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The Forward Market Dilemma in Energy-Only Electricity Markets

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Abstract

Spot prices in energy-only markets, particularly those with high market price caps, are inherently volatile. As a result, the forward market for hedge contracts is a crucial design feature which guides systemic stability and allows the adequate operation of competitive wholesale and retail markets. Hedge contracts have historically been sold by large base, intermediate and peaking generators to risk-neutral and risk-averse energy retailers. However, as the electricity sector decarbonises and intermittent renewable market share rises, baseload plant exit is predictable, and along with them, so does their hedge contract capacity. Many governments are seeking to accelerate the entry of renewable projects through government-initiated two-way fixed price Contracts-for-Differences (CfDs), typically by way of auction. Because government is the counterparty, CfDs are 'off-market' and unless carefully designed, can produce a structural shortage of primary issuance hedge contract capacity. We model the forward markets in Australia's National Electricity Market and find structural shortages may materialise if off-market fixed price methods dominate because the CfD forms the 'primary hedge' for renewable entrants – and output cannot be prudently hedged twice. Conversely, when on-market Power Purchase Agreements dominate, or government CfDs are structured to be compatible with active forward market participation by renewable entrants, shortages are eliminated.

Keywords: Energy-only markets; forward contract derivative markets; renewables.

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1. Introduction

Under the classic energy-only gross pool wholesale electricity market design, a core feature is a liquid forward market for derivative contracts, traded either through standardised products over different time horizons, or via long-term Power Purchase Agreements (PPAs). On-market forward contracting is critically important. Hedge contracts provide the link between new entry and secure revenues for the financing of plant construction and place natural limits on generator spot market behaviour (i.e. to manage contract positions). More crucially, forward markets form the basis for risk-neutral and risk-averse energy retailers to manage price risk associated with customer loads. To date, there have been thousands of articles examining electricity spot markets. Curiously, comparatively few articles investigate and model contract market fundamentals and dynamics.

When electricity market reforms led to the separation of generation from retail, there was an increasing requirement for coordinated risk allocation – something vertical integration had previously solved internally. The need for coordinated risk allocation across electricity markets is how electricity derivatives evolved to cover generation and retail supply (Hogan, 2016; Wilson, 2002). In the simplest form, contracts were sold by generators to energy retailers to mitigate adverse spot market exposures of both counterparties, providing upward price risk protection to retailers, and downward price risk protection for generators. Some level of vertical re-integration would often supplement forward markets, and in the Australian case, with no material loss of liquidity (see Simshauser, 2021).

Globally, electricity markets are now going through a transition with the requirement to reduce carbon emissions. In Australia, decarbonisation of the electricity system forms a central component of policy (Flottmann, 2024; Hudson, 2019; Nelson, Gilmore, et al., 2022; Nelson, Nolan, et al., 2022; Warren et al., 2016). In consequence, legacy coal plant in Australia's National Electricity Market (NEM) are being replaced by increasing quantities of wind and solar PV. In doing so, traditional forward contract sellers (coal generators) are being progressively removed from forward markets, whilst traditional contract purchasers (energy retailers) remain.

At the same time, across the world's major electricity markets (including Australia), an emerging trend is the increasing amount of wind and solar plant (Variable Renewable Energy or 'VRE') being contracted through government-initiated Contracts-for-Differences (CfDs) – frequently via a two-way fixed price structure. Indeed, in the NEM, national and sub-national governments have initiated 6.5GW of CfDs by way of auction (AEMO, 2024; ClimateChoices, 2023; DEECA, 2023, 2024; DES, 2020).

The use of government-initiated CfDs has been highly successful in facilitating plant entry, and, in aggregate the impact on forward markets appears to have been relatively benign. However, accelerating use of two-way fixed price CfDs intended to meet nominal renewable energy targets could damage forward market depth, liquidity and ultimately hedge capacity if governments – not energy retailers – become the dominant counterparties to these transactions. A two-way fixed price structure is a complete hedge, and generators cannot hedge the output from the same VRE project twice.

Furthermore, when a forward market experiences falling liquidity, the progressive exit of proprietary traders and 'second tier' retail suppliers is predictable. Rising retail margins of incumbent ('tier one') energy retailers then typically follows. Conversely, carefully designed CfDs that encourage active re-trading, or CfD recycling in secondary markets (by government), can mitigate hedge contract shortfalls.

This article aims to assess whether and how baseload coal exit, driven by an increasing market share of VRE underwritten by government-initiated (i.e. 'off-market') two-way fixed price CfDs could lead to shortfalls of 'primary issuance' hedge contract capacity. Such shortfalls may arise either due to perceived risks of double hedging and paying out twice under a fixed price structure, or because the auction design (by providing a floor on returns) unintentionally encourages active spot market exposure rather than hedging by successful auction participants. We set out a framework to determine if any regions of an energy market (i.e. the NEM regions in this instance) are currently experiencing, or are at risk of experiencing, hedge contract capacity shortfalls.

The balance of this article is structured as follows. Section 2 provides an overview of the problem along with a brief background on NEM spot market dynamics and forward markets. Section 3 outlines methods and data used. Section 4 presents results for a generalised scenario which outlines how contracting levels are formulated. Section 5 presents the results for each mainland NEM region including the source of any shortfall. Policy recommendations and conclusions follow.

2. Primer of Australia's NEM and an overview of the problem

2.1 NEM spot market overview and coal plant exit

Australia's NEM is an energy-only gross pool with a very high market price cap of $17,500/MWh. The market operates across the six eastern states and territories, viz. Queensland, New South Wales (NSW), the Australian Capital Territory, Victoria, South Australia and Tasmania. The Australian Capital Territory is included within the NSW region to make up the five market regions or zones (Mayer & Trück, 2018). Zones are imperfectly interconnected, meaning some level of basis risk exists when undertaking long-run inter-regional hedging[1].

The mainland NEM zone with the largest market share of intermittent renewable energy is South Australia (SA), at 72% market share. SA regularly experiences over 100% renewables and must export excess electricity to neighbouring Victoria, curtail VRE production, or both. In comparison, Victorian electricity generation is made up of 40% VRE whilst still highly dependent on aging brown coal generators (lignite), gas-fired generation and inter-regional transfers to meet peak demand.

Of relevance to our analysis, the rapid closure of coal power stations in SA and Victoria caused problems for jurisdictional government electricity planning. In 2016, SA's last coal generator (Northern Power Station) exited the market, closely followed by the exit of a large brown coal generator (Hazelwood) in the adjacent Victorian region in 2017 (Nelson, 2018). Combined, this resulted in elevated spot electricity prices throughout 2016 – 2020. It also led to a visible structural shortage of hedge contracts in the SA region (see especially Simshauser, 2019; Flottman et al., 2024).

2.2 Primer on electricity derivatives

The need for electricity derivatives in an energy-only electricity market arises from two interconnected factors. First, firms benefit from hedging as excessive volatility increases the risk of financial distress and may lead to suboptimal investment (Bessembinder & Lemmon, 2002). Second, energy-only markets with high market price caps are inherently volatile due to the nature of spot markets (Wilson, 2002) and demand response is imperfect. Apart from a few sophisticated industrial consumers, the practical evidence is that most market participants are either unaware of the 5-minute clearing process, or are unable (or unwilling) to respond to NEM spot prices.

Energy retailers who provide fixed electricity tariffs to consumers are exposed to volatile spot prices on the buy-side, and typically deploy rigid upper and lower 'hedge limits' to manage excessive spot price risk (Anderson et al., 2007; Boroumand & Zachmann, 2012). Energy retailers in energy-only markets

[1] Inter-regional settlement residue auctions occur up to three years in advance and provide an imperfect inter-regional hedge.

do not necessarily aim for 100% hedge cover under all circumstances[2] – this typically being uneconomic. But retailers must be *substantively hedged* as Section 2.3 later explains vis-à-vis managing through market shock events.

On the other hand, capital-intensive generators are burdened with high fixed and sunk costs (including rigid debt repayment schedules) meaning they also face limits to spot price exposures – boards and banks invariably require some limited level of predictable revenue. Given mirror-image risks of retailers and generators, there are clear incentives provided for active on-market derivative transactions.

The dominant derivatives traded in Australia's NEM are (1) Swaps, (2) $300 Caps, and (3) run-of-plant PPAs. Electricity Swaps are similar to financial markets swaps of all kinds whereby the holder receives a fixed price for a (nominal) quantity whilst the receiving party pays the spot price (Deng & Oren, 2006). In the NEM, (baseload) Swap contracts provide price certainty for up to 3 years (i.e. the approximate length of the NEM's liquid forward market) and are therefore frequently sold by baseload generators and purchased by energy retailers. Electricity Swap prices are mean-reverting and in equilibrium should reflect entry costs of base load plant or equivalent (Simshauser & Gilmore, 2022).

A $300 Cap contract is an option contract which – as the name suggests – places a Cap of $300 on spot price exposures for the purchaser. A Cap contract requires the seller to compensate the purchaser each time spot prices exceed the Cap strike price for the specified volume. In return, the seller receives the Cap premium (McConnell et al., 2015). Consequently, the market for $300 Caps is the (energy-only) NEM's equivalent of a forward capacity market – this instrument being perfectly suited to peaking plant. Indeed, the traded price of $300 Caps in equilibrium reflects the entry cost of an Open Cycle Gas Turbine undertaking peaking duties (see Simshauser, 2020).

PPAs require no introduction. But, it is worth noting that the NEM market convention is based on a 'run-of-plant' structure, meaning if a renewable generator is constrained off for any reason, it does not receive any compensating payment. A current trend in the NEM for renewable projects is ~75% PPA coverage, and by implication, 25% merchant or spot market exposure (see Flottmann et al. 2022; Gohdes et al. 2022, 2023).[3]

2.3 Nature of the potential CfD problem

A visible trend across global energy markets has been 'hybridisation' – where government-initiated CfD auctions accelerate the entry of renewables faster than markets would otherwise deliver, or in the case of technologies such as off-shore wind, underwrite higher-cost technology entry (Gohdes et al., 2023; Keppler et al., 2022; Roques & Finon, 2017).

Government-initiated CfD auctions are first and foremost designed to facilitate renewable entry, and by implication, displace the conventional (i.e. coal) fleet. Often it is the case that little thought has been given to the (unintended, but predictable) follow-on implications to forward markets. Viewed through the lens of the forward market, government-initiated CfDs are 'off-market' transactions since the counterparty is the government (or an equivalent central agency) rather than a market participant (i.e. energy retailer). The only reason this matters at all is the potential impact on hedge markets, and in turn, the functioning of contestable retail supply markets, and consumer prices.

[2] The risk-neutral hedge position of an energy retailer in a market such as the NEM is generally taken to be 'swap to average load, cap to maximum load', ideally with some level of vertical integration or weather derivatives to manage peak loads. See Simshauser (2021) for a quantitative example.

[3] In contrast to run-of-plant PPAs, Swap and Cap derivative contracts require plant (i.e. the seller) to take on volume risk (Flottmann et al., 2022; Simshauser, 2018, 2020). A portfolio of derivative contracts is the standard position of the thermal fleet, and increasingly combined with renewable portfolios (see Simshauser, 2020).

In the early stages of a market transformation, it hardly matters who the counterparty for new entrant VRE projects is. With early auctions, it is usually the case that the incumbent (conventional) generation fleet remains in service along-side the emerging renewables fleet. This produces a surplus of energy (and merit order effects) with no loss of coal plant hedge contract capacity. However, during the middle- and latter-stages of a supply-side transformation – as coal plant exits – so too does their hedge contract capacity as South Australia suddenly discovered in 2016. And unless government-initiated (i.e. off-market) CfDs have been carefully written, a structural shortage of primary issuance hedge contract capacity is more than a theoretical possibility.

How might this occur? Government-initiated auctions are dominated by two-way fixed price CfD instruments. How a two-way fixed price CfD works is the crucial element – renewable project proponents receive a top-up whenever the spot price falls below the designated strike price, and conversely, make payments back to government whenever the spot price rises above the strike price (Wild, 2017). This mechanism provides guaranteed returns for VRE projects and ensures 'bankability' and subsequent entry. Above all, the renewable project with the fixed price CfD is well and truly 'hedged'. In this classic case, this two-way fixed price CfD is first and foremost a derivative, and has the (unintended) effect of removing the project from primary issuance forward market because the power project – being fully hedged by the CfD – *cannot* hedge its output twice.

To see why this is the case, consider the following example of revenues for a new entrant renewable project. In an energy-only market, the revenue settlement for a renewable project in year n with a two-way fixed price CfD is set out in Equation (1):

$$Rev_n = Spot_n + CfD_n \mid Spot_n = \sum(q_n^t \cdot p_n^t) \ \wedge \ CfD_n + \ \sum\left[q_n^t \cdot \left(p^{CfD} - p_n^t\right)\right]. \qquad (1)$$

The 5-minute spot revenues throughout year n $(Spot_n)$ are accumulated according to the sum of dispatched output q_n^t in trading interval t and relevant spot price, p_n^t. To this, the two-way CfD_n settlement is added – the key issue being the two-way settlement. This structure produces highly stable revenues – consider a 500MW wind project (~35% Annual Capacity Factor) in the Queensland region using historic NEM market data from 2020-2022 and a government-initiated CfD with a strike price of $89/MWh (see Table 1a). As can be seen, the revenue certainty that comes with a run-of-plant, fixed price two-way CfD[4] for the wind farm via Equation (1) ameliorates any real project revenue volatility (+/-2%). In other words, the two-way fixed price CfD does its job – project revenues are hedged.

Table 1a: 500MW wind farm in Queensland (2020-2022) with a CfD

Eq.(1)		2020	2021	2022	
p_n	($/MWh)	53.97	107.97	162.00	
q_n	(GWh)	1,520	1,518	1,560	
Spot	($m)	82.0	163.9	252.8	
+ $89 CfD	($m)	53.3	-28.8	-113.9	
= Revenue	($m)	$135.3	$135.1	$138.9	(+/- 2%)

If a renewable project were to simultaneously commit to (1), a government-initiated fixed price CfD, *and* (2) an on-market PPA_n, the renewable project would be *double-hedged* per Equation (2):

[4] An on-market PPA produces the same result.

$$Rev_n = Spot_n + CfD_n + PPA_n \mid Spot_n = \sum(q_n^t \cdot p_n^t) \ \wedge \ CfD_n + \ \sum\left[q_n^t \cdot \left(p^{CfD} - p_n^t\right)\right] \wedge \ PPA_n + \sum[q_n^t \cdot (p^{PPA} - p_n^t)]. \quad (2)$$

The key issue here is that Equation (2) amplifies the revenue volatility of the renewable project – the exact opposite outcome sought by project banks and renewable equity investors. Table 1b illustrates this by adding an on-market PPA at $90/MWh to the 500MW wind farm example:

Table 2b: Double-hedged 500MW wind project (2020-2022) - CfD & PPA

Eq.(2)		2020	2021	2022	
p_n	($/MWh)	53.97	107.97	162.00	
q_n	(GWh)	1,520	1,518	1,560	
Spot	($m)	82.0	163.9	252.8	(+/- 49%)
+ $89 CfD	($m)	53.3	-28.8	-113.9	
+ $90 PPA	($m)	54.8	-27.3	-112.4	
= Revenue	($m)	$190.1	$107.8	$26.5	(+/- 75%)

It can be seen in Table 1b that when underwritten by a two-way fixed price CfD and then committing the output a second time in forward markets via a PPA – unsurprisingly – the volatility of the wind project's annual revenues is amplified very considerably (+/-75%). In fact, double hedging produces far more revenue volatility for the 500MW wind project than no hedge at all (+/-49%).

As an aside, using a contemporary project financing for the 500MW wind farm in Table1b[5], if annual revenues were to fall below $88m, the project debt would go into default. Needless to say, at $26.5 million (Table 1b, 2022 result), the project would be in financial distress. Evidently, renewable projects cannot commit to hedging output twice and therefore, a government-initiated two-way fixed price CfD is capable of sterilising the 'hedge contract capacity' of renewable projects from the over-the-counter market.

However, there are CfD designs that may facilitate on-market hedge capacity. This might include revenue collar structures with an obligation to undertake on-market hedging – our substantive point being that the CfD design-element is critically important. Recent government-initiated auction iterations in the NEM's New South Wales region and by the Commonwealth *have* focused carefully on CfD design and potential interactions with the forward hedge market. And globally, there are policies which limit the impact to forward markets from government contracts, for example, France's guarantee allows customers to purchase a portion of their electricity (via retailers) from Électricité De France's nuclear generation fleet (Batlle et al., 2022).

Conversely, earlier Australian CfD auctions focused strictly on physical renewable generation entry via two-way fixed price CfDs, with no consideration of flow-on impacts to forward markets, and in turn, the contestable retail market. If two-way fixed price CfDs adequately hedge a renewable project and government is the counterparty, then the energy output of the VRE project is extracted from the forward markets. And, if fixed price CfDs sufficiently dominate transactions, it may create a genuine scarcity of forward contracts. Scarcity may then create two separate policy issues:

1. Scarcity of forward contracts may drive rising contract risk premiums. If hedge costs increase due to rising contract premiums, higher prices would be passed on to customer retail bills (Flottmann et al., 2024). It is ultimately the consumer who is most impacted by access to contract liquidity, and an energy retailer's ability to adequately hedge a given customer load.

[5] The assumption here is $3300/kW and a project financing of ~65% gearing with 2024 capital market conditions.

2. We noted in Section 2.2 that an active 'primary issuance' forward market for contracts is critical for retailers and especially non-vertically integrated second tier retailers in order to hedge customer loads. Any structural shortfall or scarcity means second tier retailers (in particular) may be forced to increase spot market exposures beyond prudent levels – a risky strategy in markets with very high Market Price Caps.

These two issues have occurred in Australia and elsewhere, with constrained access to forward markets by retailers identified in Jamasb et al. (2023); Schittekatte and Batlle (2023) and Flottman et al. (2024) across various jurisdictions. Inadequate hedging practices are associated with retailer bankruptcies. Bankruptcies are most pronounced during crisis events as occurred in Great Britain (2022, Russia-Ukraine war) and in Texas ERCOT (2021, storm Uri) as Mays et al., (2022) and Schittekatte & Batlle (2023) explain.

On the one hand, some minimum level of bankruptcy in any commodity or service market provides evidence of efficiency through removal of poorly managed firms. On the other, the fact that not all retailers experienced bankruptcy during these market extremes tells us that bankruptcy is not inevitable during extreme events, and periods of elevated volatility are ultimately manageable. Above all, bankruptcies driven by policy-induced structural shortages of forward contracts are not indicative of a well-functioning market for an essential service like electricity.

Finally, it is to be noted that two-way fixed price CfDs are not thought to amplify the volatility of electricity spot markets per se. Spot market volatility has been shown to increase with increasing VRE (see Mwampashi et al. (2021); Rai and Nunn (2020); Rintamäki et al. (2017)), but it is not the CfD instrument causing this volatility (i.e. on-market PPAs would have produced the same effect). Conversely, VRE impacts on spot markets may have *mixed impacts* on forward contract premiums depending on the market structure and percentage of VRE present as implied in point #1 above (Huisman et al., 2021; Peura & Bunn, 2021). But two-way fixed price CfDs may impact energy & capacity markets (UK & EU) differently to energy-only markets (ERCOT & NEM) (see for example Schlecht et al., 2024; Veenstra & Mulder, 2024).

In the present analysis, our task is to model the 'primary issuance' or fundamental market supply of forward market Swaps, $300 Caps and PPAs in each of the NEM's main zonal markets of Queensland, NSW, Victoria and South Australia. We do so with- and without government-initiated fixed price CfDs in order to examine whether forward market shortages are predictable. This leads us to our model, and associated data.

3. Models and Data

To adequately determine the impact of exiting thermal generation on the existing supply of 'primary issuance' hedge contract capacity within an energy only market, a power system simulation model known as NEMESYS has been used. The present model replicates that used in Simshauser (2018, 2019) but in expanded form to cover all NEM mainland zones. The model is a security constrained, unit commitment model with 30-minute price formation based on uniform first price auction clearing mechanism, consistent in the NEM. NEMESYS assumes perfect competition, a copperplate transmission system and perfect ramp rates with free entry & exit such that the market may install any combination of differentiable capacity required to satisfy equilibrium conditions. The modelled system begins with thermal plant only (i.e. coal and gas). We then introduce VRE progressively with the thermal plant stock adjusting accordingly, with coal plant exiting and gas turbine plant increasing as required to ensure reliability constraints are met.

Two scenarios are run in the first instance using the NEM's Queensland's region to tune the model. The first scenario examines a VRE buildout with government-initiated CfDs and no recycling of auction contracts. Our second scenario then examines a 100% CfD recycling scenario (essentially seeking to replicate the work in Simshauser, 2019). We then expand the sequence and findings by examining multiple regional markets simultaneously (i.e. the remaining mainland NEM jurisdictions).

3.1 NEMESYS model logic

Generation technologies and associated plant costs are essential inputs to a unit commitment model. To get optimal results unit marginal running costs ν^j and plant fixed costs φ^j are key inputs. The model logic has been derived from Simshauser (2019) with modifications and will be outlined within this section.

An entry cost model derives generalised generation technology average total costs $p^{i\varepsilon}$ and total revenues including profit R^i for a set output o^i.

$$\left(\nu^i \times o^i \right) + \varphi^i \equiv R^i | \, R^i = p^{i\varepsilon} \times o^i, \qquad (1)$$

The model orders plant capacity according to strict merit order based on marginal running costs and dispatches them subject to the specified security constraints and differential equilibrium conditions.

Let H be the ordered set of all half-hourly periods.

$$n \in \{1 \ldots |H|\} \wedge h_n \in H, \qquad (2)$$

Let E be the set of all electricity consumers in the model.

$$k \in \{1 \ldots |E|\} \wedge e_k \in E, \qquad (3)$$

Let $C_k(q)$ be the valuation that consumer segments are willing to pay for quantity q MWh of power. NEMESYS assumes demand in each period n is independent of demand in other periods. Let q_{nk} be metered quantity consumed by customer e_n in each period h_k expressed in MWh. Let Ψ be the set of existing installed power plants and available augmentation options for each relevant scenario.

$$i \in \{1 \ldots |\Psi|\} \wedge \psi^i \in \Psi, \qquad (4)$$

As outlined in Equation (1), let φ^i be the fixed operating and sunk capacity costs and v^i be the (unit) marginal running cost of plant ψ^i respectively. Let o^i be the maximum continuous rating of power plant ψ^i. Power plants are subject to scheduled and forced outages. F(n, i) is the availability of plant ψ^i in each period h_n. The outage rate profile F(n, i) is calculated using a randomised integer between 0 and 1, if the integer is greater than the outage rate, the unit is in-service. If less than the outage rate, the unit is considered unavailable.

Annual plant availability is therefore:

$$\sum_{j=0}^{|P|} F(n,i) \, \forall \, \psi^i, \qquad (5)$$

Let o^i_n be the quantity of power produced by plant ψ^i in each period h_n.

The objective function seeks to maximise producer and consumer surplus, which is given by the integral of the aggregate demand curve less power production costs.

$$Obj = \sum_{n=1}^{|H|} \sum_{i=k}^{|E|} \int_{q=0}^{e_k} C_k(q)dq - \sum_{n=1}^{|H|} \sum_{\psi=1}^{|\Psi|} (o_\psi \cdot v^i) - \sum_{\psi=1}^{|\Psi|} (\varphi^i), \tag{6}$$

subject to

$$\sum_{i=1}^{|E|} q_{kn} \leq \sum_{\psi=1}^{|\Psi|} o_{\psi i}^{\wedge} 0 \leq o_n^i \leq F(n,i)^\wedge 0 \leq o_n^i \leq \overline{o^i}. \tag{7}$$

A full list of model inputs can be found in
Table 2.

Table 3: Model input symbols and definition.

Symbol	Definition
n	Number of half hourly periods
i	Number of scenarios
ν^i	Marginal running costs
φ^i	Fixed costs
$p^{i\varepsilon}$	Generalised technology long run cost
R^i	Total revenues including profit
o^i	Output
H	Half-hourly periods
E	Electricity consumers
C_k	Valuation that consumer segments are willing to pay
q	Quantity
q_{nk}	Metered quantity consumed
Ψ	Existing installed power plants
F(n, i)	Annual plant availability

3.2 Model inputs

The important features utilised in the model are outlined as follows: five generation technologies may be deployed in the power system including incumbent black coal plant, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT) and VRE (wind and solar PV). Thermal plant is modelled using generalised entry costs whilst VRE is assumed to be project financed and underpinned by government-initiated CfDs.

Plant and technology cost assumptions are illustrated in Table 3 with financial parameters following Aurecon (2023) and emission estimates from Elliston et al. (2014). To simplify the modelling process in regional scenarios, capital costs are held constant while plant size, unit fuel costs, wind and solar traces, and load curves are representative of each of the four zonal markets. Variation in plant sizes reflects the average for each region or zone.

Once combined, these data provide all the necessary inputs to produce generalised estimates of Average Total Cost for incumbent coal plant and generalised entry costs for new entrant plant including CCGT, OCGT, wind and solar PV. These are then utilised within the NEMESYS model logic to produce the optimal plant mix.

Table 4: Plant cost assumptions

Technology	Capital cost	Unit size	Variable O&M	Fixed O&M	Useful life	Heat rate	Fuel cost	Auxiliaries	Emissions
	($/kW)	(MW)	($/MWh)	($M pa)	(Yrs)	(GJ/MWh)	($/GJ)	(%)	CO_2 t/MWh
Coal	4,680	450	4.46	25.364	30	9	3	0.96	0.8
NGCC	1,950	400	3.9	4.624	25	7	8	0.98	0.4
OCGT	1,040	250	7.7	2.705	25	12	12	0.99	0.76
Wind	2,875	480	-	12.7	30	-	-	0.97	-
Solar	1,200	200		2.5	30	-	-	0.97	-

Source: Aurecon (2023)

4. Model results – general contract market

The NEMESYS model described in Section 3 was initially populated with plant costs from Section 3.2 and half hour load data derived from a random year of power system aggregate final demand from the Queensland region of the NEM. We assume an own-price elasticity of demand of -0.10 for modelling purposes, in line with the assumption contained in Simshauser (2018, 2020).

To keep results tractable, a single non-interconnected Queensland power system is modelled. The level of VRE within the system is exogenously determined to achieve a certain market share in line with current Australian Commonwealth & State government policy objectives. The QLD scenario commences with a fleet of thermal plant stock and 0% VRE, and progressively iterates to 60% VRE market share. An overview of Queensland model results is presented in Table 4.

Table 5: Overview of key model results

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	54,574	56,270	1,696
Maximum Demand (MW)	9,369	9,660	291
Plant Capacity			
Coal (MW)	5920	2,220	- 3,700
CCGT (MW)	800	1,800	1,000
OCGT (MW)	3740	5,780	2,040
Wind (MW)	0	8,191	8,191
Solar (MW)	0	5,459	5,459
Supply of Primary Hedges (MW)	9,350	8,720	- 630
Underlying System Price ($/MWh)	96.2	75.1	- 21
Unserved Energy %	0.001%	0.001%	

The results reflect an initial maximum demand of ~9,400 MW (0% VRE) and following a rise in VRE to 60% market share, maximum demand rises to ~9,700[6] following the fall in unit prices. The opening

[6] A sensitivity was conducted with stagnant demand. The results indicated a slight improvement in magnitude of contract shortfalls, but it did not materially change the results. In summary, the problem we have identified is inherently structural.

plant stock in the base scenario is predominantly coal plant, and at ~5,900 MW accounts for 57% of capacity in the system. A reserve margin to account for plant outages equates to ~11% noting that unserved energy of 0.001% remains within the NEM's stated reliability criteria of <0.002%.

To meet a 60% VRE market share, ~5,500 MW of solar and ~8,100 MW of wind are added to the aggregate plant stock, and under optimal conditions in equilibrium, -3,700 MW of coal plant exits the market. To maintain system reliability, +1,000 MW of new CCGT and +2,040 MW of OCGT plant is added to the plant stock.

CCGT and OCGT plant exhibit annual capacity factors (ACFs) of 51% and 10% respectively at 0% VRE market share, which fall to 40% and 7% at 60% VRE market share. It is important to highlight that mid-merit and peaking plant have been modelled as CCGT & OCGT but could also comprise some level of pumped hydro or battery storage. For the purposes of modelling forward contracts, non-duration limited CCGT & OCGT plant were used. In this way, modelling provides an indication of maximum contract volumes which may be offered to the market under optimal conditions as CCGT & OCGT plant are not theoretically limited in operational run-times in the same way pumped hydro and battery plant may be.

4.1 Queensland scenario contract market results

In the Queensland scenario, the quantity of 'primary issuance' hedge contract capacity from the thermal generation fleet needs to be determined. For this purpose, we rely on the methodology in Simshauser (2019) – which in turn is broadly consistent with the findings in Anderson et al. (2007). To summarise, this involves a Monte Carlo-based simulation of coal and gas turbine availability and identifying the 90th percentile result for a given portfolio of generation plant (see Fig.2). Queensland's 10,500MW opening plant stock (from Table 3) has been nominally split into three rival (and diversified) generation portfolios, designed to replicate market conditions in Queensland (which has three large portfolio generators, albeit with a number of fringe generators). The three modelled portfolios are clearly identified in Table 5 for both 0% VRE and 60% VRE market shares.

Table 6: Portfolio capacity and change in capacity for dispatchable units

VRE Market Share		0%	60%	Change
Portfolio 1	Coal Capacity (MW)	2200	740	-1460
	CCGT Capacity (MW)	400	600	200
	OCGT Capacity (MW)	1360	2040	680
	Total	3960	3380	-580
Portfolio 2	Coal Capacity (MW)	1850	740	-1110
	CCGT Capacity (MW)	200	600	400
	OCGT Capacity (MW)	1190	1870	680
	Total	3240	3210	-30
Portfolio 3	Coal Capacity (MW)	1850	740	-1110
	CCGT Capacity (MW)	200	600	400
	OCGT Capacity (MW)	1190	1870	680
	Total	3240	3210	-30

In the base or '0%' VRE market share scenario, Table 5 notes the first generator portfolio commenced with 3,960 MW of installed capacity, and the two remaining portfolios had 3,240 MW each. As outlined above, the Monte Carlo-based plant availability duration curves were constructed in a similar manner to Simshauser (2019), with the 90th percentile[7] used as the hedging 'setpoint' and is illustrated in Figure 1. Note from Fig.2 the supply of hedges from Generator 1 equates to ~3,600MW, and ~2,700MW for Generators 2 and 3.

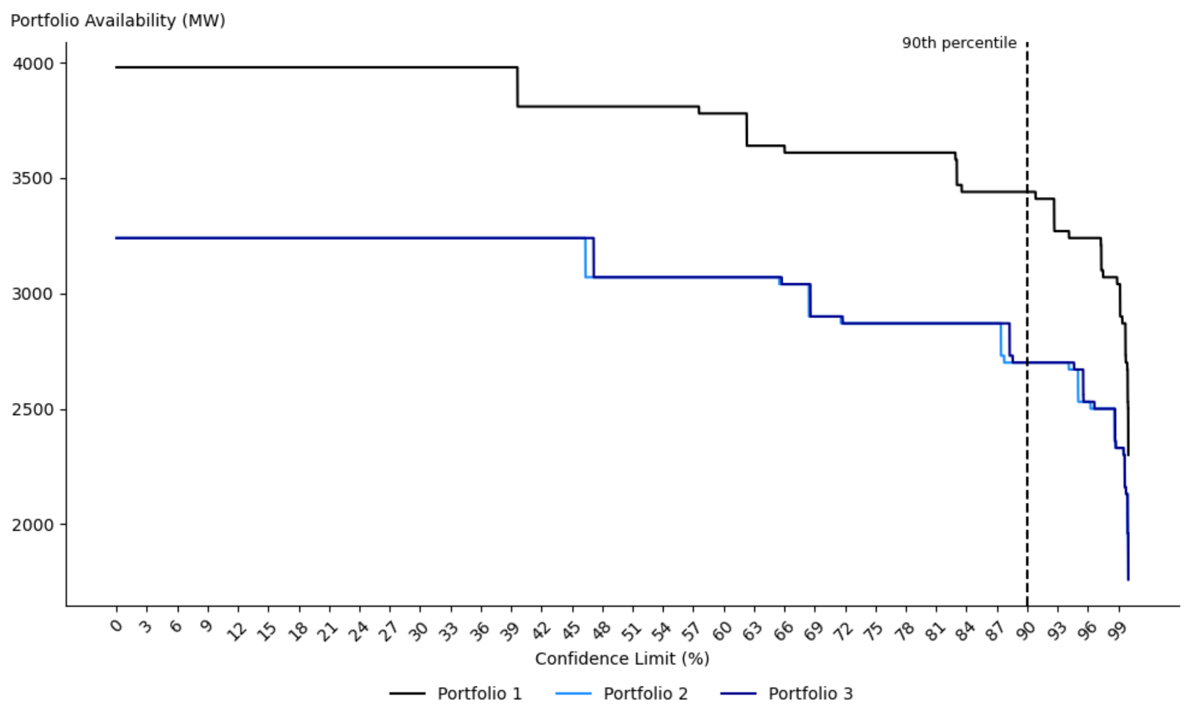


Figure 1: Primary supply of hedge contracts at 0% VRE market share

The change in portfolio capacity as VRE market share is increased from 0% to 60% is also shown in Table 5. Here, each portfolio loses the majority of its coal capacity, whilst building additional CCGT or OCGT plant capacity. Portfolios are visibly contracting in aggregate. The new VRE is not distributed amongst the portfolios because they are not assumed to enter by way of *on-market* PPA transactions, but rather, via *off-market* government-initiated CfDs. Consequently, the new capacity does not form part of the incumbent generation portfolios.

Note in Fig.3 the stacked bar series representing aggregate thermal capacity at 0% market share (x-axis) is ~10,500MW (y-axis). With this plant stock, the line series representing maximum demand is ~9,000MW and this also matches the aggregate supply of 'primary issuance' hedge contract capacity. But as renewable market share increases towards 60% along the x-axis, the supply of primary issuance hedge contract volumes declines, just as maximum system demand increases, albeit modestly, in line with elasticity effects. By 60% VRE, the physical system maintains reliability of supply but from a systemic perspective, a cumulative shortfall in primary issuance hedge contracts emerges, and accounts for 9% of the theoretical demand for hedge contracts from retail suppliers.

With a VRE market share of 60%, large loads and retail suppliers would in theory be forced to take on some level of spot market exposures due to the shortfall in primary issuance contracts. It is to be noted that structural shortfalls of hedge contract capacity invariably result in the exit of speculative participation in forward markets as explained in Simshauser (2019), and so we should not assume proprietary traders will fill this gap – the reason being the primacy of liquidity for their own risk mitigation (see also Goldstein and Hotchkiss, 2020). This is far more than a theoretical observation

[7] A sensitivity of traditional N-1 hedging strategy was also conducted. The results showed an increased decline in primary issuance hedge contract shortfalls.

and is exemplified by experiences in the South Australian region of the NEM – where only a few remaining generators with physical asset backing were able to sell forward contracts, and at significant premiums, as identified by Flottmann et al., (2024).

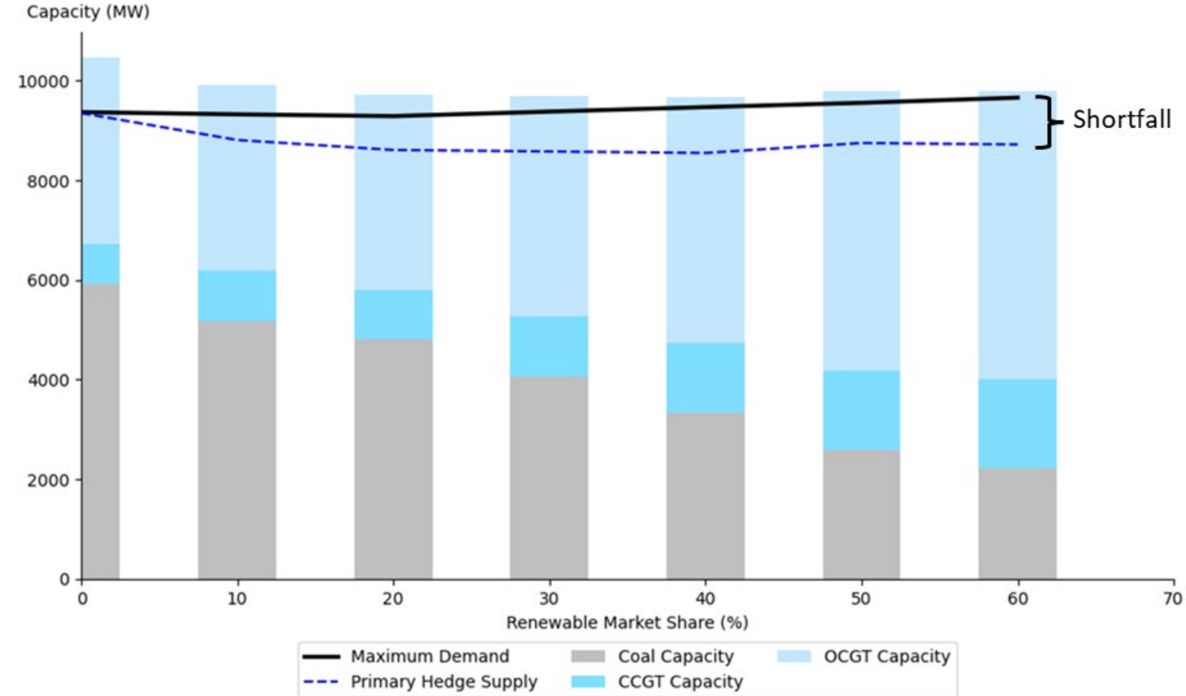


Figure 2: QLD model results primary supply of hedge contracts vs maximum demand (0% - 60% VRE)

As a final observation, note in Fig.3 that the hedge contract shortfall (see dotted blue line) progressively deteriorates from 0-40% on the x-axis, but then appears to stabilise between 40 – 60% VRE market share. The reason for this plateauing is that diversity of VRE output seems to reach its maximum in the Queensland region at ~40%. Thereafter, each MW of coal exit needs to be matched by a MW of dispatchable plant entry (i.e. CCGT & OCGT) in maintain power system reliability.

4.2 VRE contract supply levels

The analysis thus far has assumed all VRE plant enters through off-market government-initiated CfDs. This led to a market shortfall – and is perhaps not entirely surprising. What happens if all VRE plant enters via on-market PPAs, or the style of CfDs has been carefully designed to encourage recycling of the CfD hedge capacity in some way? Are hedge contract shortfalls inevitable with the loss of baseload capacity and the rise of intermittent capacity?

Under a 100% ‘on-market’ or ‘CfD recycling’ VRE scenario, drastic change occurs as illustrated in Figure 3. Primary issuance hedge contract shortfalls are largely mitigated if all new entrant plant enters via on-market contracts (or are recycled) rather than off-market CfDs. As with the physical market, the loss of coal plant is matched by the gains from entering VRE and gas turbine plant capacity. In Figure 3, the improvement is clearly seen as the available VRE plant capacity increases.

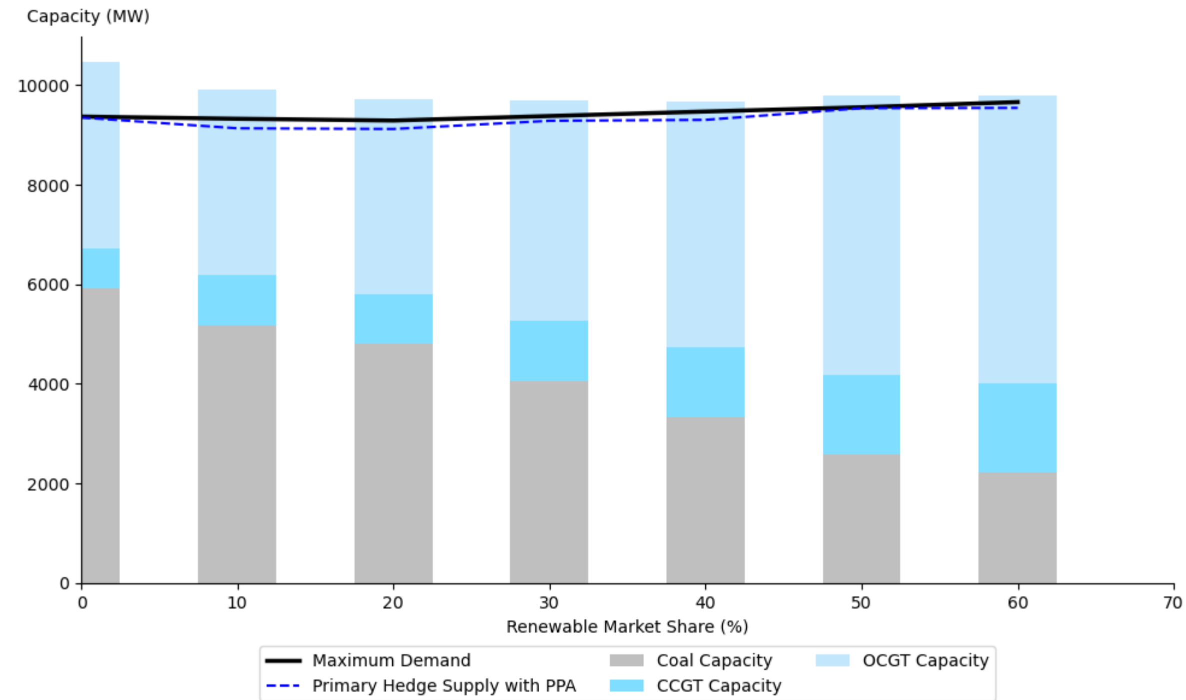


Figure 3: On market PPAs with 90th percentile thermal hedge supply (dotted blue line) against QLD region demand

To summarise, on-market transactions or active recycling of CfDs in the NEM's Queensland region ensures the hedge market re-balances itself, even with the loss of the traditional baseload hedge contract providers (i.e. coal plant) and it does so in a manner identified in Simshauser (2020), through run-of-plant PPAs with dispatchable plant synthetically recreating baseload swaps. The analyses contained above in Section 4.1 (Fig.3 off-market CfDs) and Section 4.2 (Fig.4 on-market PPAs) will now be replicated throughout Section 5 to examine the remaining three mainland NEM regions – with surprising results for at least one NEM region.

5. Regional contract shortage results

The scenario outlined in Section 4 was designed to be a non-interconnected system in an energy only market using Queensland data – noting basis risk exists between regions. Given the results, it is valuable to explore how 'primary issuance' hedge contracts within each remaining NEM mainland region (i.e. NSW, VIC, SA) evolve through advancing stages of decarbonisation.
Table 6 identifies the size of each unit and the associated fuel costs used in the analysis below.

Table 7: Region capacity and SRMC for dispatchable units

Technology	NSW		QLD		VIC		SA	
	Unit Size (MW)	SRMC ($/MWh)	Unit Size (MW)	SRMC ($/MWh)	Unit Size (MW)	SRMC ($/MWh)	Unit Size (MW)	SRMC ($/MWh)
Black Coal	700	21.37	370	21.37	485	10.26	260	25.64
NGCC	400	56.54	200	56.54	400	63.61	300	70.68
OCGT	200	151.70	170	151.70	200	151.70	170	163.70

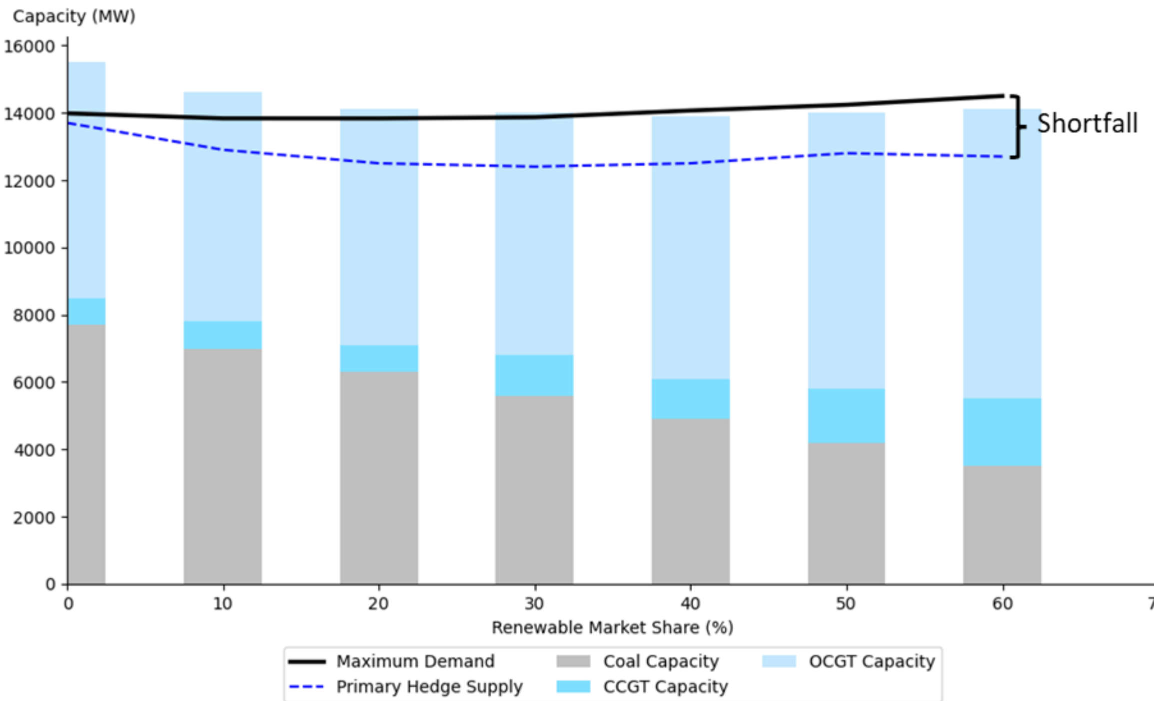
5.1 New South Wales primary issuance hedge contract shortage

NSW is the most populous state of the NEM and as a result has the highest historical demand levels and a large coal fleet. Each coal unit is at least 660 MW with the average being 700 MW. Compared to Queensland where the average unit is nearly half the size, this disparity could have adverse impacts on contract supply (i.e. lumpier exit).

Model results for NSW in Table 6 sees maximum demand rise by ~600 MW as VRE market share increases from 0 – 60%. In the model, 4,200 MW of coal capacity exits as ~10,800 MW of wind and ~4,500 MW of solar enter, along with 1,200 MW of CCGT plant and 1,600 MW of OCGT peaking capacity. Modelling suggests mid-merit plant runs at an ACF of 36% at 60% VRE, whilst peaking plant run at 5% ACF. In this scenario, the primary supply of hedge contracts would fall by 1,000 MW leaving a hedge contract shortage of 12% of maximum demand at 60% VRE market share (Figure 4A).

Table 8: Overview of key NSW model results.

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	70,552	73,144	2,592
Maximum Demand (MW)	13,986	14,500	514
Plant Capacity			
Coal (MW)	7,700	3,500	- 4,200
CCGT (MW)	800	2,000	1,200
OCGT (MW)	7,000	8,600	1,600
Wind (MW)	0	10,780	10,780
Solar (MW)	0	4,522	4,522
Supply of Primary Hedges (MW)	13,700	12,700	- 1,000
Underlying System Price ($/MWh)	99.74	70.4	- 29
Unserved Energy %	0.001%	0.001%	



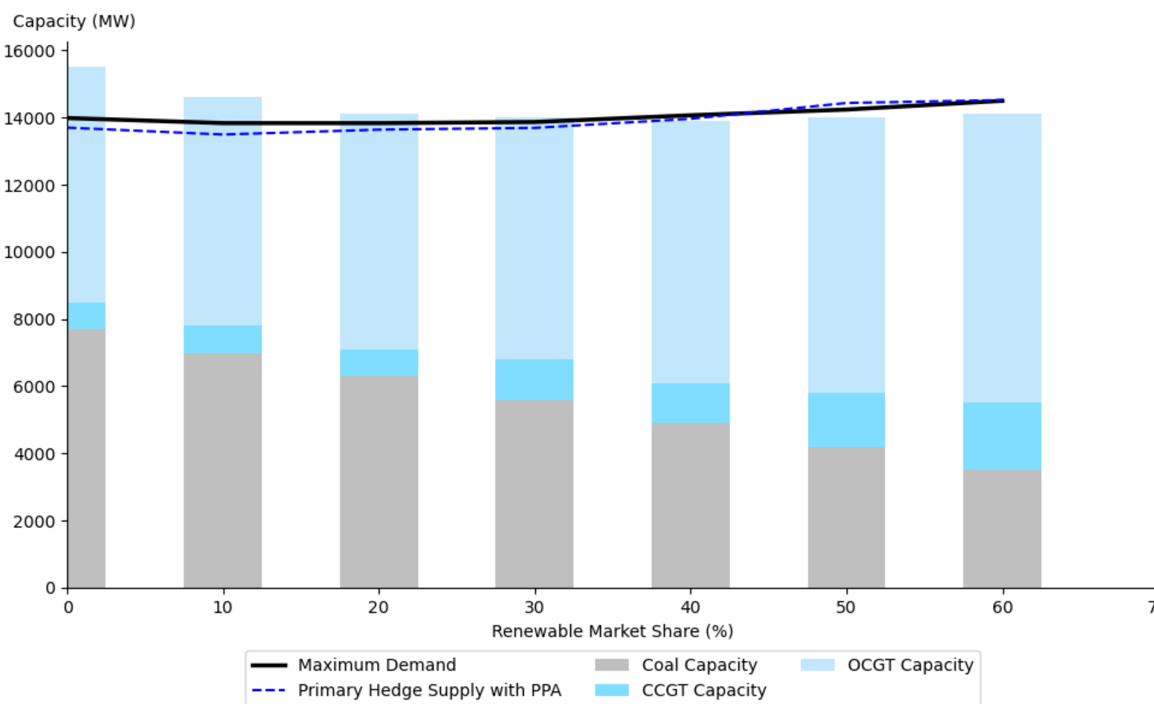


Figure 4: A (Top) NSW model results thermal primary supply of hedge contracts vs maximum demand (0% - 60% VRE). B (Bottom) NSW model results thermal primary issuance hedge supply and on-market PPA hedge supply

The impact of VRE being underwritten by CfDs is particularly important for NSW, where a state government-initiated scheme exists to incentivise VRE deployment along with an overlapping Commonwealth scheme. The NSW CfD scheme comprises Long Term Electricity Supply Agreements or 'LTESAs' and essentially operates as a put option (or floor) over VRE project revenues. When activated, LTESAs do not easily facilitate 'portfolio hedging' because winning participants must ensure their revenues are traceable – and this means any on-selling of the capacity must be sold to a third party, not within a firms' own dedicated hedge portfolio for its own customer loads (due to the risk of 'un-traceability', that is, the usual *transfer pricing risks* within a single firm). When not exercised, the LTESA CfDs do not appear to preclude a portfolio developer or utility from forward selling the run of plant output from a renewable project into forward markets per se, including as an internal portfolio hedge. However, as a taxpayer-wrapped put option or floor on project revenues, it may also encourage greater risk taking and spot market participation – the results in Gohdes et al. (2023) very clearly suggesting this to be profit maximising compared to writing on-market PPAs. Conversely, if 100% of VRE plant CfDs are recycled or sold via on-market PPAs, contracts shortfalls are mitigated as Figure 4B illustrates.

5.2 Victorian primary issuance hedge contract shortage

Next, we analyse Victorian primary issuance hedge contract market capacity. The expected shortage is analysed using the same financial inputs as in the previous three modelled scenarios based on information from Section 3 but as outlined in Section 2.1, Victorian coal units use lignite, a far cheaper fuel source. As a result, unit fuel costs have been significantly reduced in the Victorian scenario noting Australia's NEM does not have an explicit price on CO2 emissions. Thermal unit size also been adjusted to represent the average plant size of units in Victoria.

Model results in Table 7 indicate ~6,800 MW of wind and ~3,300 MW of solar capacity is added to the region along with 400 MW of CCGT and 200 MW of peaking OCGT capacity to achieve 60% renewable energy and maintain a secure system. This capacity addition allows for the closure of 2,425 MW of coal capacity. Interestingly, coal closures are lower in VIC as a % of starting capacity compared to the NSW and Queensland regions – which also reflects observed NEM results. This is due to the low fuel costs associated with VIC coal units (and the absence of a price on carbon). However, in closing 2,425 MW of coal capacity the primary supply of hedges falls by ~1,200 MW to ~7,300 MW implying a shortfall of 17% to final maximum energy demand (Figure 5A).

Table 9: Overview of key VIC model results

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	43,418	43,983	565
Maximum Demand (MW)	8,661	8,773	113
Plant Capacity			
Coal (MW)	5,335	2,910	- 2,425
CCGT (MW)	0	400	400
OCGT (MW)	4,600	4,800	200
Wind (MW)	0	6,823	6,823
Solar (MW)	0	3,363	3,363
Supply of Primary Hedges (MW)	8,565	7,310	- 1,225
Underlying System Price ($/MWh)	75.4	55.1	- 18
Unserved Energy %	0.001%	0.001%	

A sensitivity analysis was conducted using a carbon price of $30.5/t[8] of CO_2 applied to all thermal generators in Victoria. Emissions intensities were derived from Table 3 except for coal. As Victoria uses lignite it has a higher emissions intensity therefore an emissions intensity of 1.22 t/MWh was used (Saha et al., 2016; Tian et al., 2010). The results show little change in the contract shortfalls but with higher marginal running cost the model exits more coal, at 3,880 MW. There is also significantly

[8] This price was taken using the $23/t carbon price implemented as part of Australia's carbon tax in 2012 and inflated to 2023 dollars.

more mid-merit plant entry at 1,200 MW. This sensitivity highlights the importance of adequately replacing exiting coal capacity to ensure hedge contracts are maintained at operable levels.

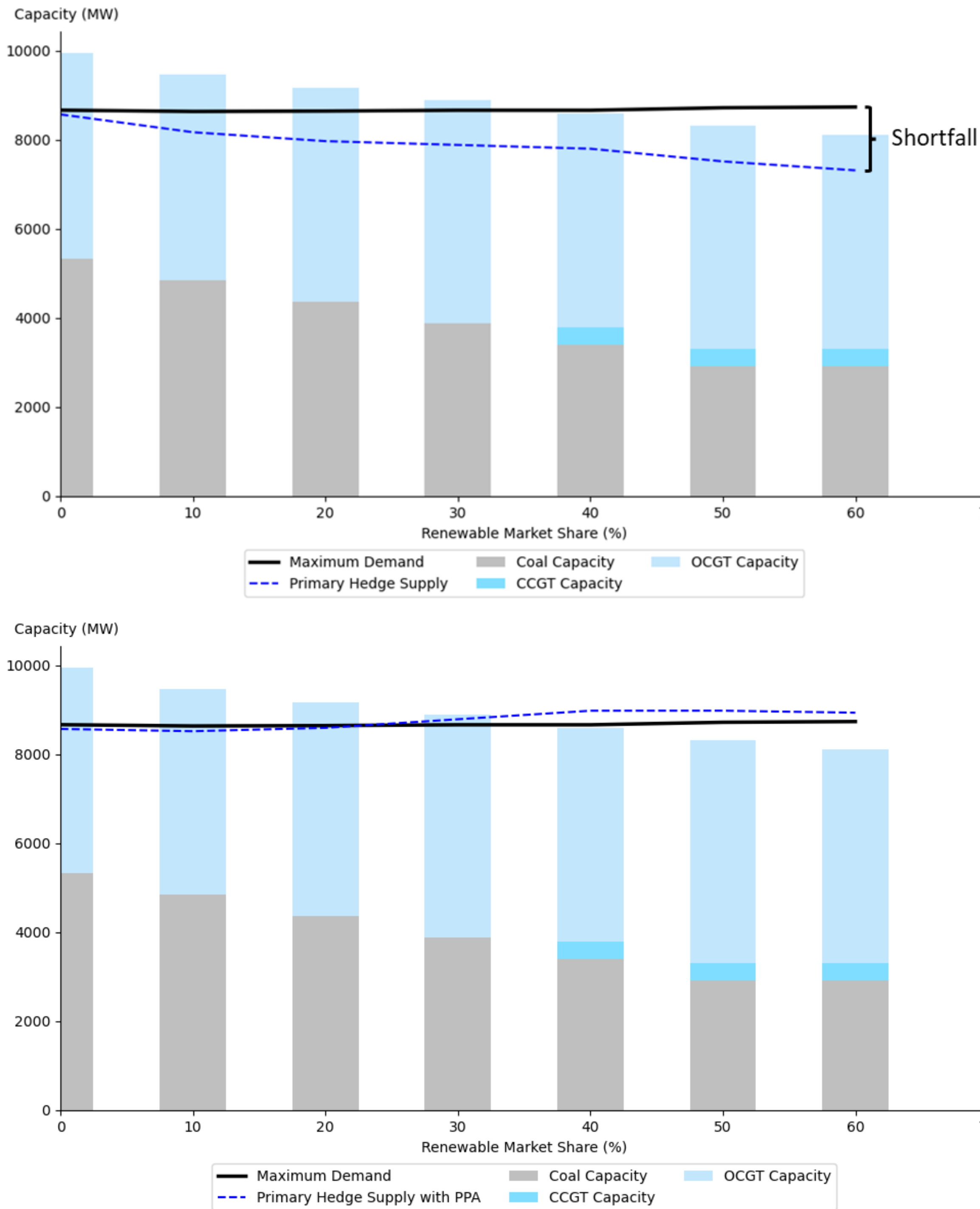


Figure 5: A (Top) VIC model results primary issuance supply of hedge contracts vs maximum demand (0% - 60% VRE). B (Bottom) VIC model results thermal primary issuance hedge supply and on-market PPA hedge supply

Adding VRE capacity via on-market PPAs to the primary hedge supply does significantly improve the growing shortfall such that at 60% VRE market share there is a net positive against maximum demand (Figure 5B).

5.3 South Australian primary issuance hedge contract shortage

The South Australian region has been the fastest to decarbonise its energy mix in the NEM, and globally. This NEM region has already closed all of its coal-fired generation, which occurred when the state had approximately 40% VRE market share (in 2016). To reflect this development, the model has been forced to close coal capacity at the same time to adequately replicate the supply of primary issuance hedge contract capacity available to the region. As with previous analyses, unit size and fuel costs have been changed to reflect the current regional generating capacity.

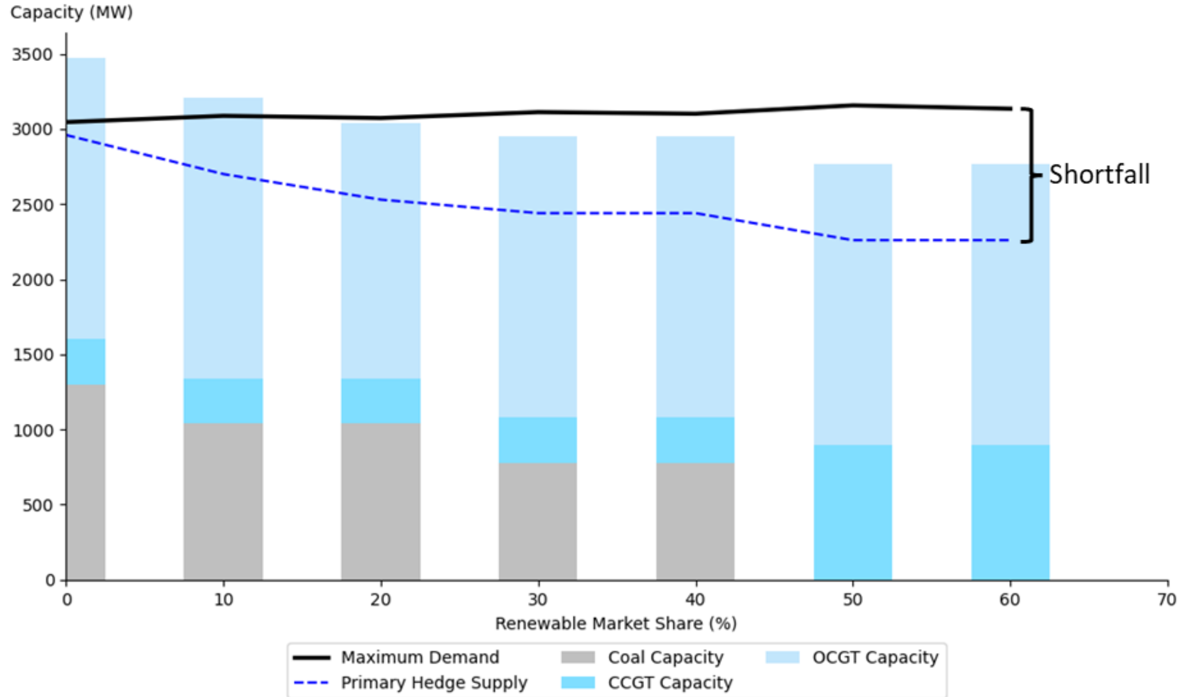
Model results in Table 9 indicate the entry of ~2,000 MW of wind, ~800 MW of solar, 600 MW of CCGT and no peaking OCGT, allowing for the closure of all 1,300 MW of coal capacity. As a result of this coal capacity exiting, ACFs of CCGT plant increase from 45-74% between 30 – 40% VRE market share, but then falls to 52% by 60% VRE market share. Throughout this time, OCGT ACFs are maintained below 10% within expected range.

Primary issuance hedge contract capacity falls by 700 MW, ultimately resulting in a shortage of 26% to maximum demand (Figure 6A). This result presents as the largest proportional shortage of any NEM zonal market modelled. The results are also aligned with market observations contained in Flottmann et al. (2024), where the SA region sees high contract premiums for both Swap and $300 Cap contracts.

When 100% of VRE CfD capacity is recycled to the market or originated via on-market PPAs, the improves from a 26% shortage, but does not completely clear (see Figure 6B). SA seems to be the only NEM region with a structural shortage with 100% on-market PPA transactions. Consequently, the SA market will be highly sensitive to any government-initiated CfD (including those undertaken by other jurisdictions – recall the Australian Capital Territory originated ~1200MW of CfDs, many of which were in South Australia and have not been recycled – and has no doubt contributed to the findings in Flottman et al., 2024). This indicates the SA region may require particular attention to ensure structural shortfalls of hedge contract capacity does not exacerbate an already present problem.

Table 10: Overview of key SA model results

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	11,581	11,956	77
Maximum Demand (MW)	3,046	3,144	20
Plant Capacity			
Coal (MW)	1,300	0	-1,300
CCGT (MW)	300	900	600
OCGT (MW)	1,870	1,870	-
Wind (MW)	0	1,949	1,949
Solar (MW)	0	799	799
Supply of Primary Hedges (MW)	2,960	2,260	-700
Underlying System Price ($/MWh)	86.3	85.0	-3
Unserved Energy %	0.001%	0.001%	



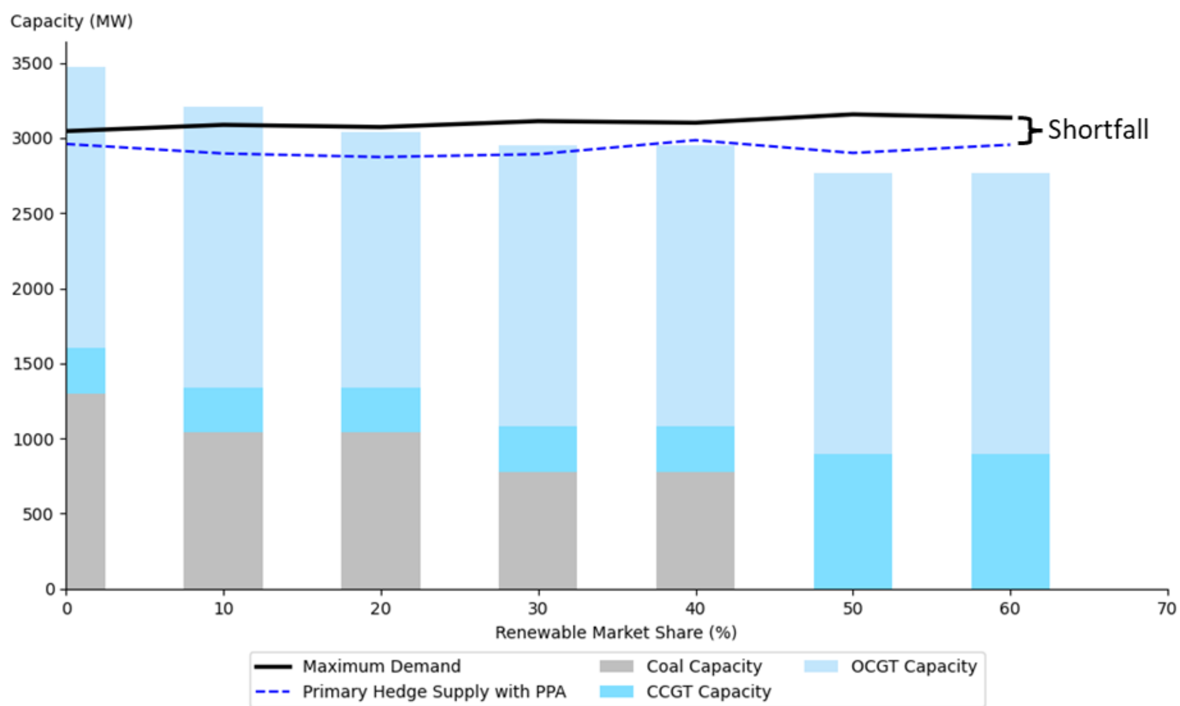


Figure 6: A (Top) SA model results primary issuance supply of hedge contracts vs maximum demand (0% - 60% VRE). B (Bottom) SA model results thermal primary issuance hedge supply and on-market PPA hedge supply

5.4 Is the shortfall a Swap or a $300 Cap problem?

At first glance, given baseload coal plant is exiting the market, hedge contract shortfalls may logically appear to be dominated by baseload Swaps – the most liquidly traded instrument in the NEM. Traditionally, large baseload thermal generators have been the predominant natural suppliers of Swap contracts. Indeed, regions where Swap contract volumes have reduced have exhibited statistically significant risk premiums (see Flottmann et al., 2024). However, when given the opportunity, VRE projects can sell on-market forward contract capacity including Swaps when combined with firming generation technologies such as gas generation or batteries (Flottmann et al., 2022; Simshauser, 2020). As our quantitative results have shown, any contract market shortfall can be reduced to varying degrees by ensuring VRE contract capacity is either on-market, or recycled, into forward markets.

We conducted an analysis of VRE market shares as a percentage of aggregate demand over different periods of the day. This included ‘Morning Peak’ (5am – 8:30am), ‘Solar Peak’ (8:30am – 4:30pm), ‘Evening Peak’ (4:30pm – 9pm) and ‘Overnight Period’ (9pm – 5am). Figure 7 illustrates that in each region, wind serves as the best proxy for Swap contracts as, on average, it may meet *at least* 30% of demand throughout the day. However, neither solar nor wind is particularly well suited to meet evening peak demand which has historically seen the most $300 Cap payouts, and therefore where Cap contract sales are most valuable.

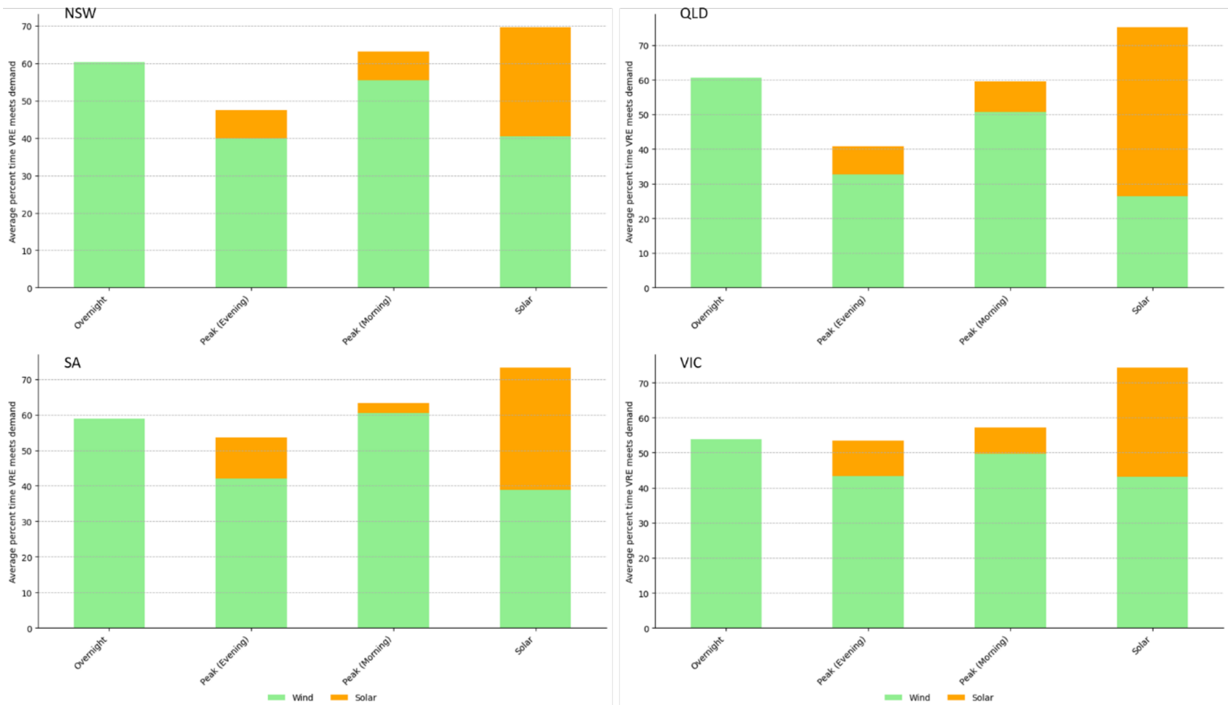


Figure 7: Average VRE market share as a percentage of demand over defined times of the day (Overnight, Evening Peak, Morning Peak, Solar)

When considering whether a $300 Cap contract shortfall may exist in the NEM, results are less clear. The impact depends on what dispatchable capacity replaces coal plant. To ensure our modelling was tractable and to provide a bookend result, our analysis used CCGT & OCGT plant capacity as the sole replacement for coal units. This provides a *‘best case outcome’* for primary issuance hedge contract capacity (cf. energy limited pumped hydro and batteries). The ability for pumped hydro & batteries to capture Cap payouts and therefore sell Cap contracts varies depending on their warranted duration.[9]

Ultimately, both Swap and $300 Cap contracts are likely to be in shortfall as coal plant exit the system. While coal exit implies Swap shortages, in Simshauser (2020) an OCGT plant was blended with wind

[9] In the case of gas generation such as CCGT & OCGT their ability to defend $300 Cap contracts would be significantly impacted by continuity of natural gas supplies (or other backup fuel sources) as Simshauser & Gilmore (2024) explain.

to provide baseload swaps – suggesting shortages in $300 Caps. The extent to which each contract type is in shortfall will be dependent on how plants are able to enter and participate in the market –

6. Policy implications and concluding remarks

The quantitative analysis presented in Sections 4-5 indicates if off-market, government-initiated fixed price CfD methods dominate VRE entry, significant shortfalls of primary-issuance hedge contract capacity is predictable. Conversely, our modelling suggested in all regions but SA, carefully designed CfDs where recycling is possible will all but eliminate such shortages.

Although considerable CfDs have been undertaken in NSW, Victoria and SA, shortfalls are yet to materialise in NSW and Victoria. The reason for this may vary but includes characteristics such as VRE plant entry being dominated by on-market transactions, coal plant exit being imperfect and lagging optimal exit, and/or mid-merit and peaking assets may currently be structurally oversupplied – thus providing a transient buffer to a shortage.

In other regions, viz. SA, structural shortages have been a slowly emerging issue which to date has not been adequately addressed. Importantly, if VRE is to enter through on-market PPAs or CfDs are recycled, adverse impacts to forward markets – their depth and liquidity – seem avoidable. The question for policymakers is whether on-market transactions can move at the same speed as policy intent, or what architecture a government requires to recycle CfDs back into the market.

Evidence from other jurisdictions usually suggests markets lag policy intent, or entry costs for certain high-cost technologies (e.g. offshore wind) require some level of policy priming through CfD-subsidisation. Either way, investment lag or high technology cost may well warrant government-initiated CfDs. But this research has highlighted that fixed price CfD activity is not compatible with contestable retail markets, without careful re-design. That is, the hedge contract capacity extracted by off-market fixed price CfD auctions needs to be recycled, or some other on-market policy mechanism (i.e. revenue collar) needs to prevail to ensure forward markets remain with adequate depth and liquidity. This is important with regards to the retail price of electricity.

This finding applies not only to VRE, but also to replacement dispatchable capacity. Indeed, careful design batteries, pumped-hydro or gas turbine CfDs is even more important. Such plant *must* be able to enter the contract market in such a way that allows firms to hedge a portfolio – which in turn is how intermittent run-of-plant PPA contracts become "usable" by energy retailers. In this sense, extracting firming capacity (i.e. batteries, pumped hydro, gas turbines) from forward markets makes things much worse than extracting VRE capacity, as it may render larger parts of the system *unhedgeable*.

There is anecdotal evidence that some projects in Australia's NEM, underwritten by government (revenue collar) CfDs, have forward-sold their plant output into the forward markets as on-market transactions – as was envisaged in the design of the Commonwealth's Capacity Investment Scheme CfD contracts. However, to the best of our knowledge, this has so far been fairly limited in scope and at least some risk exists that 'CIS' projects use the CfD revenue collar design as a floor on earnings rather than a platform for re-hedging. This is not to say CIS design has not or will not achieve its intended purpose – including recycling of plant in forward markets. If projects use the design as a floor instead of an option collar design, it may require a more nuanced approach to recycling CfD contracts in forward markets, such as the establishment of a government trading house.

In this article, we aimed to highlight whether structural shortages of hedge contract capacity may arise if projects choose not to participate in forward markets upon being awarded government-initiated fixed price CfD due to the risk of paying out twice during surging prices. Our substantive point is that the risk of shortfalls in hedge contract markets is plausible and likely and should therefore be a policy focus of government. Ultimately, failures in the forward markets are borne by consumers through a shrinking pool of energy retailers, higher hedge contract premiums, and all things being equal, higher electricity bills. A notable example is the SA region of Australia's NEM - premiums for contracts sold to predominantly retailers or large loads were extremely high as outlined in Flottmann et al. (2024).

Our analysis was designed to identify whether the forward market for contracts would adjust as large baseload coal generation plant exits at scale, with on-market PPAs and off-market fixed price CfDs. Results in our QLD scenario showed as coal plant exits due to uneconomic operation and increasing VRE deployment, the volume of hedge contract supply from base plant naturally declines. Importantly, to ensure enough generation is available to meet maximum demand significant quantities of mid-merit and peaking plant are required. The addition of this new plant adds to the supply of hedge contracts and helps to slow the loss of primary issuance hedge contract capacity. If VRE plant capacity enters by way of on-market PPAs, shortages at the margins may appear in some NEM regions – which suggests additional peaking capacity or alternate hedge contracts (e.g. weather derivatives) may be required.

Policy resolution seems to require one of two options. First, drive VRE plant entry by way of alternate market structures to facilitate on-market PPA entry (e.g. expansion of certificated Renewable Energy Targets, or write CfDs on the carbon component and leave the electrons exposed to the spot electricity market). Or second, establish a government trading house to facilitate secondary issuance, that is, the re-trading of CfD capacity acquired under auction and extracted from the NEM's forward markets. As renewable market shares continue to rise, one of these two options will ultimately be necessary to ensure the health of hedge market, and in turn, the retail market.

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