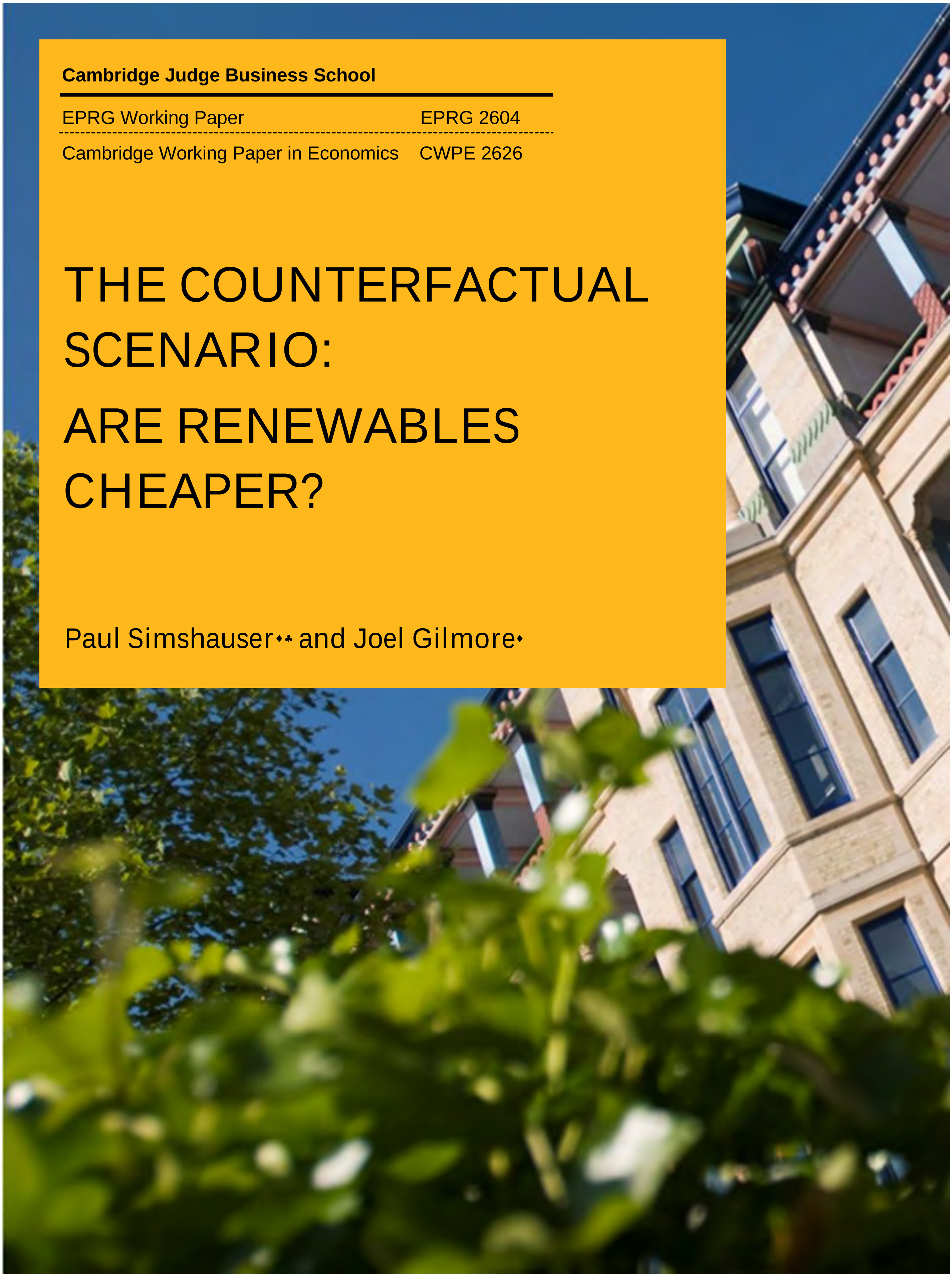

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THE COUNTERFACTUAL SCENARIO: ARE RENEWABLES CHEAPER?

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

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

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The Counterfactual Scenario: are renewables cheaper?

Paul Simshauser[♦♣] and Joel Gilmore[♦]
November 2025

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Electricity prices across Europe, North America and Asia-Pacific surged following the outbreak of the Russia-Ukraine war, driven by severe spikes in LNG and coal prices. In Australia, average household electricity tariffs in the National Electricity Market were ~23c/kWh in 2021. By 2025 tariffs had increased by 33% to ~30c/kWh, and provides an interesting case study of predictable policy aftershocks. 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 in Australia and examine a counterfactual policy scenario – a world where market entrants over the past two decades were constrained to coal- and gas-fired generation, rather than renewables. We compare these results to the NEM's transitioning plant stock, with 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. Our counterfactual policy scenario would result in wholesale market costs and prices ~30-50% higher. 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.

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1. Introduction

Over the past 5 years, global electricity markets have been subjected to non-trivial periodic shocks which have impacted actual (and perceived) energy costs for consumers. Rapid decarbonisation targets combined with high electrification rates has coincided with major disruptions in global fuel and equipment markets. The combination of supply-chain constraints arising from the Covid-19 pandemic, immediately followed by the Russia–Ukraine war, produced a European gas crisis. Sharply rising LNG prices flowed into electricity markets immediately. Amplified wholesale gas and electricity price volatility spread internationally – including as far away as Australia. Post-pandemic supply-chain disruption, higher construction costs and sharply rising interest rates compounded and led to higher entry costs for new renewable generation, and dispatchable (firming) capacity.

In the typical basket of goods and services consumed by households, it is hard to find a more regressive item than energy supply. Dominant thought is that wealthier households consume more than vulnerable households. In Britain, the quantitative evidence is that there is no correlation (Bennett et al., 2002) and in the world's first

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household expenditure survey undertaken in Germany during the 1850s, the same substantive result was revealed (see Stigler, 1954). In Australia, the coefficient is just +0.08 and an R^2 of 0.01 (Simshauser, 2021). In aggregate, household expenditure on energy is regressive.

With electricity bills rising in a so-called *cost of living crisis*, we should anticipate a level of energy policy instability in search of better outcomes (Pollitt *et al.*, 2024; Sæther and Neumann, 2024). We should also anticipate some element or faction of politicians to argue a reversion to fossil fuels, and that energy costs will be politicised (Brännlund and Peterson, 2024). Policy framing can be a key driver of public support (Stokes and Warshaw, 2017) considering jobs, pollution and – critically – residential electricity bills.

Australia provides an informative case study of this pattern. Over the past 15 years in Australia's National Electricity Market (NEM), electricity tariffs have been surprisingly volatile, and energy and climate policy 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 during the same period, while higher rainfalls lowered solar output. Then, electricity equipment supply-chains began to seize up as European investment responded to the curtailment of Russian gas, and in the US, the Inflation Reduction Act compounded order book stress with Original Equipment Manufacturers. In Australia, this coincided with a 30+%[2] increase in construction costs, and when combined with sharply rising interest rates, debt servicing costs for new plant increased threefold. Within three years, the entry cost of onshore wind projects had nearly doubled, and the average residential tariff had risen in nominal terms 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).

Just prior to these revealed cost shocks in Australia, PPA prices for wind and solar PV had been plunging. Indeed, by 2019 the entry cost of wind and solar PV had fallen below the marginal cost of mid-merit coal and gas plant (Simshauser & Gilmore, 2022). 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 applied policy narrative, *renewables would be cheaper*. Given the falling PPA prices in 2019, this policy narrative was not without merit. However, by 2025 the lived experience of Australian households and businesses had been different. Electricity bills had been rising, not falling.

The political economy of 33% electricity tariff increases over a relatively short period is highly problematic and would always induce a substantive policy response. In Australia, *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 its' means-tested tax and transfer system (Simshauser, 2023).

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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

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? This is a long run question and we can unpack this line of policy inquiry vis-à-vis the market's current trajectory by using the best available information, work through its complications, and examine a *counterfactual policy scenario*. Our counterfactual scenario considers what would have happened if policy had never pursued renewables. That is, would a coal and gas fleet produce lower retail tariffs setting aside the adverse environmental considerations? The relevant issue here for Australia's NEM is that, as noted above, the (unsubsidised) entry costs of renewables visibly dropped below the marginal cost of mid-merit coal and gas-fired generation from ~2019 (see Simshauser & Gilmore, 2022). In this article, we aim to test whether this continues for new entrant coal, new entrant gas and new entrant renewables at a whole of power (and gas) system perspective.[3]

For clarity, we focus strictly on the wholesale market[4] and our counterfactual policy scenario examines what could be delivered now. In the Australian context, 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. all of these technologies are observed in the NEM). We start from *'the good old days'* of $40/MWh (US$26) 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 policy scenarios comprising coal and gas.

Headline results are as follows. On a unit cost basis, coal and gas-fired generation were once unambiguously the lowest cost technologies (i.e. in the mid-2000s, setting aside the value of CO_2 emissions). By 2025, the structural cost of fuel had increased at multiples above general rates of inflation. Our 2025 counterfactual policy scenarios, which deploy only coal and gas-fired generation to meet aggregate final demand, prove to be *surprisingly expensive* even without international fuel price shocks.

When we model the Australian NEM's 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 policy 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.

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[3] One Reviewer queried whether this would have occurred in the absence of policy support. In our view, policy support was necessary to capture learning effects of the roll-out of imported technologies (i.e. wind and solar PV) through until ~2019 (see Simshauser and Gilmore, 2022). It was at this point (late 2018 / early 2019) that Australia's sole renewable energy policy (a 20% Target) was thought to have been met. Consequently, from early 2019 ongoing investment commitments in renewable projects represented the lowest cost entrants *excluding subsidies* (noting green certificates are trading at just $4/MWh).

[4] 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. Some dedicated synchronous condensers (with flywheels) would also be required and at ~6 per NEM region would add c.$1-2/MWh to transmission network costs.

2. Review of literature: a brief overview of 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[5], or the market in the early post-NEM reform era. Coal-fired generation was unambiguously lowest cost and over time, many of these state-based power systems would become amongst the lowest cost in the world. However, as with many countries, overcapacity emerged during the 1980s and early 1990s (Schmalensee, 2021) – particularly in the NEM's New South Wales and Victorian regions (Booth, 2000).

Necessary reforms to the electricity industry and associated policy initiatives during the 1990s would ultimately secure bipartisan support (Havyatt, 2022). Remarkably in hindsight, a united approach across the Commonwealth and all State governments was required, and achieved, to create the NEM (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.

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 Australian 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).

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). Public administration and overarching energy policy was therefore the domain of state Governments. Over time, each state built up considerable skill and expertise in its public administration of the sector.

Climate change policies on the other hand were naturally the domain of the Commonwealth government. 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).

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

Evidently, by the late-1990s the science of climate change began to creep into energy policymaking (Crowley, 2017). 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 in Australia – 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 occurred in 2004.

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 an unambiguous and direct consequence (Crowley, 2017, 2021). Even the RET, a largely bipartisan policy introduced by the conservative 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).

2.3 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 at the sub-national level 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) at the national level in Australia, identify the obvious problems with wind and solar – its intermittency (Rangarajan *et al.*, 2025), inter-seasonal volatility (Chyong *et al.*, 2024) and an 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 be relegated to affordability.

Blue team conservatives at the national level 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. 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[6] – 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 policy scenario*.

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 power generation resources, viz. coal, gas, wind, solar, pumped hydro (existing and future site resources), the world's highest take-up rate of rooftop solar, and the highest per capita take-up rate of utility-scale batteries in the world (a consequence of the solar resources). We reconstruct historic 30-minute demand-side data using 2024 data 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, and unwind them in *counterfactual policy scenarios*. In all electricity market model simulations, we apply an own-price elasticity estimate of -0.08 which is broadly consistent with Burke and Abayasekara (2018a), Sergici *et al.*, (2020a) and Simshauser (2022b) while for our natural gas market model, 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 sequentially linked models:

1. 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

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

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). As with Hirth (2013), half-hour resolution modelling over a single reporting year forms the focus of results. Model logic appears in Appendix I. This model analyses our renewable and our counterfactual policy scenarios.

2. 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. Results from this model are used as direct cost inputs in our NEMESYS Model. The PCF Model logic is set out in detail in prior editions of this journal (see Simshauser & Gilmore, 2022) and so we propose not to reproduce it here. For convenience, Appendix II provides a link to the model logic.

3. Our *Gas Partial Equilibrium Model* (GPE Model) is a time-sequential, dynamic structural LP 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. Results from this model are used as inputs to the PCF Model, and our NEMESYS Model. The GPE Model logic is set out in detail in Simshauser & Gilmore (2025) and once again, we propose not to reproduce it here. Once again, for convenience Appendix II provides a link to the model logic.

Our approach to modelling is to utilise 2024 demand data (and associated elasticity coefficients) and 2025 generator costs under conditions of perfect entry and exit and seek to define generalised estimates of long run 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. Note we include sizable transmission costs for renewable plant to cover network augmentations extending from the transmission backbone to wind and solar sites (shaded grey line).

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 II) 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.1), aggregate demand (Fig.2) and the aggregate supply function (Fig.3). All gas transmission pipelines, lengths, connections, capacity (TJ/d) and tariffs ($/GJ) appear in Appendix II along with model logic.

Figure 1: GPE Model demand centres, gas fields and pipelines

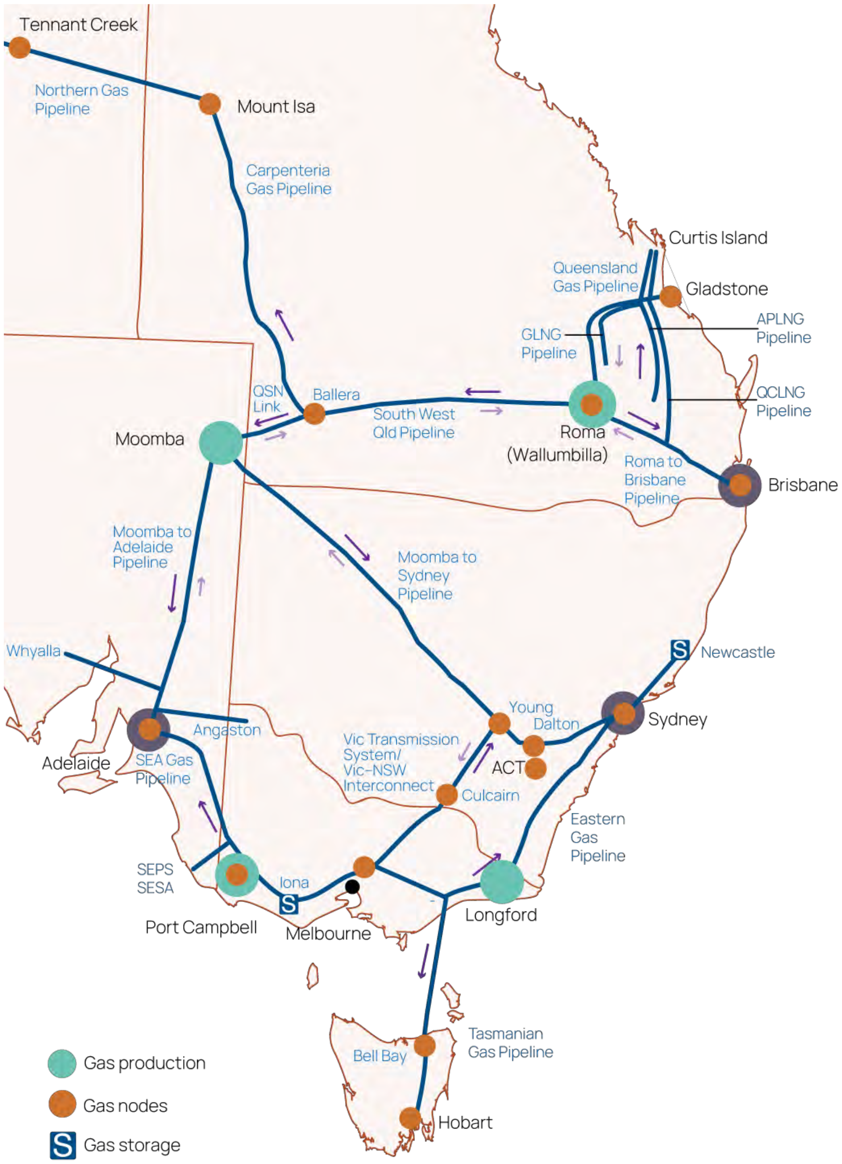
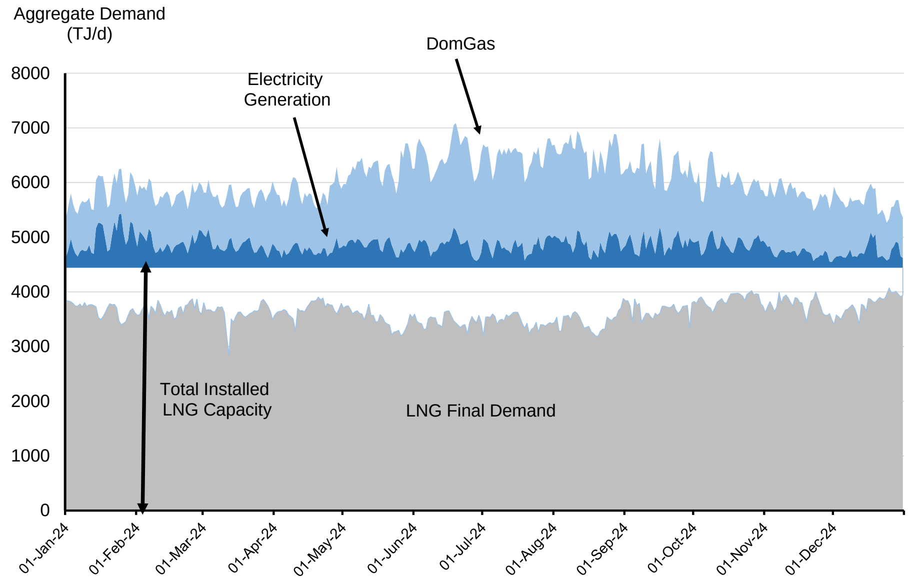
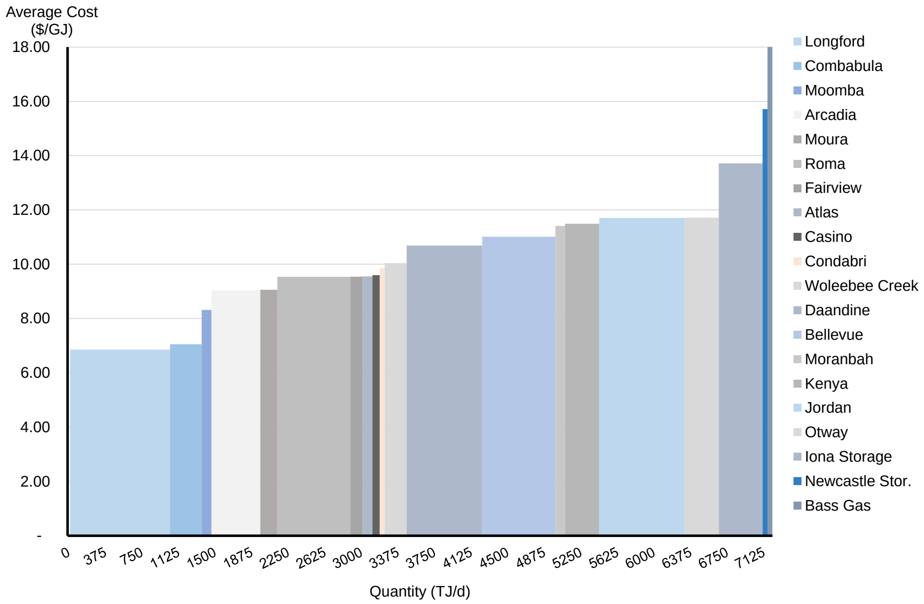


Figure 2: Easten Australian aggregate gas demand (daily resolution)



Source: GMAT. Maximum aggregate gas demand occurs in June/July and exceeds 7100TJ/d, which includes total LNG capacity of ~4500TJ (whereas 'final' LNG demand was ~3700TJ/d – that is, 800TJ/d of possible LNG demand was idle capacity, represented by the white shaded area).

Figure 3: Easten Australian aggregate daily gas supply curve



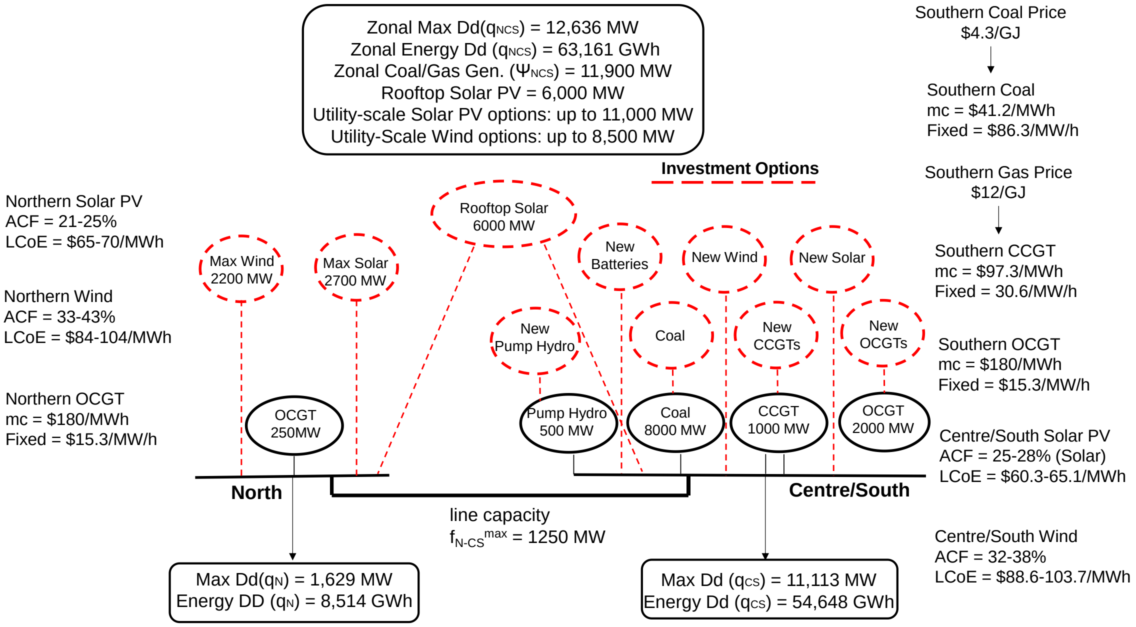
Source: Simshauser & Gilmore (2025)

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.4 (and recall model logic appears in Appendix I). The Model simulates a power system with two major nodes, which in turn provides a simplified representation of the NEM's Queensland region, viz. a Centre/South node with the majority of grid demand plus coal and pumped hydro storage assets, and a North node with very high quality renewable resource but constrained by intra-regional line transfer limits $\left(F_{N-CS^{Max}}\right)$. The solid circles indicate existing aggregate supply, while new entrant options are represented by the dashed circles. Characteristics of the North and Centre/South technology costs are shown on the left and right, respectively.

The top box in Fig.4 depicts aggregate final energy demand (63,161GWh) and maximum demand (12,636MW), which includes self-consumed PV production. These data are used to determine the least-cost expansion plan (utilising the options in the dotted circles) sufficient to meet aggregate final demand and subject to the constraints of each scenario, as discussed throughout Sections 4-5.

Figure 4: 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.

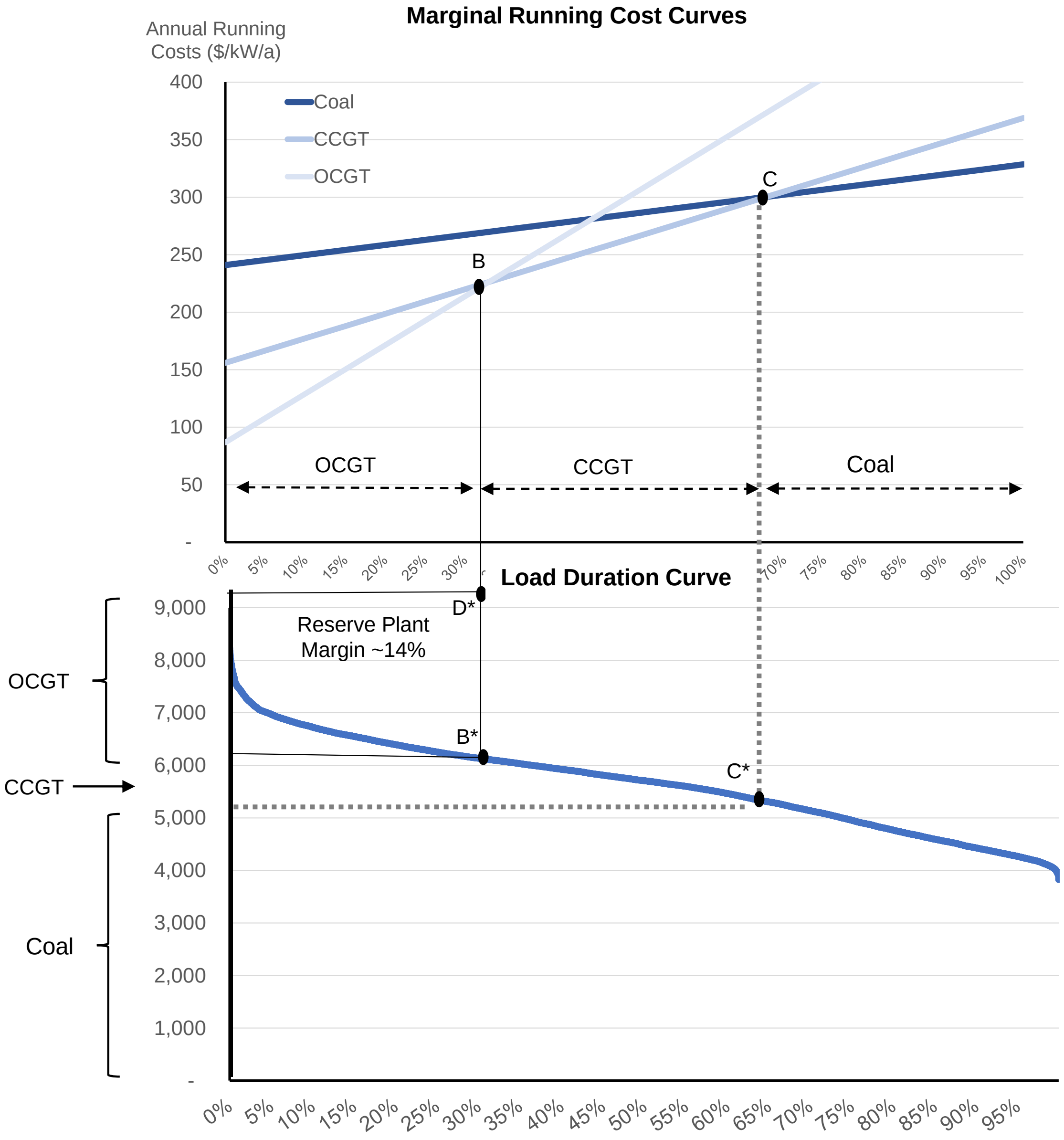
4.1 *Good old days: the 2005 scenario and $40 (US$26/MWh) prices*

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 following extensive restructuring, deregulation and liberalisation (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.5 illustrates this via Berrie's (1967) classic partial equilibrium framework.

The top chart in Fig.5 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.

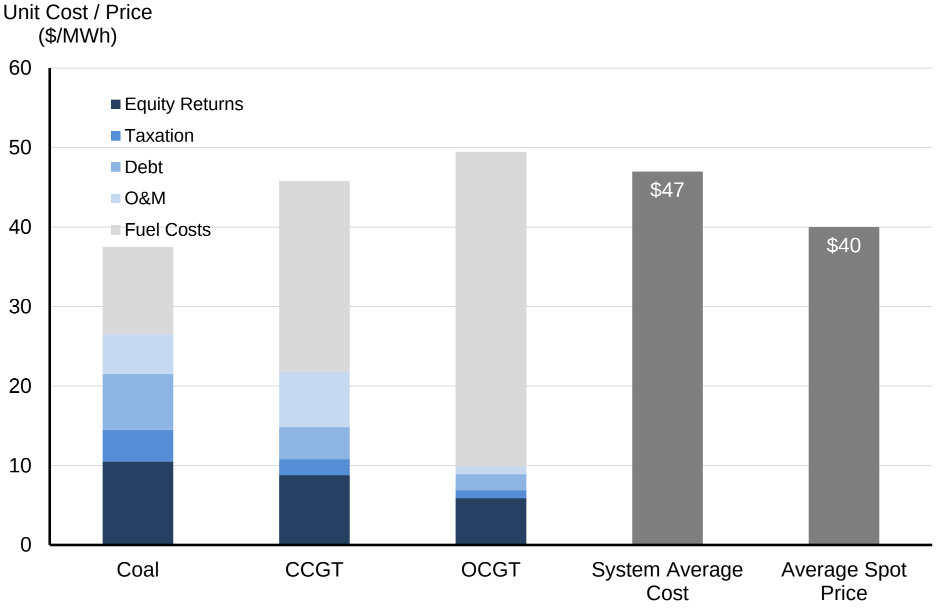
Figure 5: Static Partial Equilibrium – Queensland 2005



Average Total Cost of the three generation technologies, and for the overall Queensland power system under dynamic modelled conditions is illustrated in Fig.6. 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.5.

The final two bars in Fig.6 show system average costs and prices for the 2005 year arising from our NEMESYS Model. System cost in equilibrium is ~$47/MWh (US$31/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 observed 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 (in 2005 dollars).

Figure 6: 2005 Scenario - Queensland plant, system costs and baseload price



4.2 The 2025 *‘counterfactual policy scenario’*

In 2025, the benchmark plant portfolio has transitioned. In Queensland – which has the world’s highest take-up rate of (uncontrolled) 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*.

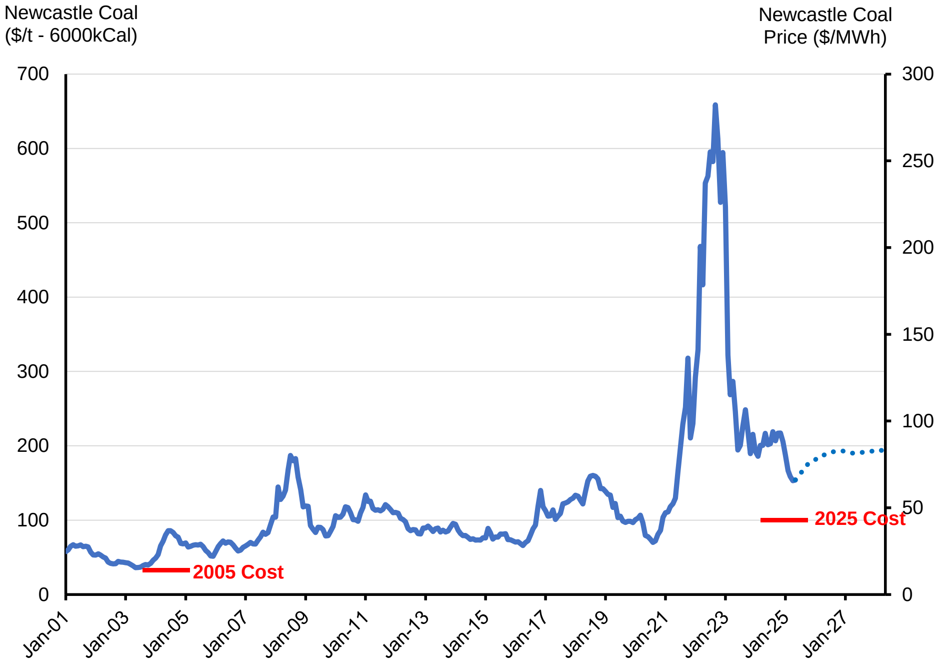
Australia's transition *has itself* transitioned. From 2000-2018, wind and solar entry in the NEM was *policy-driven* through Australia's 20% RET and its associated renewable subsidies (i.e. renewable certificates). Throughout this 19-year period, 125 renewable projects totalling 11,400MW reached financial 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.

As noted in Section 1, from 2019 renewable PPA prices fell below the marginal running costs of existing mid-merit thermal plant. Consequently 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 policy 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 important to examine the evolution of market prices for coal and natural gas, in Fig.7-8, as the critical inputs to any counterfactual.

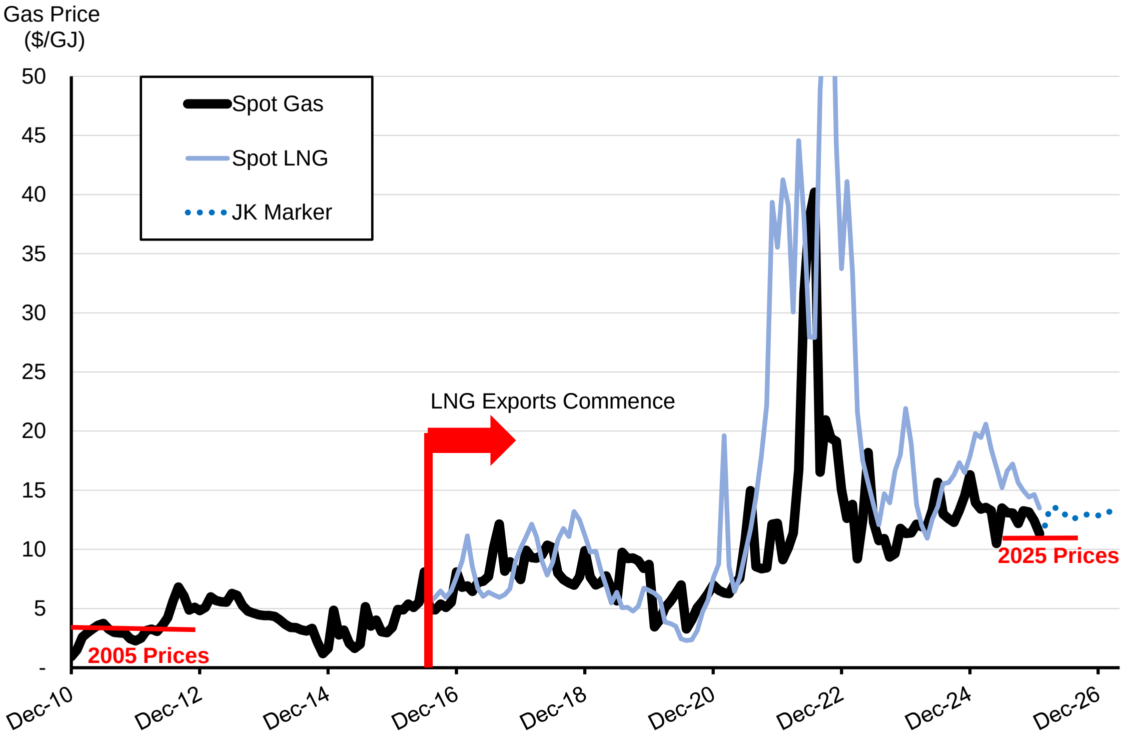
In Fig.7, it can be seen that the price of export coal (blue line series) is now ~8x the value of legacy long-dated coal supply contracts that existed in the mid-2000s (see red line marked '2005 cost'). Export coal is of a high quality and domestic supply is typically lower grade, and at times may be ~25% lower cost. In our analysis of the counterfactual scenario, we will use a very heavily discounted coal cost, set to just ~58% of export forward prices (see red line marked '2025 cost).

Figure 7: Coal prices (2001 – 2028, 6000kcal Futures)



Similar conditions exist in the market for natural gas, as Fig.8 reveals. Compared to 2005 prices, natural gas has increased by a factor of 4, largely driven by international dynamics and structural shortages associated with the development of the Eastern Australian LNG industry (Simshauser & Gilmore, 2025). Note that domestic spot gas prices have moderated from the 2022 Russia-Ukraine event, and align well with our structural LP model results of the East Australian gas market (GPE Model). In short, prevailing spot gas prices reflect industry fundamentals, and the marginal domestic cost of gas production given prevailing gas demand.

Figure 8: Domestic and export gas prices (2010-2025, Japan-Korea Marker)



In Fig.9, 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 relevant consumer price index, and finally, contrast these historical data points with contemporary ‘2025’ cost estimates from our PCF Model (third bar series).

Figure 9: Unit cost comparison 2005 vs 2025

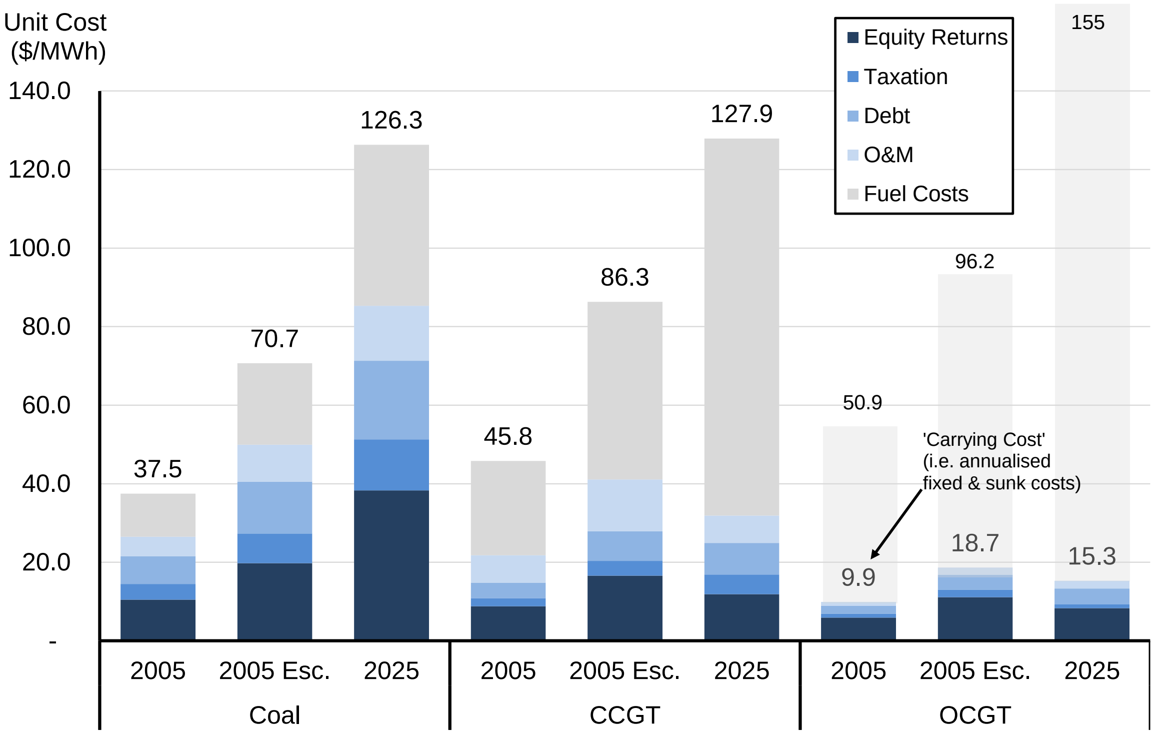


Fig.9 reveals a striking set of results. Our '2025' results bear little resemblance to '2005 Esc' scenario results, that is, 2005 results escalated at the cumulative consumer price index over the period 2005-2025. So why have 2025 thermal plant costs increased so materially, even when conservative assumptions are used to avoid over-emphasising the risks of transient shocks?

Recall from Fig.8 that we use a unit cost of coal of $100/t (or ~$4.3/GJ) which is 58%[7] of the prevailing forward export price series (see Fig.8, red line marked '2025 cost'), which remains broadly flat over the visible forwards to 2028. 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, but still 40-70% lower than in 2022. As noted previously, this reflects industry fundamentals and forecasts of the marginal cost of natural gas (per our GPE Model). To be clear, if CCGTs are deployed as the new baseload fleet, re-running our GPE Model with the higher gas market demand suggest clearing prices would rise from $12/GJ to $12.7/GJ.

Looking at capital equipment, the cost of gas-fired generation plant has risen broadly in line with inflation whereas 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 Australia in the current environment is unknown. We scraped data from the

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[7] We assume an otherwise stranded resource.

US s144A bond market for utilities with and without (sunk) coal-fired generation portfolios. *Prima facie*, these data appeared to imply a ~50bps spread for portfolios comprising aging coal assets (vs no 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:

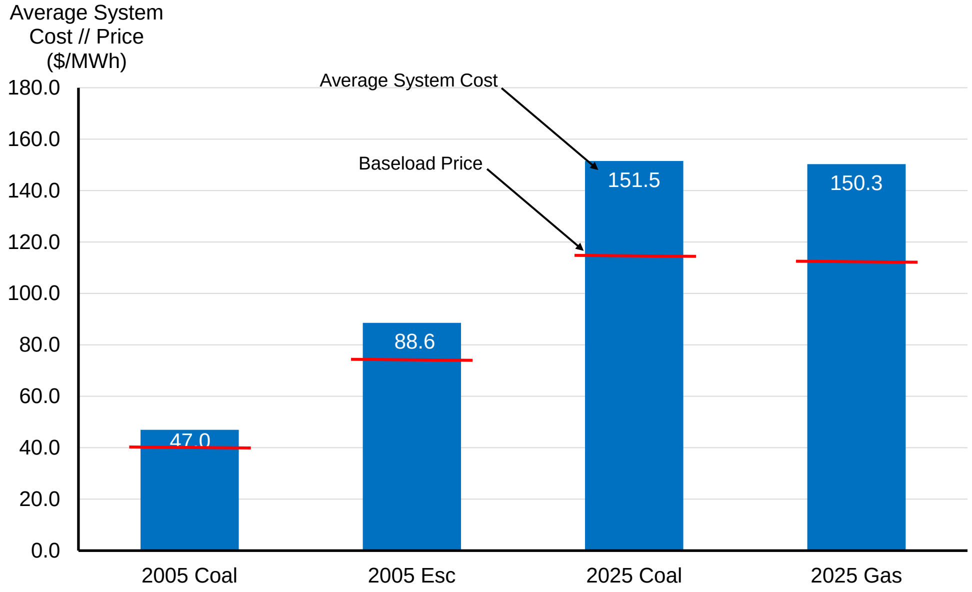
- Coal credit spreads: +150-200 basis points
- Gas credit spreads: +100-150 basis points

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 in out PCF Model. While this likely *materially 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 OCGTs will play in a transitioned plant stock (Simshauser and Gilmore, 2025; Simshauser, 2026).

When the results in Fig.9 are migrated to our NEMESYS (power) and GPE (gas) system models, we find unit costs and clearing prices in the counterfactual policy scenario at substantially higher levels than our escalated 2005 benchmark, as illustrated in Fig.10.

Figure 10: ***The counterfactual policy scenario*** **- system costs / prices**



Working from left to right, the first bar in Fig.10 replicates our 2005 simulation. When these data are escalated into constant 2025 dollars, system average cost is $88.6/MWh (blue bar series) and baseload prices are ~$76/MWh (red line series). The remaining two bars represent our 'counterfactual policy scenarios' simulated in NEMESYS where only coal ('2025 Coal' scenario) or only gas ('2025 Gas' scenario) is deployed to meet aggregate final demand. Both counterfactual scenarios assume 0% renewables – which extends to excluding rooftop solar PV.

The first point to note from these *counterfactual policy scenarios* is that they all exhibit materially higher system costs and prices. This is being driven by our entry cost estimates in Fig.9. By implication, if our Fig.9 estimates were too high, then Fig.10 results would move down (and vice versa).

In aggregate, our counterfactual scenarios present sobering results. Outcomes are overwhelmed by elevated coal ($4.3/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 (without policy subsidies) 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.11. 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.4. 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.11.

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)[8].

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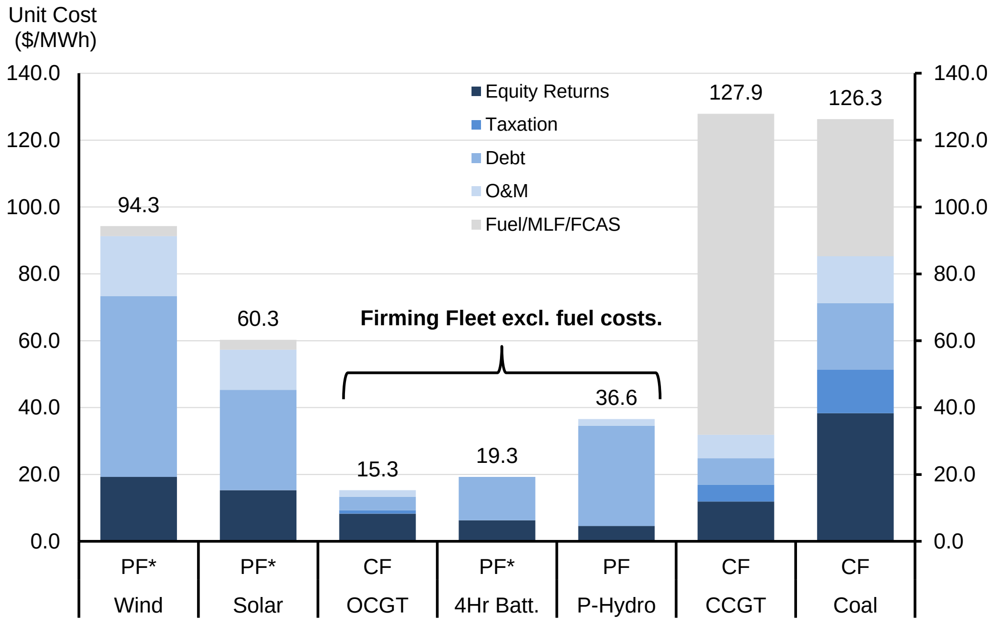
[8] Pumping costs for hydro, and charging costs for batteries, are an outcome of dynamic system modelling. To generalise, pumping/charging costs fall as solar market shares rise, whereas their generation dispatch prices tend to rise as coal plant exits.

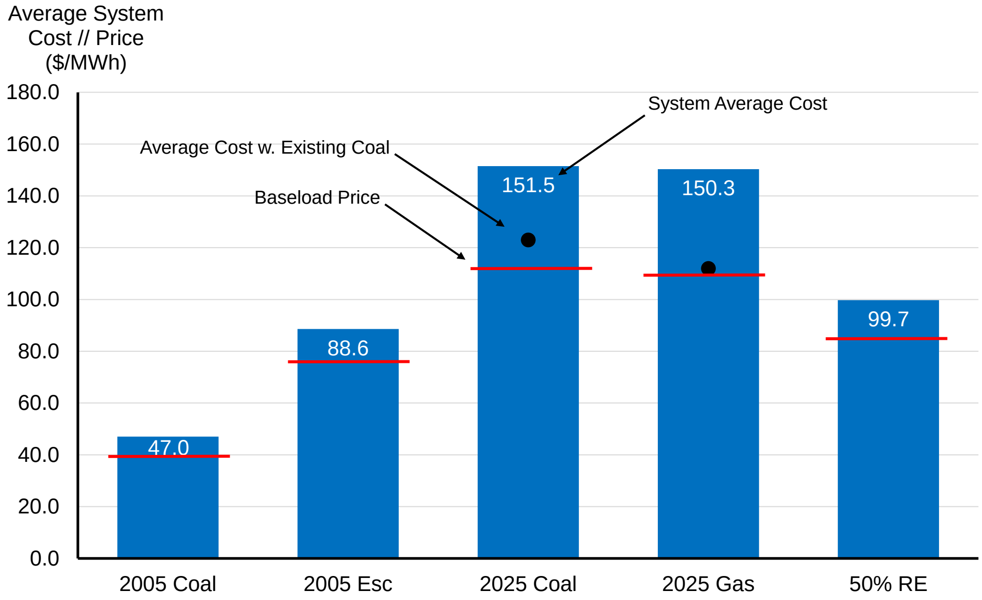
Figure 11: Generalised average total cost of generation plant in Qld



PF* 75% PPA Cover

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.12. Working from left to right, bars 1-4 have been reproduced from Fig.10 for ease of comparison, with the final bar representing the 50% renewable scenario.

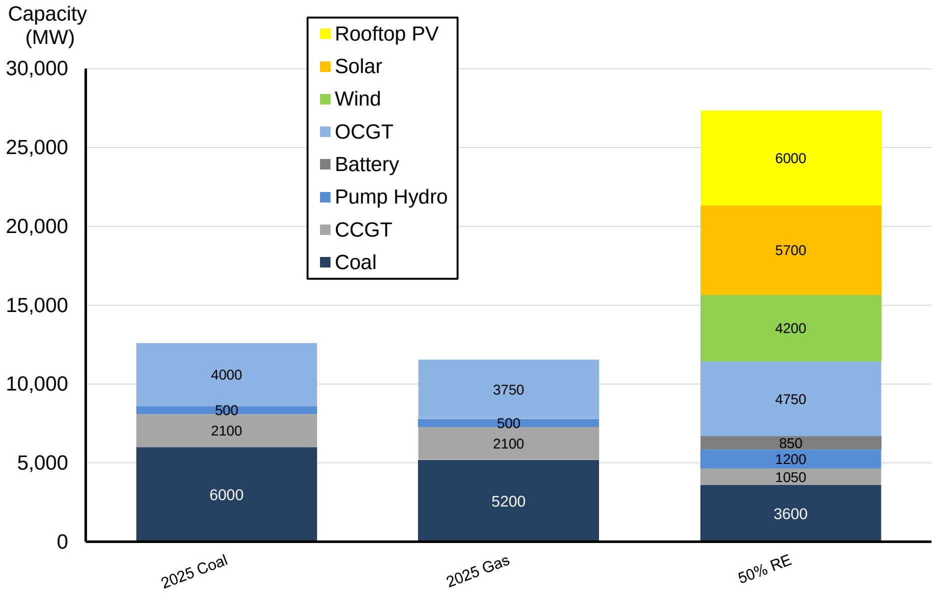
Figure 12: Counterfactual policy scenario v renewable policy scenario



With Fig.12, 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. 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.12 results is that the ‘50% RE’ scenario exhibits lower costs and prices than our *counterfactual policy scenarios*. Furthermore, the ‘50 RE’ policy 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.12 are illustrated in Fig.13.

Figure 13: Counterfactual and RE plant stock



In any counterfactual analysis, there are an array of factors that could lead to costs, prices and capacity outcomes that differ from our model results presented above. For example, as one reviewer pointed out, a substantially decarbonised grid may be attractive for certain new loads (e.g. data centres) which has not been accounted for here. Furthermore, a coal and gas only system would exhibit different industrial organisation than a system with a sharply rising level of independent renewable entrants. Finally, we have not included the historic or current costs of renewable subsidies (noting the prevailing price of renewable certificates is now ~$4/MWh)[9].

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[9] We have also focused on the wholesale market, and have not analysed changes in network costs, and other components of a retail electricity bill such as green schemes, energy efficiency schemes, carbon costs, feed-in tariffs, etc. However historically, these costs are small compared to total (underlying) delivered electricity costs.

6. Incumbent coal plant: age and reliability effects

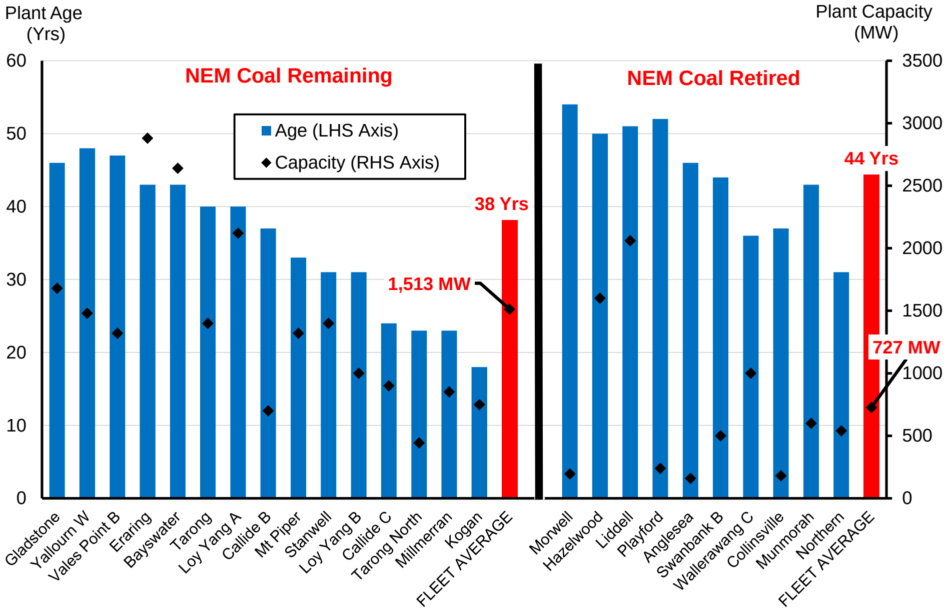
In our modelling suite, many incumbent coal plants are low cost given the absence of a direct price on CO_2 externalities in Australia. As they exit, the unit cost and price of electricity will gradually rise. There are exceptions to the rule, however. Certain black coal power stations in the NEM are 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 environmental (i.e. biodiversity) licencing and community acceptance constraints.

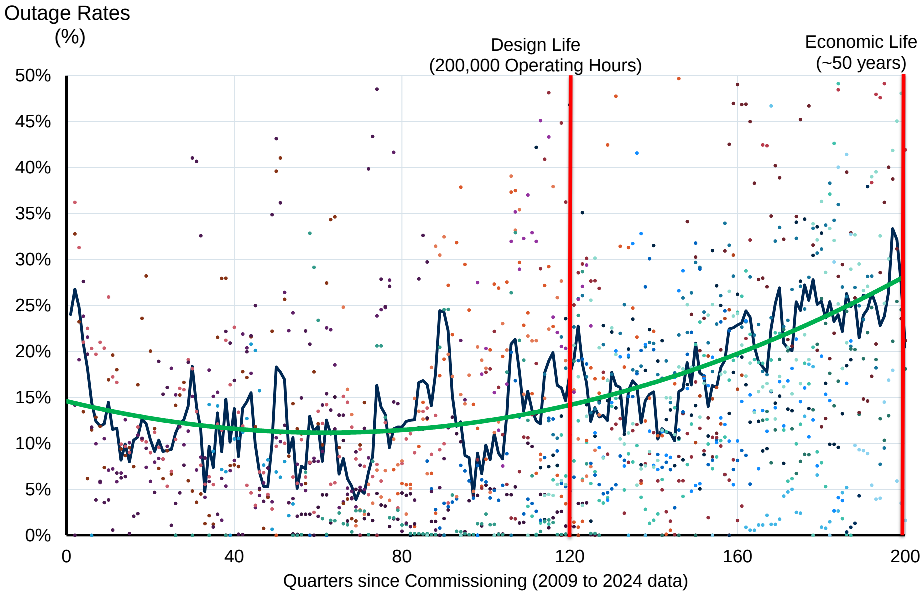
Yet incumbent coal plants face speed limits. Fig.14 presents the NEM's coal fleet in two distinct portfolios. The left panel comprises the NEM's existing 20GW coal fleet, spread across 15 power stations. The right panel comprises the 10 coal plants which have already exited. Note the average age of the 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 across the NEM regions.

Figure 14: 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 is ~94% availability.[10] But as a fleet, reliability deteriorates with age. Fig.15 plots the outage rate of all individual coal plants (y-axis) by age (x-axis) along with the weighted average (blue line series) and trend (green line series).

Figure 15: NEM coal plant outage rates[11]



Source: EnergyEdge.

Notice in Fig.15 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.15 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 portfolio weightings. 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 lower, towards such an outcome, with energy companies investing in these alternate supply options. This is not the case. It seems our wholesale markets have, for now, settled at an equilibrium of ~$90/MWh for Australia at the time of writing. This aligns reasonably well with our partial equilibrium power system model results. Results for international markets will depend on the local

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[10] This sustained benchmark was set by three power stations in Queensland, viz. Tarong, Callide and Stanwell (built and commissioned by the Queensland Electricity Commission in 1984, 1988 and 1996). Each held the world record (see Guinness Book of Records) for the most reliable coal-fired power station since the early-1990s.

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

characteristics, but the findings of this manuscript are consistent with trends across international markets, including India and China (He *et al.*, 2020; Chakravarty and Somanathan, 2021; Lazard, 2025).

Governments can always alter the 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. These are essential objectives of government. Specifically, the political economy of electricity prices means the energy transition cannot come at any cost. If renewable entry costs rise, we should anticipate slowing activity. Nevertheless, as incumbent plant ages (Fig.14-15), policymakers should anticipate an increasingly nervous set of electricity utility executives, deteriorating market outcomes and risks to prices and reliability. Furthermore, delays in electricity decarbonisation requires faster cuts to other sectors, which have their own challenges and costs. Energy policy entails quite a balancing act.

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Appendix I – NEMESYS Model Logic

Let *H* be the ordered set of all half-hourly trading intervals.

$$i \in \{1 \ldots |H|\} \wedge h^i \in H, \tag{1}$$

Let *N* be the ordered set of nodes within the regional power system and let |*N*| be the total number of nodes in the set. Let η_n be node n where:

$$n \in (1..|\mathcal{N}|) \wedge \eta_n \in \mathcal{N}, \tag{2}$$

Aggregate final (grid-supplied) demand at each node comprises residential, commercial, and industrial consumer segments. Let *E* be the set of all electricity consumer loads in the model.

$$w \in \{1 \ldots |E|\} \wedge e_w \in E, \tag{3}$$

Let $V_w(q)$ be the valuation that consumer segment w is willing to pay for quantity q MWh of electricity. Let $q_{w,n}^i$ be the metered quantity consumed by customer segment w in each trading interval i at node n expressed in Megawatt hours (MWh). In all scenarios and iterations, aggregate demand is modelled as a strictly decreasing and linear function with own-price elasticity of -0.08 (see (Burke and Abayasekara, 2018b; Australian Energy Market Operator (AEMO), 2019; Sergici *et al.*, 2020b) applied by reference to average wholesale prices p during solar periods, evening peak, and overnight periods against the equivalent ‘base case’ reference prices.

Generation investment and spot market trading are assumed to be profit maximising in a perfectly competitive market with all firms as price takers, thus yielding welfare maximising outcomes within the technical constraints outlined below. Let Ψ_n be the ordered set of generators at node n.

$$\mathscr{g} \in \{1..|\Psi_n|\} \wedge \psi_{n\mathscr{g}} \in \Psi_n, \tag{4}$$

Conventional plant are subject to a regime of both scheduled and forced outages. Planned outages are simulated at the rate of 35 days every 4th year, while forced outages are the subject of random simulations equivalent to ~3-6% per annum. Let $\mathrm{F}(n, \mathscr{g}, i)$ be the availability of each plant $\psi_{n\mathscr{g}}$ in each period i. Annual generation fleet availability is therefore:

$$\sum_{g=0}^{|\Psi_n|} F\,(n, \mathscr{g}, i)\ \forall\ \eta_n, \tag{5}$$

Conventional plant face binding capacity limits and minimum load constraints. Let $\hat{g}_{\psi_{n\mathscr{g}}}$ be the maximum productive capacity of generator $\psi_{n\mathscr{g}}$ at node n and let $\breve{g}_{\psi_{n\mathscr{g}}}$ be the minimum stable load of generator ψ_n. Plant marginal running costs are given by $mc_{n\mathscr{g}}$. Let $g_{\psi^i_{n\mathscr{g}}}$ be generation dispatched (and metered) at node n by generator ψ_n in each trading interval i expressed in MWh. Let d^i_n be the cleared quantity of electricity delivered in trading interval i at node n expressed in MWh.

In our model, the Pumped Hydro plant form part of the incumbent plant stock and are a potential entrant. The pumped hydro fleet operates with imperfect foresight, using ‘demand triggers’ (MW) as a proxy for *water opportunity cost* as is frequently employed by long-duration storage assets. Pumped hydro plan operate as a single unit in each node. Define ρ^i_n as the *residual demand* in node n, being demand plus net interconnector flows (imports) into node n (defined below) minus available variable renewable generation, defined as follows:

$$\rho^i_n = \sum_w q^i_{w,n} - \sum_{\overline{\mathscr{g}}} \mathrm{F}(n, \overline{\mathscr{g}}, i) - \sum_{\Omega_A} f^i_{An}, \tag{6}$$

where the sum over generating units is over zero marginal running cost renewable generators $\overline{\mathscr{g}}$. Pumped hydro production is modelled to increase linearly from zero to nameplate capacity over a set range. Let $\xi_{+,0}$,n and $\xi_{+,full,n}$ (subject to additional constraints set out below) be the production range. This structure avoids sharp discontinuities in dispatch for small changes in demand. Similarly, let $\xi_{-,0}$ and $\xi_{-,full}$ be the demand range for charging (pumping) behaviour. These levels are set empirically to match typical operational behaviours, specifically at the 40th to 50th percentiles (charging) and 65th to 70th percentile of residual demand (generating).

Let SOC^i_n be the available stored energy for pumped hydro in region n, constrained by the nameplate storage capacity via $0 \leq SOC^i_n \leq SOC^{max}_n$, and satisfying the following energy balance timeseries:

$$SOC^{i+1}_n = SOC^i_n - g_{\psi^i_{n,phes}} \tau \times \{\gamma_n\ if\ g_{\psi^i_{n,phes}} < 0\} \tag{7}$$

where $\psi_{n,phes} \in \Psi_n$, τ is the simulation timestep, and γ_n is the average round-trip efficiency of the PHES fleet in that node. Initial conditions are $SOC_n^0 = SOC_n^{max}$. Finally, PHES charging load is constrained to be no more than the available renewable energy and coal capacity in each dispatch interval (i.e., the PHES will not charge off gas units). The PHES pumping load in each period is therefore given by:

$$g_{\psi_{n,phes}^i\,(pumping)} = (-1) \times minimum\ of \begin{cases} \hat{g}_{\psi_{n.phes}} \times \min\left(1, \max\left(0, \frac{\rho_n^i - \xi_{-,full,n}}{\xi_{-,0,n} - \xi_{-,full,n}}\right)\right) \\ (SOC_n^{max} - SOC_n^i)/\tau/\gamma_h \\ \left(\sum_{g \in \psi_{n,coal}^i} \hat{g}_{\psi_{ng}}\right) - \rho_n \end{cases} \tag{8}$$

For generation, output is similarly constrained to available SOC_n^i and the residual demand net minimum stable operating levels of coal units.

$$g_{\psi_{n,phes}^i(generating)} = minimum\ of \begin{cases} \hat{g}_{\psi_{n.phes}} \times \min\left(1, \max\left(0, \frac{d_n^i - \xi_{+,0,n}}{\xi_{+,full,n} - \xi_{+,0,n}}\right)\right) \\ (SOC_n^i)/\tau \\ \rho_n - \left(\sum_{g \in \psi_{n,coal}^i} \check{g}_{\psi_{ng}}\right) \end{cases} \tag{9}$$

Batteries arbitrage the highest and lowest demand periods on a day based on perfect foresight within the day. Batteries dispatch in the highest dispatchable demand periods and charge in the lowest periods. We assume batteries constrain their activity to one cycle per day, with commercial constraints described below. Given nodal battery $\hat{g}_{\psi_{n.bess}}$ with nameplate energy storage capacity $S_{\psi_{n.bess}}$, for each simulation day D^d, let $\{\delta_n^{d,j}\}$ be the ordered (descending) set of *dispatchable demand* available to batteries defined as residual demand in node n net of either coal minimum load (if batteries can economically displace coal) or coal nameplate capacity (if batteries should preferentially displace gas),

$$\{\delta^{d,j}\} = \mathrm{SortDescending}\left[\mathrm{\rho_n^i} - \sum_{g \in \psi_{n,coal}^i} \left[\check{g}_{\psi_{ng}} \text{ or } \hat{g}_{\psi_{ng}}\right] - g_{\psi_{n,phes}^i}\right],$$

$$\rho_n^i \in \{1 \ldots |D^d|\} \wedge D^d \subset H. \tag{10}$$

Dropping the superscript d and subscript n for clarity, battery dispatch q^j in each sorted interval is optimised to minimise the number of periods of non-zero dispatch $|\{1\ if\ q^j > 0\ else\ 0\}|$ subject to constraints that dispatch in each period is less than nameplate capacity $q^j \le \hat{g}_{\psi_{n.bess}}$, is less than available demand $q^j \le \delta^j$, and either $\sum_{j\ s.t.\ q^j > 0} q^j = S_{\psi_{n.bess}}$ or $|\{1\ if\ q^j > 0\ else\ 0\}| = |\mathrm{D}|$ (i.e., the battery has either dispatched its total storage capacity across the day or there was insufficient dispatchable demand to do so).

By default, battery dispatch is constrained to never oppose PHES operation. Symmetric calculations are applied to battery charging, charging in the lowest *dispatchable demand* periods but constrained not to charge off gas, i.e., dispatchable demand is below coal headroom s.t. $\delta^j \le \sum_{g \in \psi_{n,coal}^i} \left(\hat{g}_{\psi_{ng}} - \check{g}_{\psi_{ng}}\right)$. Battery dispatch in each day is then remapped to the original indices to obtain the final net dispatch, $g_{\psi_{n,bess}^i}$ (positive for generation, negative for charging).

Let $p_{\psi^i}(q)$ be the uniform clearing price that all dispatched generators receive for generation dispatched or pay during charging, $g_{\psi_n^i}$. Were it not for network constraints, generation and transmission investment options, the problem to be solved is in fact a simple one:

$$\min_{q_n^i}\left(\sum_i mc^i_{\psi_{n\not{g}}}\left(g_{\psi^i_{n\not{g}}}\right)q_n^i\right), \tag{11}$$

where

$$\exists\psi^i_{n\not{g}}\middle|if\ \left(g_{\psi^i_{n\not{g}}}\right)\begin{cases}\neq 0, 0<\check{g}_{\psi_{n\not{g}}}<g_{\psi^i_{n\not{g}}}<\hat{g}_{\psi_{n\not{g}}}\forall\,\psi_n\\ =0,0\end{cases}\wedge\left[\left(\sum q^i_{w,n}-\sum g_{\psi^i_{n\not{g}}}\right)/\sum q^i_{w,n}\right]\ngtr USE, \tag{12}$$

and

$$If\ \left(\sum q^i_{w,n}-\sum g_{\psi^i_{n\not{g}}}>0\middle|USE>0, p_{\psi^i}(q)=\$17{,}500/\mathrm{MWh},\right), \tag{13}$$

Unserved Energy (USE) defines the reliability constraint. In the model, the NEM's reliability standard is used with USE not to exceed 0.002%. Eq.(12) constrains unit commitment of each generator $g_{\psi^i_{n\not{g}}}$ to within their credible operating envelope, and for the market as a whole to operate within the reliability constraint, USE. Eq.(13) specifies that any period involving load shedding, market clearing prices default to the Value of Lost Load of $17,500/MWh, noting this has a tight nexus with the reliability standard.[12]

Let Ŧ be the ordered set of transmission lines t_j linking nodes, and let $|\text{Ŧ}|$ be the number of transmission lines in the zone.

$$t_j\ \in\ (1..|\text{Ŧ}|)\wedge\ t_j\in\ \text{Ŧ}, \tag{14}$$

Let Ω_A and Ω_B be two nodes directly connected to transmission line t_j where

$$\Omega_A\in\ \text{Ɲ},\wedge\,\Omega_B\in\text{Ɲ}\ |\Omega_A\neq\Omega_B, \tag{15}$$

Let f_{AB} be the flow between the two nodes. Let $\hat{f}_j$ be the maximum allowed flow along transmission line t_j and let $\check{f}_j$ be the maximum reverse flow. The clearing vector of quantities demanded q_n^i or supplied at node n in each trading interval i is given by the sum of flows across all transmission lines starting at that node, less flows across transmission lines ending at that node, if applicable. Net positive quantities at a node are considered to be net supply $g_{\psi_n^i}$ $(i.e.\sum g_{\psi^i_{n\not{g}}})$ and negative quantities imply net demand V_n^i:

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[12] From a power system planning perspective, the overall objective function is to minimise $VoLL\ x\ USE+\sum_{i=1}^{n}c(G)\ |\ VoLL\ x\ USE+c(\bar{G})=0$, where $VoLL$ is the Value of Lost Load, USE is Unserved Energy, and where $c(G)$ is the cost generation plant, and $c(\bar{G})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between Reliability and the VoLL. An alternate expression where reliability criteria is based on Loss of Load Expectation is $LoLE=CONE/VoLL$, where CONE is the cost of new entry. For an excellent discussion on the relationship between VoLL and reliability criteria.

$$if\ q_n^i \begin{cases} \geq 0, g_{\psi_n^i} = q_n^i \\ \leq 0, V_n^i = -q_n^i, \end{cases} \tag{16}$$

Integration of plant costs in the model centres around the transposition of three key variables, Marginal Running Costs $mc_{\psi n}$ Fixed O&M Costs $FOM_{\psi n}$ & where applicable (annualised) new entrant generator Capital Costs, $K_{\psi n}$ and (annualised) new Transmission line Capital Costs, K_{tj}. These parameters are the key variables in the half-hourly power system model and are used extensively to meet the objective function.

Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integrals of demand curves less marginal electricity production costs and any (annualised) generation $K_{\psi n}$ or transmission K_{tj} augmentation costs. The objective function is therefore expressed as:

$$\text{Obj} = \left[\sum_{i=1}^{|H|}\sum_{w=1}^{|E|}\sum_{n=1}^{|\mathbb{N}|}\int_{q=0}^{v_n} V_n\left(q_{n,w}^i\right)\partial q\right] - \left[\sum_{i=1}^{|H|}\sum_{n=1}^{|\mathbb{N}|}\sum_{\psi=1}^{|\Psi|}\int_{q=0}^{g_{\psi n}} mc_{\psi n}\left(q_{\psi,n}^n\right)\partial q + FOM_{\psi n} + \sum_{n=1}^{|\mathbb{N}|} K_{\psi n} + \sum_{j=1}^{|\text{Ŧ}|} K_{tj}\right] \ , \tag{17}$$

S.T

$$0 \ \leq \ q_i \leq V_i \wedge \check{f}_j \ \leq \ f_i \ \leq \ \hat{f}_j \wedge \ 0 \leq \check{g}_{\psi i} \leq g_{\psi i} \leq \hat{g}_{\psi i.}$$

Appendix II - Counterfactual Scenario Link to Model Logic