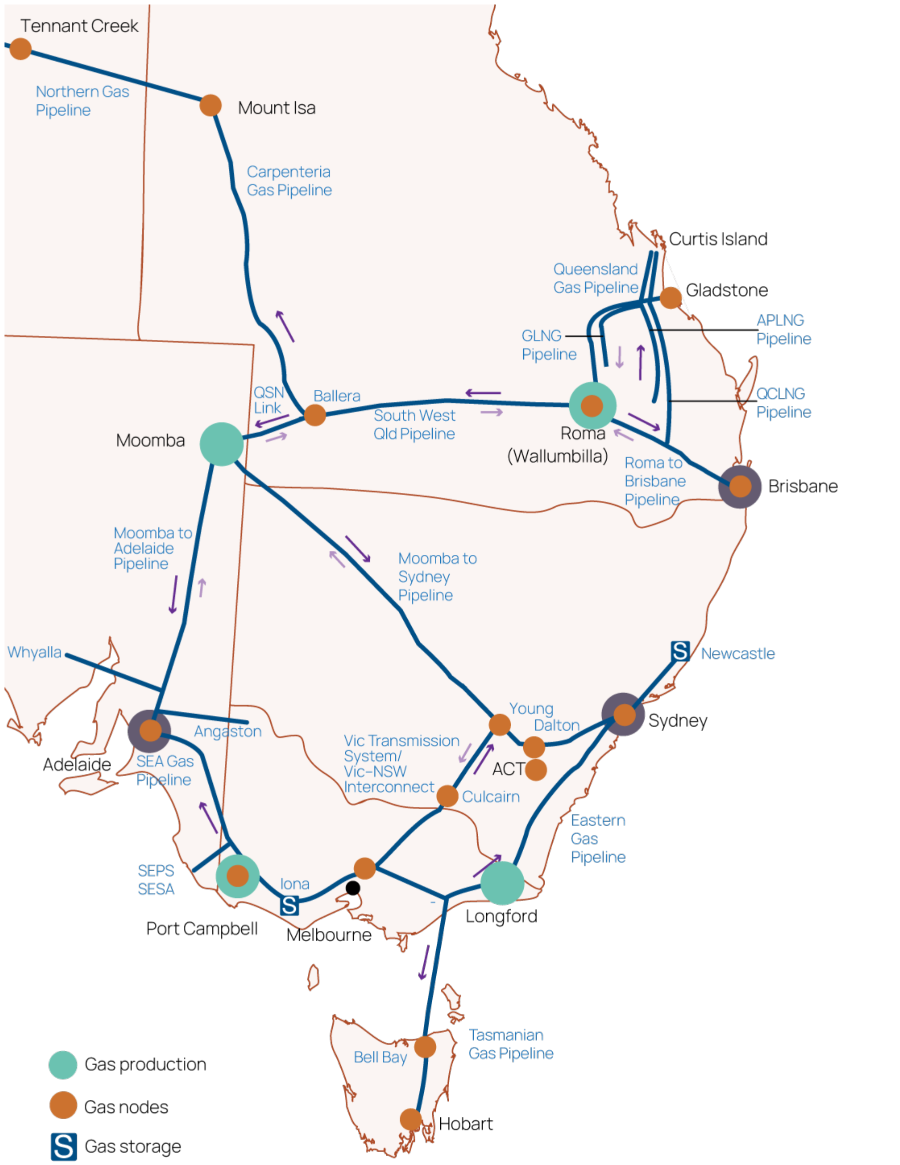
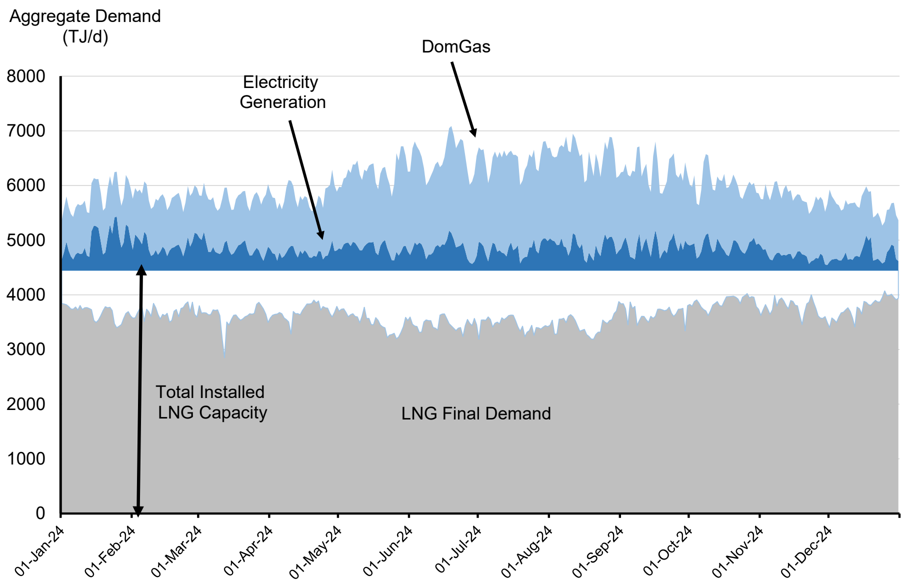
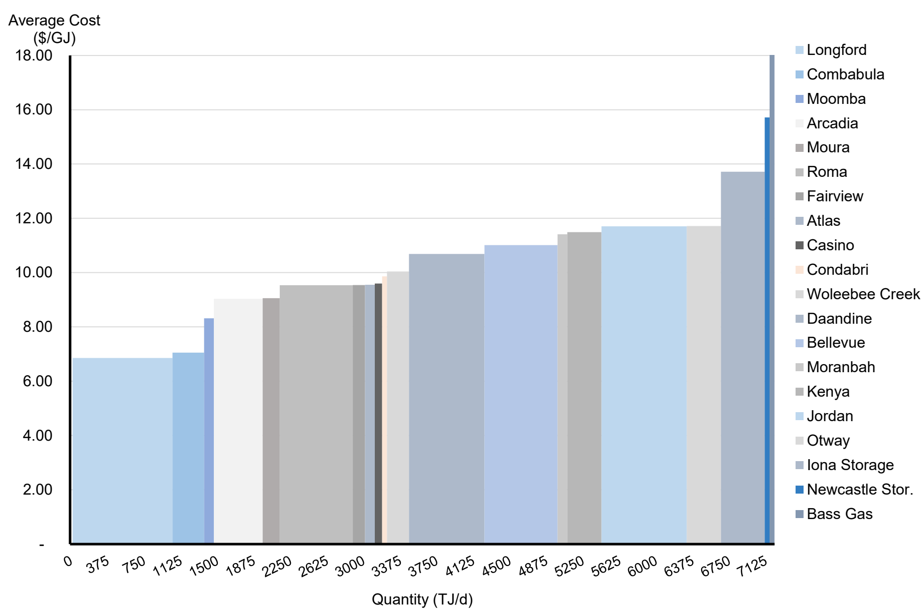


Figure 3: Easten Australian aggregate gas demand (daily resolution)



Source: GMAT.

Figure 4: Easten Australian aggregate gas supply (daily resolution)

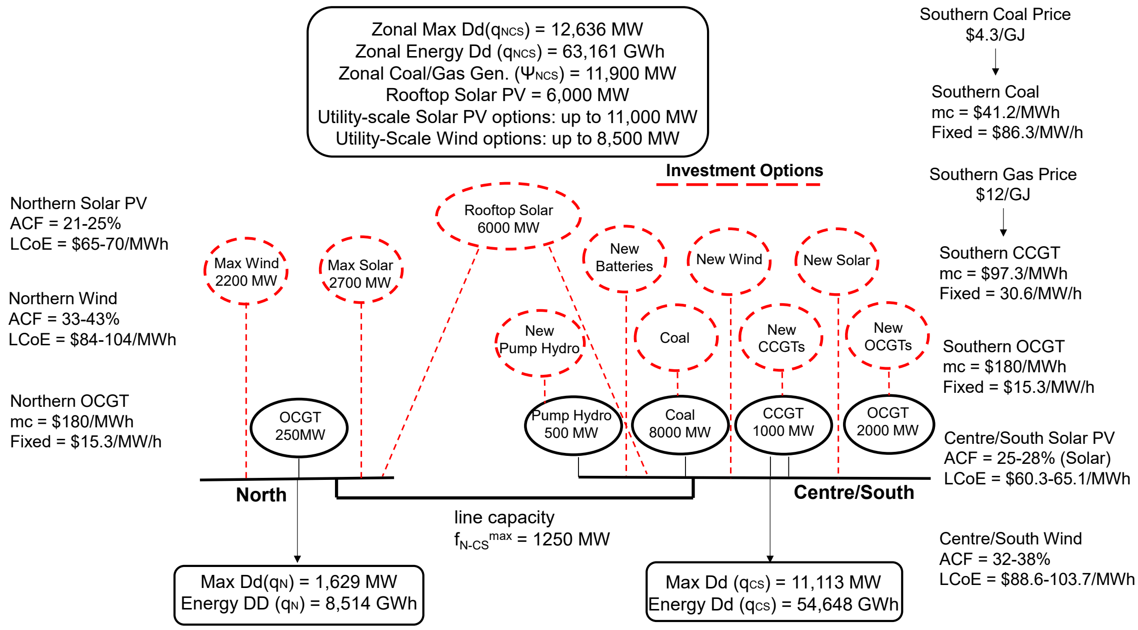


Source: Simshauser & Gilmore (2025)

3.4 NEMESYS Model data

Results from the PCF and GPE Models form critical (iterative) inputs to the NEMESYS Model, along with 30-minute aggregate demand data and chronologically matched wind and solar traces from 10 different locations across southern, central, north and far north Queensland. The NEMESYS Model setup is illustrated in Fig.5, which includes details of aggregate supply with new entrant options represented by dashed circles. Note high quality northern renewables will be constrained by intraregional line transfer limits $\left(F_{N-CS^{Max}}\right)$. The top box in Fig.5 depicts aggregate final energy demand (63,161GWh) and maximum demand (12,636MW), which included self-consumed PV production.

Figure 5: NEMESYS Model Setup



4. Results

In the analysis which follows, we start by casting our modelling suite back to the mid-2000s to identify benchmark power costs. From there, we shift back to current 2025 costs and prices and examine a counterfactual scenario.

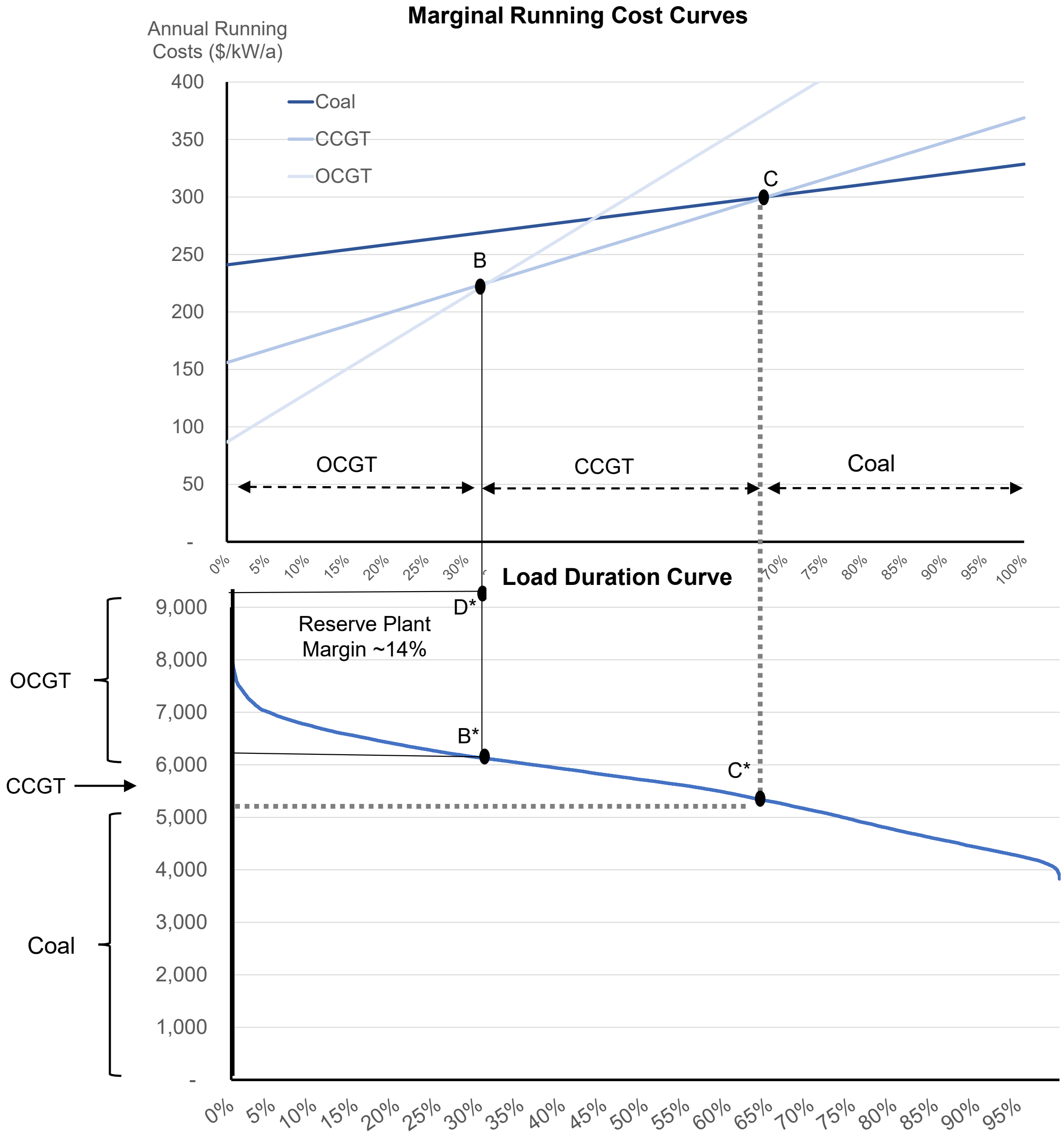
4.1 *Good old days: the 2005 scenario and $40 prices*

We noted earlier that during the mid-2000s, the NEM was widely considered the gold standard for an electricity market reform (see IEA, 2005) with Australian households enjoying the second lowest cost electricity tariffs in the world (MED, 2007). What was the underpinning wholesale market setup that delivered such outcomes? To summarise, an energy-only gross pool market with a very high market price cap and a liquid forward market, set within a large thermal system where the optimal plant mix collapsed down to baseload coal, intermediate Combined Cycle Gas Turbines (CCGT) and peaking Open Cycle Gas Turbines (OCGT) as the benchmark technologies. Fig.6 illustrates this via Berrie's (1967) classic partial equilibrium framework.

The top chart in Fig.6 depicts the annual running cost curves of the three plant technologies – characterised by low-cost $1/GJ (US$0.65/MMBtu) black coal and $3/GJ (US$1.85/MMBtu) natural gas. Under these conditions, for any output level (measured by the x-axis) up to ~30% utilisation (i.e. peaking duties), the OCGT exhibits the lowest annual cost. For intermediate duties spanning ~30-65% utilisation, CCGTs formed the benchmark technology. For baseload operations, coal was the lowest cost.

The efficiency points in this top chart are transposed to the lower chart – which depicts Queensland's 2005 load duration curve. It can be seen that with perfect plant availability, ~5250MW of base plant is required (and as dynamic power system modelling reveals, about 6000MW when scheduled and forced outages are accounted for). For intermediate duties, ~1000MW of CCGT plant is required, and in aggregate, around 9500MW is required including a reserve plant margin of ~14% under PoE50 summer conditions.

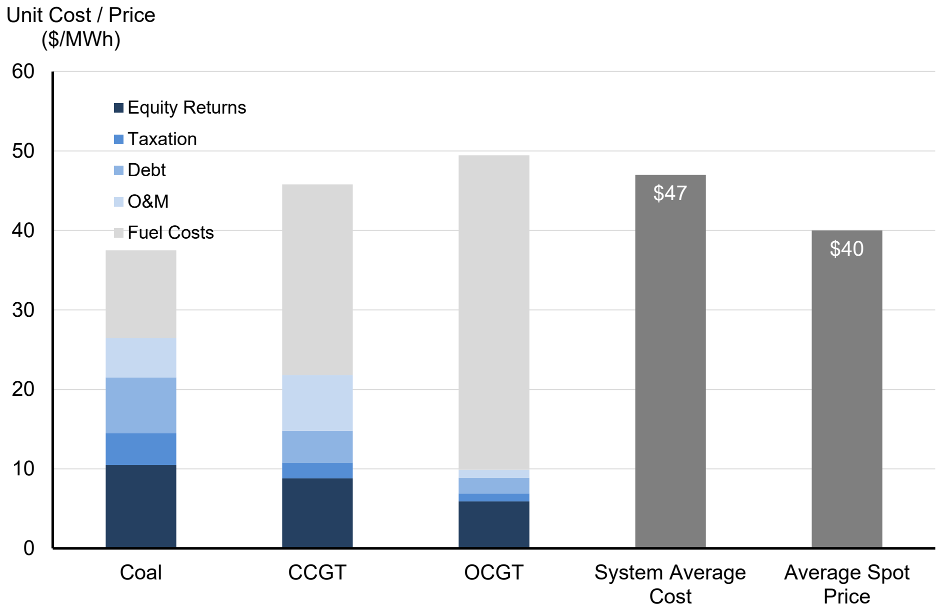
Figure 6: Static Partial Equilibrium – Queensland 2005



Average Total Cost of the three generation technologies, and for the overall Queensland power system under dynamic modelled conditions is illustrated in Fig.7. Notice the rich blend of fixed (blue bar segments) and variable (grey segment) costs of the generation technologies. This blend is emphasized by the intercepts (fixed) and slopes (variable) of the annual running cost curves in the top graphic of Fig.6.

The final two bars in Fig.7 show system average costs and prices for the 2005 year arising from our NEMESYS Model. System cost in equilibrium is ~$47/MWh while the time-weighted (baseload) spot price is ~$40/MWh or US$26/MWh (in 2005 dollars). The volume-weighted spot price is ~$43/MWh and the difference between the $47/MWh unit cost and $43/MWh price, in equilibrium, is covered by contract premiums in forward markets, given risk-neutral and risk-averse energy retailers, and the then very high market price cap of $10,000/MWh.

Figure 7: 2005 Scenario - Queensland plant, system costs and baseload price



4.2 The 2025 *'counterfactual scenario'*

In 2025, the benchmark plant portfolio has transitioned. In Queensland – which has the world's highest take-up rate of rooftop solar PV – net grid-level demand is rapidly de-basing the role of inflexible, baseload coal plant. Specifically, daytime grid-supplied load is reducing sharply in both absolute and relative terms. Continuous entry of utility-scale solar plants is further de-basing baseload duties, and in turn collectively produce an extraordinary number of negative price events – currently more than 1000h pa (out of 8760h pa). Negative prices cannot be easily hedged away because NEM convention is that forward contracts settle with a zero price floor. This is economically damaging to inflexible baseload coal plant, and of great benefit to flexible and storage plant. By the late-2020s, surplus rooftop solar PV is expected to produce episodes of intractable dispatch for the marginal coal plants – there will literally be no physical market demand for their minimum generation output for hundreds of hours per annum (see Simshauser and Wild, 2025).

Australia's energy transition thus involves a shift from base, intermediate and peaking assets to an entirely different asset allocation, viz. 'energy' and 'firming'. **Energy** is the domain of aging coal plant and the new energy-producing entrants – wind, utility-scale solar and rooftop solar. Introducing intermittency and the progressive loss of aging coal plant creates a requirement for **Firming** duties. Firming duties are undertaken by remnant coal plant, new entrant batteries, pumped hydro – and, of utmost importance – existing and new gas turbines as the power system's *last line of defence*.

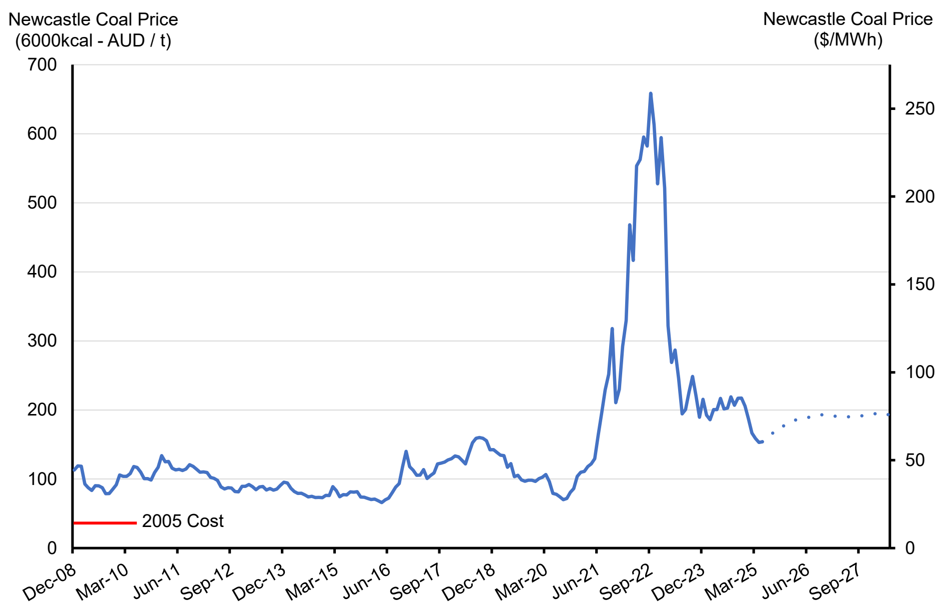
Australia's transition *has itself* transitioned. From 2000-2018, wind and solar entry in the NEM was *policy-driven* through Australia's 20% RET and its associated renewable subsidies (i.e. renewable certificates). Throughout this 19-year period, 125 renewable projects totalling 11,400MW reached financial close, representing capital investment of $31.8 billion (Simshauser and Gilmore, 2022). By the end of 2018, the RET was thought to be fully subscribed.

From 2019-2025, with little additional (*or effective*) policy priming, 105 renewable projects totalling 19,300MW reached financial close in the NEM at a capital value of $40.1 billion. A small component of these irreversible renewable project commitments were underwritten by State (~2500MW) or Commonwealth Government (~500MW) CfDs. The overwhelming majority (i.e. 16+GW) were committed through on-market transactions, driven by capital markets, supply chain pressures and corporate PPAs.

Were these transactions driven by ESG considerations, or economics? To answer this query, we must examine a counterfactual scenario – a reversion to coal or natural gas as the new entrants to meet demand growth and replace exiting coal plant. Before proceeding, it is first helpful to examine the evolution of market prices for coal and natural gas, in Fig.8-9.

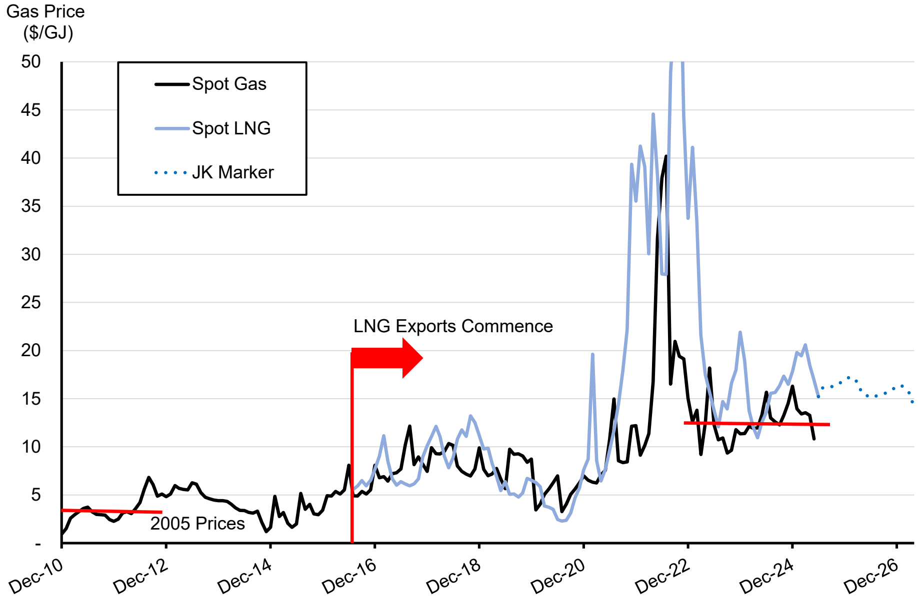
In Fig.8, it can be seen that the price of coal is now ~8x the value of legacy long-dated coal supply contracts that existed in the mid-2000s. Export coal is of a high quality and domestic supply is typically lower grade, and at times may be ~25% lower cost. Even with such a discount applied, coal prices have clearly increased very significantly.

Figure 8: Coal prices (2008 – 2028, 6000kcal Futures)



Similar conditions exist in the market for natural gas, as Fig.9 reveals. The price of natural gas has increased by a factor of 4, largely driven by international dynamics and a structural shortage as outlined in Section 2.

Figure 9: Domestic and export gas prices (2010-2025, Japan-Korea Marker)



In Fig. 10, we re-cast the entry costs of coal, CCGT and OCGT plant as at '2005' (first bar series), then escalate these data through to 2025 dollars ('2005 Esc.' – second bar series) using the consumer price index, and finally, contrast these historical data points with contemporary '2025' cost estimates (third bar series).

Figure 10: Unit cost comparison 2005 vs 2025

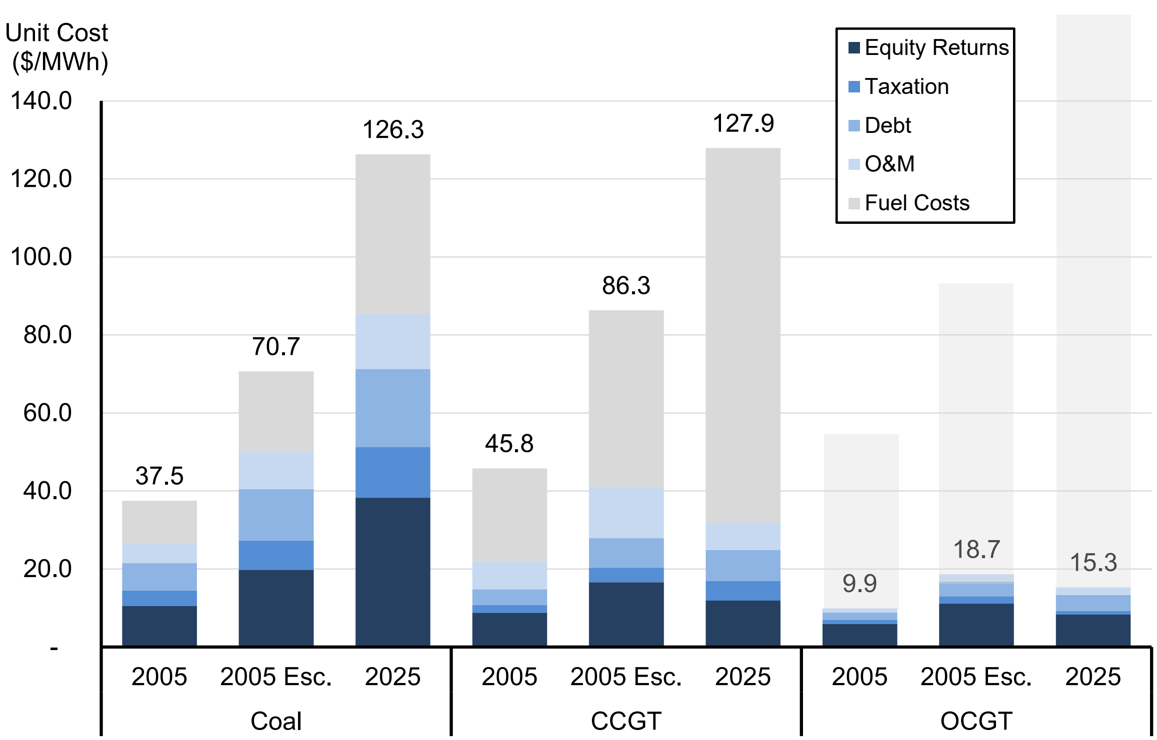


Fig.10 reveals a striking set of results. Our '2025' results bear little resemblance to '2005 Esc' scenario results, that is, 2005 results escalated at the cumulative consumer price index over the period 2005-2025. So why have 2025 thermal plant costs increased so materially? The first point to note is that we use a unit cost of coal of $4.0/GJ which is 50%[8] below (i.e. not 25% below) the export price in Fig.9. Yet even at this level, it is more than double the escalated 2005 result of $1.9/GJ. A similar pattern can be seen with natural gas – $12/GJ is more than double the escalated 2005 result of $5.7/GJ. And to be clear, if CCGTs are deployed as the new baseload fleet, our GPE Model results suggest gas prices would rise to ~$12.7/GJ.

Looking at capital equipment, the cost of gas-fired generation plant has risen broadly in line with inflation. But the capital cost of coal plant, at $5016/kW, is multiples of historic construction costs given a requirement for ultra-super-critical technology (entailing higher temperatures, higher steam pressures and more exotic metals), elevated construction costs outlined earlier, and tighter environmental conditions for new developments.

The cost of capital for coal and gas-fired generators is a complex topic. How capital markets would respond, and price, debt and equity raisings necessary to finance a new coal plant in the current environment is unknown. We scraped data from the US s144A bond market for utilities with and without (sunk) coal-fired generation portfolios. *Prima facie*, these data implied a ~50bps spread for portfolios comprising aging coal assets.

Building a new coal plant, we suspect, would face materially higher premia due to the credit time horizon problem (see Offer, 2018). In Simshauser and Nelson (2012), Australian project bankers were surveyed on views relating to debt premia for incumbent baseload coal and gas generators under conditions of an acute episode of carbon policy uncertainty. The survey data revealed the following results:

- Coal credit spreads: +150-200 basis points
- Gas credit spreads: +100-150 basis points

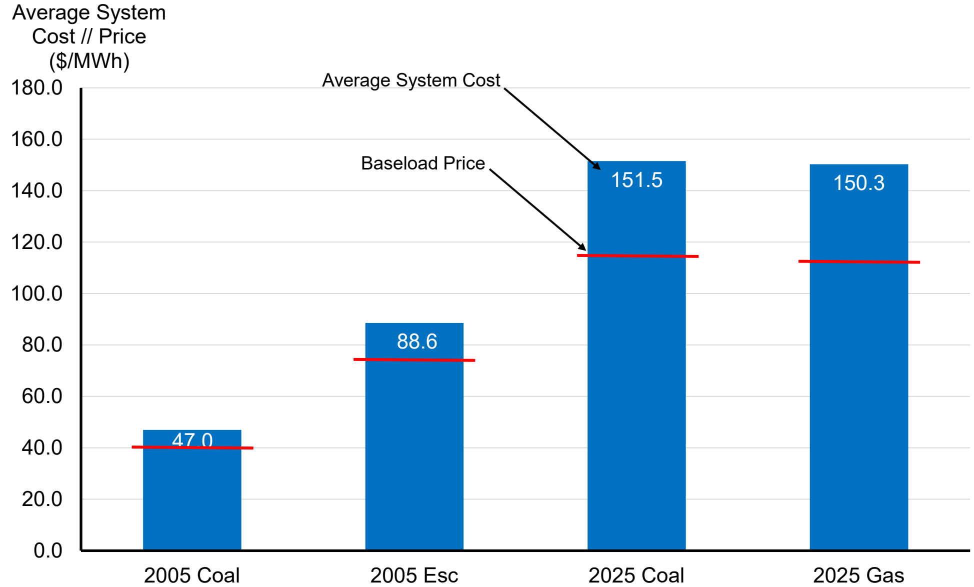
We have opted to select the mid-point from the above for new entrant coal (175bps) and CCGT plant (125bps) and added these premia to expected debt and equity returns. While this likely *understates* outcomes of bond and equity raisings for new coal or baseload CCGT plant, it at least places *a* marker on the existence of a premium.

Conversely, we do not place any premium on OCGTs given their crucial role in transitioning power systems. Capital markets may well have idealised views of what low risk electricity investments are. But economic gravity, the laws of physics, power system engineering requirements and the political economy of reliability will invariably reveal the essential role that gas turbines will play in a transitioned plant stock (Simshauser and Gilmore, 2024).

When the results in Fig.10 are migrated to our NEMESYS (power) and GPE (gas) system models, we find Walrasian unit costs and clearing prices in the counterfactual scenario at substantially higher levels than our escalated 2005 benchmark, as illustrated in Fig.11.

[8] We assume an otherwise stranded resource.

Figure 11: ***The counterfactual scenario* - power system cost / price**



Working from left to right, the first bar in Fig.11 replicates our 2005 simulation. When these data are escalated into constant 2025 dollars, system average cost is $88.6/MWh and baseload prices are ~$76/MWh. The remaining two bars represent our 'counterfactual' scenarios simulated in NEMESYS. The '2025 Coal' and '2025 Gas' scenarios assume 0% renewables.

The first point to note from these *counterfactual scenarios* is that they all exhibit materially higher system costs and prices. This is being driven by our entry cost estimates in Fig.10. By implication, if our Fig.10 estimates were too high, then Fig.11 results would move down (and vice versa).

In aggregate, our counterfactual scenarios present sobering results. Outcomes are overwhelmed by elevated coal ($4/GJ) and plant (ultra super critical coal) equipment costs (~$5016/kW), or gas costs ($12.7/GJ).

5. Are renewables cheaper?

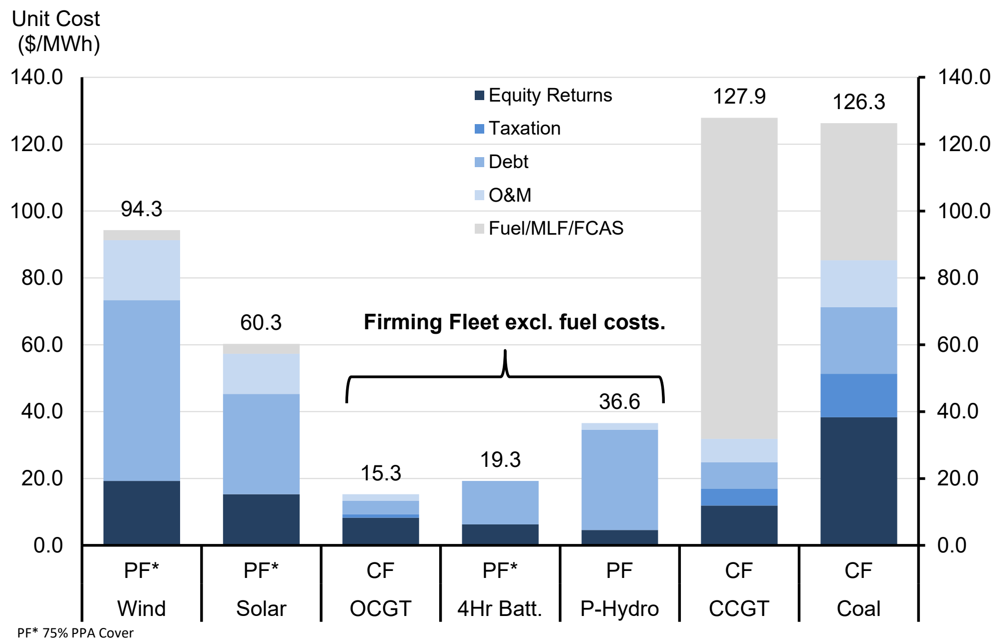
In our final scenario, we introduce renewables and storage options to the model, along with incumbent coal and gas plant. The model is free to select new coal and gas plant and as optimisation results subsequently reveal, OCGT feature prominently. Coal and CCGT do not – their portfolio weightings reduce.

Our PCF Model makes use of the data in Tab.1 to produce generalised entry costs for renewables and the firming fleet. Point estimates are illustrated in Fig.12. Wind is $94.3/MWh although when applied in the power system model across multiple sites, entry costs span $85-104/MWh as highlighted in Fig.5. Similarly for solar, our benchmark plant is $60.3/MWh with sites ranging from $60-70/MWh.

To utilise these intermittent resources, an adequate 'firming fleet' is required to ensure the power system balances in each trading interval. The firming fleet may include incumbent coal and gas plant, new coal, CCGT, OCGT, batteries and pumped hydro. This array of plants and their unit costs as made available to our power system model are illustrated in Fig.12.

For clarity, we assume wind, solar and batteries have been Project Financed (PF*) and structured with an assumed 75% (run-of-plant) PPA with 25% merchant exposure – currently the dominant model in the NEM (see Gohdes et al., 2022, 2023; Gohdes, 2023; Flottmann et al., 2024). Pumped hydro is also a PF but with 100% PPA coverage. All thermal plant is assumed as conventional corporate financings (CF) with BBB credit metrics. Note OCGT, Battery and Pumped Hydro plant are expressed by their 'carrying cost' expressed as $ per MW per Hr (i.e. regardless of their capacity factor)[9].

Figure 12: Generalised average total cost of generation plant in Qld



When these data are made available to our power system model, NEMESYS seeks to minimise costs by retaining viable (albeit aging) incumbent coal plant, and then deploys an array of wind, solar (utility and rooftop), batteries, pumped hydro and OCGT plant to satisfy aggregate final electricity demand of 63,400GWh (and maximum demand of 12,600MW) subject to a 50% renewable constraint (reflecting where the Qld power system is trending towards given existing, committed and near-committed projects). Results are illustrated in Fig.13. Working from left to right, bars 1-4 have been reproduced from Fig.11 for ease of comparison, with the final bar representing the 50% renewable scenario.

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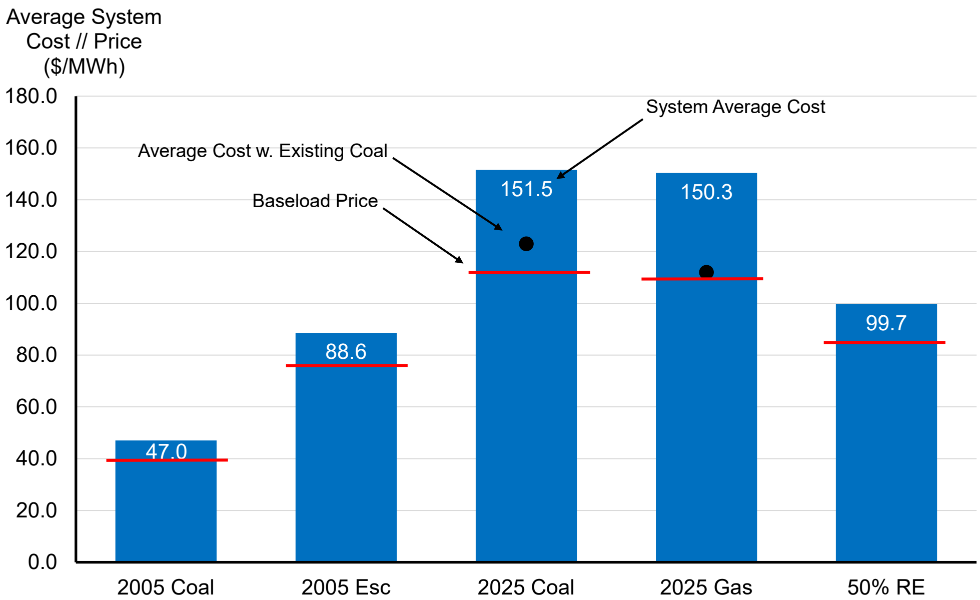
[9] Pumping costs for hydro, and charging costs for batteries, are an outcome of dynamic system modelling. To generalise, pumping/charging costs fall as solar market shares rise, whereas their generation dispatch prices tend to rise as coal plant exits.

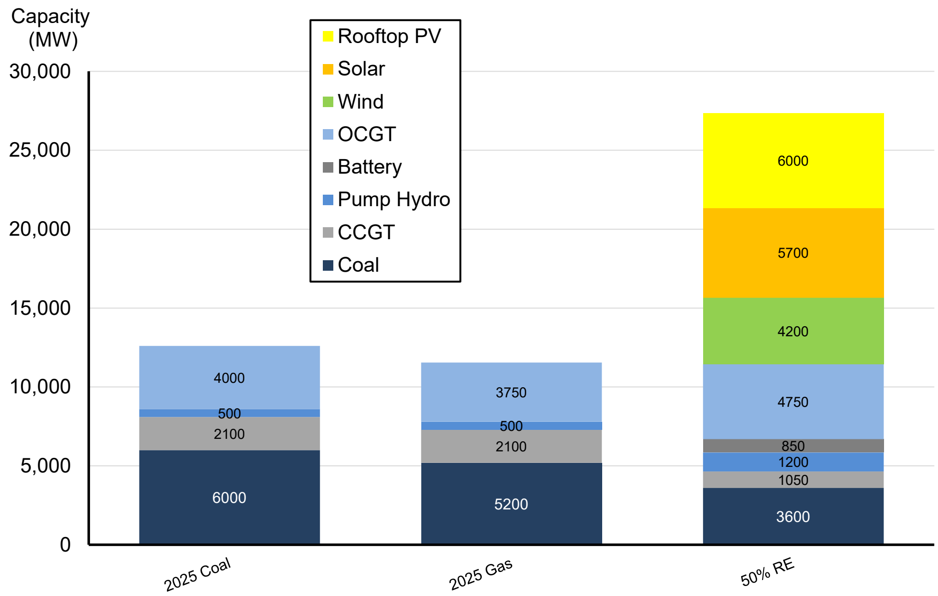
Figure 13: Counterfactual scenario v renewable scenario



With Fig.13, the first point to note is that our '50% RE' scenario exhibits higher costs and prices than our '2005 Esc' scenario, that is, our *$40 market* escalated at CPI to 2025 dollars. In this sense, consumer groups and critics of renewable policies are correct. Given current development costs, **renewables are *not lower cost* than our old power system**. However, it is worth noting that when the various governments (NSW, Queensland, Victoria, Commonwealth) from both sides of the political divide made policy announcements suggesting renewables would be cheaper, *at that time (*up to ~2022), they had reasonable grounds for saying so. However, the unit cost of wind (and while not illustrated here, transmission network augmentations) have more than doubled over the past five years after having fallen over the previous ~20 years (see Appendix IV). If we substitute our $90+/MWh entry cost for wind with a $60/MWh entry cost, power system costs broadly calibrate to our '2005 Esc' scenario. It is noteworthy that in 2019, wind PPAs were clearing well below $60, viz. ~$45-55/MWh.

Regardless, what can be said of the Fig.13 results is that the '50% RE' scenario exhibits lower costs and prices than our *counterfactual scenarios*. Furthermore, the '50 RE' scenario has significantly higher aggregate final electricity demand than the counterfactuals because equilibrium power system costs and prices largely mirror existing prices. Consequently, demand elasticity effects are negligible. Aggregate supply underpinning the various scenarios in Fig.13 are illustrated in Fig.14 with scenario data provided in Appendix V.

Figure 14: Counterfactual and RE plant stock



6. Incumbent coal plant: age and reliability effects

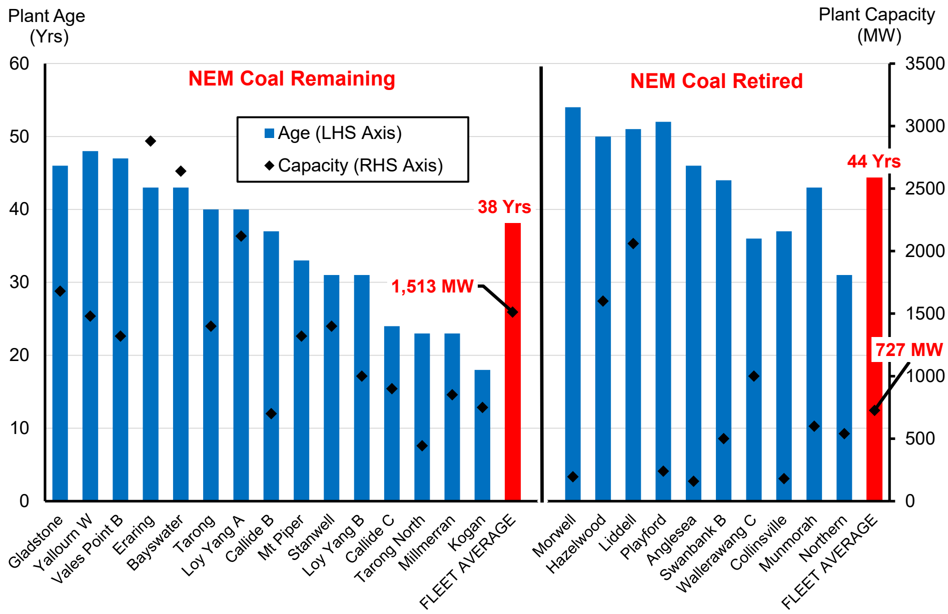
In our modelling suite, many incumbent coal plants are low cost given the absence of a price on CO_2 externalities. As they exit, the unit cost and price of electricity will gradually rise. There are exceptions to the rule, however. Certain black coal power stations in the NEM are exposed to export coal for marginal, or all, of their fuel supply. These *are not* low cost options for the model. They form key targets for wind, solar and storage entry – and in turn, marginal coal plant exit. This aspect of the energy transition meets any political economy constraint vis-à-vis electricity prices and is unambiguously welfare enhancing. Around 2400MW of incumbent coal in Queensland will fit into this category between now and 2030, and a further ~3000MW in NSW.

From a climate science perspective, coal plant should be closed as soon as possible and be replaced by renewables. From a political economy perspective, reliability of supply must always be assured, and prices must follow a stable trajectory. Furthermore, community, biodiversity and cultural/heritage constraints must be navigated. The energy transition thus entails quite a balancing act for Energy Ministers.

In a mature debate, it is to be acknowledged that low-cost incumbent coal plants face exit speed limits in navigating the political economy of the 'pricing' and 'reliability' constraints of energy policy. New wind and solar also face entry frictions due to the 'quadlemma' (which extends the energy trilemma into include 'community' constraints).

Yet incumbent coal plants face speed limits. Fig.15 presents the NEM's coal fleet in two distinct portfolios. The left panel comprises the NEM's existing 20GW coal fleet, spread across 15 power stations. The right panel comprises the 10 coal plants which have already exited. Note the average age of the retired fleet is 44 years, and average exit capacity was 727MW. NEM coal plant exits have thus far been highly disruptive (see Nelson, 2018; Simshauser and Gilmore, 2022; Gonçalves and Menezes, 2022b). The remaining fleet has an average age of 38 years and average capacity of ~1500MW. With an average exit age of 44 years and an average incumbent age of 38 years, this suggests transitional planning is required now in Central Queensland, Victoria's La Trobe Valley, and in NSW.

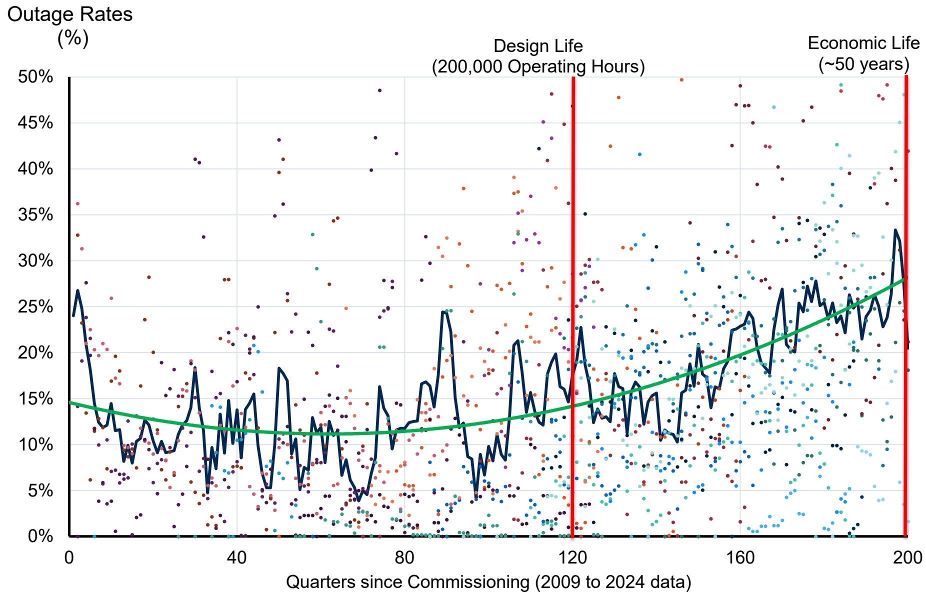
Figure 15: Coal fleet age and capacity



Where aging low-cost coal plant become a vulnerability for the power system is via their *outage rates*. To summarise, coal plant must undertake routine statutory overhauls to maintain pressure vessels and other critical components. As plants age, they are evidently subject to rising unplanned outage rates due to equipment fatigue. The world benchmark for coal plant availability was set by Queensland power stations, viz. Stanwell and Tarong at ~94% availability.[10] These two plants still exhibit benchmark performance in spite of their age. But axiomatically, as a fleet, reliability deteriorates with age. Fig.16 plots the outage rates and a weighted average (x axis) for the NEM's coal fleet by age (y axis).

[10] These power stations, built and commissioned by the Queensland Electricity Commission in 1984 and 1996 have held the world record (see Guinness Book of Records) for the most reliable coal-fired power stations since the early-1990s.

Figure 16: NEM coal plant outage rates[11]



Source: EnergyEdge.

Notice in Fig.16 there are two vertical red lines at '120 Quarters' (30 years), and '200 Quarters' (50 years). The former represents the engineering design life of utility-built coal plants, and the latter represents the expected economic life typically exhibited in M&A transactions. The corollary to Fig.16 is that the life of coal plant may always be extended, but this may introduce material risks to system reliability and end user prices in certain circumstances.

7. Policy implications and concluding remarks

With power system planning there is no silver bullet, only policy choices and consequential generation portfolio weightings. Existing markets do not always make investment commitments that trend towards system optimal results, and therefore government policy is important. Our results find the recent investment commitments comprising wind, solar, gas turbines, and storage assets present as lowest cost. If there was a lower cost alternative, forward prices would be pointing southwards towards such an outcome, and as noted above, energy companies would be investing in these alternate supply options. But this is not the case. It seems our wholesale markets have, for now, settled at an equilibrium of ~$90/MWh. This aligns reasonably well with our partial equilibrium power system model results.

Governments can always alter economic gravity in energy markets by underwriting specific plant, old coal or new renewables, using taxpayer funds. It is not for us to question the mandates of elected governments. Our advice to policymakers is to work with capital markets and supply chains, which are under pressure from equity and debt capital markets to decarbonise.

Conversely, capital markets and supply chains need to acknowledge the political economy of stable electricity prices and the reliability of supply. At the time of writing, the NEM is not ready for a procession of incumbent coal plant exits. Stable prices and a reliable supply are essential objectives of government. The political economy of electricity prices means the energy transition cannot come at any cost. If renewable entry costs rise (Appendix IV) we should anticipate slowing activity. But as incumbent plant ages (Fig.15-16), policymakers should anticipate an increasingly nervous set of electricity utility executives, deteriorating market outcomes and risks to prices and reliability. And

[11] Our thanks to Josh Stabler from EnergyEdge for assisting us with the underlying data.

delays in electricity decarbonisation requires faster cuts to other sectors, which have their own challenges and costs. Energy policy entails quite a balancing act.

APPENDICES I to V – See CAEEPR Working papers

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