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On spot revenues, capital structure and trade off theory: Analysing investment risk for contracted renewables

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Abstract
In decarbonising power systems, shifting dynamics require that investors lend careful consideration when structuring plant revenues – or risk violating the constraints of private capital markets. In Australia's National Electricity Market, new variable renewable energy (VRE) plant was traditionally ~100% revenue contracted via power purchase agreement (PPA) to facilitate bankability and provide stable returns. However, sharply falling VRE costs have enabled the emergence of a new asset class, viz. VRE with 'semi-merchant' cashflows, comprising both PPA contracted and spot market (i.e. merchant) exposed revenue streams. This blended revenue mix, which has dominated new entry in Australia, raises questions vis-à-vis capital structure optimisation as both investors and financiers grapple with the re-introduction of spot revenue variability. In this paper, stochastic modelling techniques are applied to stress-test new entrant wind plant cashflows under a full spectrum of PPA cover levels and within capital market (i.e. project finance) constraints. Under ordinary market conditions, a run-of-plant PPA with >50% revenue cover is found sufficient to mitigate technical default risk and secure commercial debt levels. However, the relationship between PPA cover and default (i.e. distress cost) risk is also found to be decidedly non-linear, with some semi-merchant structures capable of supporting debt levels equivalent to 100% PPA plant without introducing material default risk – an unexpected finding. Presented results identify the limits of a PPA to extract equity capital risk from a stand-alone VRE asset and, by implication, the limits of cost of capital optimisation in line with Modigliani and Miller's seminal writings on capital structure.

Keywords: Renewable Energy, Cost of Capital, Project Finance, Hybrid Markets, PPAs.
JEL Codes: D53, G12, G17, G32, L94, Q40

1.0 Introduction

As global energy markets decarbonise, capital investment in new generation plant must be both sufficient *and* timely to replace existing thermal capacity. In Australia's National Electricity Market (NEM) end-of-life retirement of legacy coal baseload looms, with the dominant new entrant technology continuing to be a mix of variable renewable energy (VRE) (wind and solar) underpinned by requisite firming (storage and peaking gas) (Dodd & Nelson, 2019; Graham, 2024). An estimated AUD $285 billion[1] of invested capital is required for the buildout of replacement capacity alone (Simshauser & Gilmore, 2024). To put this task into perspective, the NEM's ~26 year history has absorbed a (comparably) modest c.$100 billion to fund new plant entry. Fortunately, capital markets now have a track-record of delivering timely capacity investment, provided adequate incentives are in place (Simshauser & Gilmore, 2020, 2024). Indeed, in Australia's

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[1] All dollar values reflect AUD unless otherwise specified.

deregulated energy markets, capital investment is predominantly a private sector responsibility.

The sheer size of the Australian investment task places ‘cost of capital’ as a critical hurdle to achieving decarbonisation targets. For any given plant, cost of capital is ultimately determined by capital structure - comprising the weighted proportions of debt and equity capital used to fund acquisition or construction. Equity investors are expected to ‘optimise’ a capital structure by leveraging comparably low-cost, tax deductable debt. In finance “trade-off theory” indicates equity investors will be motivated to raise debt up to the point where the marginal ‘cost of distress’ exceeds marginal gearing efficiencies (Kraus & Litzenberger, 1973; Myers, 1984).[2] However, under stand-alone project financing (PF), the ‘cost of distress’ to an equity investor is more nuanced – with proponents often seeking to simply maximise achievable borrowing due to the ‘non-recourse’ nature of the lending structure.[3] Any solution to the ‘capital structure puzzle’ for VRE must therefore begin with an analysis of *revenue quality*[4], so long as PF remains the dominant structure.

With VRE maturing – and indeed changing – as an asset class, investors have become increasingly familiar with the technology’s inherent risks, particularly those which diverge from traditional generation technologies viz. coal and gas. Operational *variability* is perhaps the most self-evident of these risks, with exogenous weather conditions driving intermittency for VRE production (Bublitz et al., 2019). Historically, Australian investors and project banks sought risk mitigation by signing long-dated ‘run-of-plant’ Power Purchase Agreements (PPAs) with investment grade (i.e. credit-worthy) counterparties to shield cashflows from spot price volatility and improve revenue quality (Finon & Pignon, 2008; Gilmore et al., 2023; Gohdes et al., 2022; Rai & Nelson, 2021; Simshauser & Gilmore, 2020). In the early days of VRE investment, new-entrant plant would typically secure financing on a ~100% PPA contracted basis – noting renewable entry costs greatly exceeded (expected) spot prices in equilibrium at the time. Securing 100% PPA cover effectively sleeves the ‘price’ component of generation revenues, guaranteeing the sale price for an initial 10-15 year period, typically escalating at the Consumer Price Index. These PPAs functioned well for generation investors (the PPA ‘seller’), as well as for energy retailers tasked with satisfying renewable energy targets or face penalties for non-compliance (the PPA ‘buyer’, or counterparty).

However, two forces combined to change this dynamic. First, the entry costs of VRE plant in Australia’s NEM plunged over the period 2000-2020 (see Simshauser and Gilmore (2020, 2022)), and ultimately fell below the running costs of marginal coal and gas-fired plants, making them economic in their own right – i.e. with no subsidy necessary. Second, the scale of renewable projects increased dramatically, as did the number of projects relative to buyers, causing PPA prices to fall accordingly. As numerous authors have observed, this led to an emergence of the ‘semi-merchant’ business model – with ~75% run-of-plant PPA cover and ~25% spot market exposure being the dominant format (Flottmann et al., 2024; Gohdes, 2023; Gohdes et al., 2023; Simshauser, 2021b; Simshauser & Gilmore, 2020).

[2] ‘Gearing’ referring to the proportion of debt capital within a capital structure, viz. $total\ debt\ /\ (total\ debt + total\ equity)$.
[3] Project finance structures make use of a stand-alone entity for the purpose plant ownership and operation, limiting creditor claims against the asset’s investors or parent company.
[4] Revenue quality, in this context, considers both volatility and reliability – with the highest ‘quality’ derived from investment-grade counterparties under long-term contractual agreements.

Compounding matters further, as renewable market shares increased, the frequency and intensity negative price events increased measurably in the NEM – particularly during mid-day periods where rooftop and utility scale solar produce instances of depressed demand and excess supply (McConnell et al., 2013; Simshauser & Wild, 2024). With run-of-plant agreements reflecting the NEM's dominant PPA structure, counterparties are generally protected from negative price events by incorporating a price 'floor' of $0.0/MWh to the floating leg of the contract. Zero-dollar price floors protect counterparties from negative price events by incentivising VRE to respond to spot market forces, ramping down during periods of excess supply and, ultimately, quarantining volume risk with the generator – including for assets which are 100% PPA contracted (Nelson et al., 2024).

With these issues as a backdrop, this investigation seeks to interrogate the historical practice of contracting VRE revenues via PPA in the context of capital structure optimisation. Optimal PPA cover levels are examined for a new entrant wind plant in Australia's NEM, applying market-standard PPA terms in the context of decarbonising energy markets. This analysis is particularly relevant as broader energy market 'hybridisation' (via government-initiated Contracts-for-Differences) becomes the policy tool of choice for Governments seeking to accelerate the entry of new renewable capacity (Gohdes et al., 2023; Joskow, 2022; Keppler et al., 2022; Roques & Finon, 2017).

The results of this paper carry implications for private investors seeking to maximise risk-adjusted returns, as well as for policymakers supporting new investment by relocating merchant exposure to the State's balance sheet. Analysis commences by levering an integrated, multi-year project financing model to produce a commercial-grade new-entrant investment benchmark for a variety of PPA contracted revenue levels in Australia's NEM. Once established, stochastic modelling techniques capture the variability of onshore wind generation, and stress-test the application of market-standard project financing covenants and equity return hurdles. Operational data from the South Australia (SA) region in Australia's NEM is applied – reflecting a market which has gone the furthest to decarbonise via utility-scale VRE plant (Mountain, 2025). 30-minute market data over a nine-year sample period is organised and randomised to produce 100 years of stochastic spot market prices and corresponding (i.e. time-stamped) coincident wind operations. The final dataset captures periods of overperformance and underperformance, allowing the model to stress test cashflows under a variety of market conditions.[5] Finally, an intra-year cashflow model is leveraged to capture variability in monthly revenue distributions and quantify the impact of distressed periods (i.e. instances of default) to capital providers.

By stress-testing plant cashflows at each level of PPA cover, from 100% (fully contracted) through to 0% (fully merchant), it is found that VRE assets with higher levels of PPA contract cover are, intuitively, capable of withstanding greater levels of spot price volatility than their merchant counterparts without triggering default events (i.e. incurring 'distress costs'). This in turn indicates the relationship between cashflow volatility and the frequency of financial distress continues to hold true for project financed VRE assets - consistent with trade-off theory detailed by Kraus and Litzenberger (1973) and Myers

[5] It is important to note that any method reliant on back-testing is not necessarily indicative of the future, instead offering insight on 'what is possible' based on observable history. Indeed, the SA region was selected to mitigate any risk of wind and spot pricing data being out of sample.

(1984). However, it is also found that the relationship between distress costs and PPA cover is decidedly *non-linear*, implying diminishing returns when PPA cover is maximised. Indeed, a semi-merchant structure with between 80-95% PPA cover appears capable of supporting *equivalent* debt levels to a 100% PPA structure without introducing material risk of technical default. In effect, the conceptual limit of a run-of-plant PPA's ability to optimise the cost of capital is identified, recoupling Myers' (1984) classic 'capital structure puzzle' to energy markets in transition.

As an adjacent finding, it is identified that VRE plant with less than 50% PPA cover will inherently experience a level of quarterly revenue volatility sufficient to challenge a typical PF structure – implying that balance sheet finance (also known as corporate financing) may be better suited.[6]

This paper is structured as follows. Section 2 provides a summary of relevant literature, Section 3 provides detail on the methodology and data, while Section 4 summarises model results. Policy implications and concluding remarks follow in Sections 5 and 6 respectively.

2.0 Literature Review

This analysis is concerned with Australian energy market dynamics, applicable capital structure theory and their interaction with project finance structures. Literature relevant to each of these areas is summarised as follows.

2.1 Decarbonising and Hybridising Energy Markets

Australia's NEM was formerly established in the late-1990s, during which a predominantly publicly owned, vertically integrated electricity supply chain was disaggregated and deregulated in an effort to enhance market efficiency via competition and privatisation (Simshauser, 2021a). Regulatory reforms split supply chains into three distinct operating categories, comprising generation, transmission, distribution (and retail supply), and established an energy-only, gross pool spot market as an interface (AEMC, 2024; Maddock & King, 1996). Privatisation necessitated a greater reliance on equity capital markets and new forms of debt capital to support new entrant capacity and address gaps in aggregate supply if and when they arise. Moreover, price volatility was a feature, not a defect, of the energy-only market design, facilitating real-time responsiveness of supply and producing merit-order effects vis-à-vis generator bidding behaviours (Antweiler & Muesgens, 2021; Billimoria et al., 2025; Littlechild, 1988). Australia's electricity markets are now known as one of the most volatile commodity markets in the world, with spot prices known to shift between the regulated price cap (currently $17,500/MWh) and floor (-$1,000/MWh) over remarkably short time horizons (Gilmore et al., 2023; McConnell et al., 2015; Nelson et al., 2024; Simshauser, 2010).

As is the case globally, the NEM's plant stock is rapidly transitioning towards zero and low carbon fleet (de Atholia et al., 2020; Dodd & Nelson, 2019; Nelson et al., 2022; Newbery, 2016; Pollitt & Anaya, 2016; Rai & Nelson, 2021). While investment in Australian VRE can be traced back as far back as the late-1990s, the market experienced an investment surge from 2016-2024 period, with 173 projects worth ~$54.8 billion and totalling 25.4GW of generation capacity (de Atholia et al., 2020; Simshauser, 2024; Simshauser & Gilmore, 2022, 2024). Investment behaviour over this

[6] Balance sheet finance (also referred to as corporate finance) reflects the more 'classic' approach to securing leverage in private markets, with new assets funded via debt raised and secured at a parent company level.

period is clearly distinct from the prior decade, with significant investment increases in large-scale VRE projects overwhelmingly driven by the private sector.

Increasing levels of VRE in energy-only markets guided by merit order effects introduces new risks and challenges (McConnell et al., 2013; Nelson et al., 2024; Sensfuß et al., 2008; Simshauser & Newbery, 2024). In particular, the variable nature of wind and solar generation creates challenges vis-à-vis matching inter- and intra-day supply with a notoriously stubborn aggregate final demand (Simshauser & Gohdes, 2024). Implementing VRE capacity at-scale requires supporting infrastructure to move electricity supply through both space (via network transmission) *and* through time (via short, intermediate and long-duration energy storage) (Newbery, 2018). The compounding risk of generation intermittency with spot price volatility has produced an environment whereby investment in new entrant VRE capacity requires some minimum level of PPA contracted revenues to support 'bankability' (Chao et al., 2008; de Atholia et al., 2020; Grubb & Newbery, 2018; Hundt et al., 2021; Kann, 2009; Newbery, 2017; Steffen, 2018).

Roques and Finon (2017), Grubb and Newbery (2018), Joskow (2022), Keppler et al. (2022), Batlle et al. (2022) and others observe that energy-only markets are approaching a new 'hybridised' regime, as policymakers re-enter liberalised markets to provide VRE projects with revenue underwriting support via long dated Contracts-for-Differences (CfDs). Many OECD countries appear to have identified state-backed revenue underwriting, often via CfD auction, as the least-cost solution to the problem of decarbonising energy markets while maintaining security of supply objectives (Newbery, 2017; Simshauser, 2019). Hybridised markets decouple long-term investment decisions from short-term market price signals and operations by acknowledging that long-term revenue agreements play a structural role in facilitating supply (Keppler et al., 2022). Likewise, competitive wholesale markets continue to promote cost-effective management of day-to-day operations for existing assets. The hybrid framework is intended to de-risk long-term capital-intensive investment decisions by mitigating the risks of short-term pricing fluctuations, theoretically making use of both centralised and de-centralised market elements (Keppler et al., 2022).

Both equity investors and project banks employ different treatments for cashflows depending on their anticipated volatility (Gohdes, 2023; Gohdes et al., 2022, 2023). Ceteris paribus, cashflows with elevated variability – viz. spot market revenues, will demand a higher return from equity investors, while debt financiers (i.e. project banks) will introduce more restrictive debt-sizing covenants. In other words, from a risk perspective, *not all revenues are created equal*.

Indeed, balancing the risk vs return trade-off between contracting asset cashflows via PPA or CfD (i.e. lower volatility) and exposing cashflows to the volatile 'merchant' spot and forward markets remains an ongoing subject of investigation (Rai & Nelson, 2021; Simshauser & Gilmore, 2020). As outlined in Section 1, in Australia's NEM, falling renewable entry costs, relatively low PPA strike prices, and relatively high spot electricity prices have combined to create an environment where "semi-merchant" assets emerged as a preferred structure for many investors – i.e. assets with cashflows which are predominantly PPA contracted while retaining partial spot market exposure (Gohdes, 2023; Gohdes et al., 2023; Rai & Nelson, 2021; Simshauser & Gilmore, 2020). As an aside, VRE plant curtailment risk is *not* typically hedged under run-of-plant PPAs, meaning spot price exposure is never completely eliminated from the asset – a fact which forms a key part of this investigation.

2.2 Capital Structure and Project Finance

As is the case with virtually all infrastructure, the global energy sector is appropriately characterised as *capital-intensive*. Indeed, the 'cost of capital' reflects a fundamental investment hurdle to the development of new entrant capacity (Gohdes et al., 2022; Simshauser & Gilmore, 2020). A commercial cost of capital is ultimately determined by the required return of the market's two sources of capital – debt (bank finance or debt capital markets) and equity (retail and institutional investors) and, importantly, the *weighted proportions* thereof (Myers, 1984). Identifying viable solutions to the 'capital structure puzzle', as coined by Myers (1984), becomes paramount for investable new entrant capacity. The 'puzzle' which this analysis is focused on concerns optimisation – i.e. through what means can investors secure a commercial cost of capital for new entrant plant under the real-world constraints imposed by capital markets?

Myers' capital structure puzzle may appear solved c.25 years prior in Modigliani and Miller's (1958) seminal work on the cost of capital (known as 'MM'). Indeed, MM provide formal proof that the cost of capital of a firm *cannot* be reduced via structural alteration (proposition I) and, importantly, that a firm's cost of equity will increase and absorb efficiencies brought about by elevated gearing levels (proposition II), assuming perfect markets. However, we know investor equity return expectations tend to be 'sticky' in the face of increasing leverage (Gohdes et al., 2022; Simshauser, 2014; Simshauser & Ariyaratnam, 2014). While a comprehensive explanation for this phenomenon is beyond the scope of this paper, the following two observations are made:

1. Gohdes et al. (2022) identifies the VRE cost of capital can be materially reduced by repackaging and reallocating risk via increased 'revenue quality' – i.e. contracting via a run-of-plant PPA, an observation supported by other works (NAB, 2020; Rai & Nelson, 2021).
2. MM's formal proof makes the fundamental assumption that firm revenues are exogenously determined. This assumption does not hold in electricity markets, with contracted PPA strike prices and long-run market prices ultimately converging on the cost of new entrant capacity, of which the cost of capital constitutes a key component (Simshauser & Gilmore, 2020).

Both observations affirm conditions whereby cost of capital for stand-alone plant can be materially reduced - namely, when assets exhibit high *revenue quality* (with the risk being absorbed by some other counterparty in exchange for a lower PPA strike price).

To generalise the literature, capital heavy infrastructure, including supply-side electricity generation assets, have two options when raising debt – viz. project finance (off-balance sheet) or financing 'on balance sheet' (Esty, 2004; Rai & Nelson, 2021; Simshauser & Gilmore, 2020; Steffen, 2018). Given the prevailing preference for high gearing levels among VRE investors (typically ~65-80%), PF persists as the dominant financing structure (Kann, 2009; Steffen, 2018). PF deploys a legally independent project company – i.e. a 'special purpose vehicle' (SPV), for the sole purpose of asset ownership and management. The structure is capable of producing highly geared capital assets with precise risk allocation, transparent information flow and fixed management protocols (Esty, 2003; Esty, 2004). As a result, consideration of Myers' 'capital structure puzzle' becomes concerned with optimisations within the SPV, rather than at the parent company level.

Left-hand tail risk to asset cashflows, brought about by plant underperformance, revenue shortfalls or broader market conditions, are quarantined within the SPV via PF's non-recourse structure. Indeed, PF mitigates creditor claims on parent company assets - including the claims of project bank lenders. In turn, project banks must gain comfort with an asset's financial viability on a stand-alone basis via rigid cashflow management protocols and imposing strict 'covenants' to monitor the SPV's financial health (Borgonovo & Gatti, 2013). Extended periods of sub-optimal profitability risk falling outside the bounds of these rigid protocols. Leverage is hence typically limited by the level, volatility and expected *quality* of asset revenues – traditionally derived from fixed-price PPA contracted cashflows (Gohdes et al., 2022). Indeed, minimising revenue volatility remains necessary to support the stable quarterly cashflows required for asset bankability (Grubb & Newbery, 2018; Hundt et al., 2021; Kann, 2009; Mills & Taylor, 1994; Newbery, 2017; Steffen, 2018).

Analysing capital assets under PF structures has the benefit of eliminating vagaries of historical profitability and strategic commitments otherwise present for established firms (Esty, 2004). Given the life of the SPV is typically restricted to the useful life of the underlying VRE asset, other considerations vis-à-vis capital structure can also be reasonably dispensed, allowing for a more direct application of a 'static' trade-off theory as detailed by Myers (1984) (cf. the 'pecking order theory' of Myers and Majluf (1984) – see also Kraus and Litzenberger (1973)). A static capital structure trade-off implies that an SPV balances the marginal decision of securing additional leverage against the marginal cashflow advantages (viz. taxation shields[7]) and marginal cashflow disadvantages (viz. financial distress costs) (Kraus & Litzenberger, 1973; Modigliani & Miller, 1963; Myers, 1977, 1984). Under this simplified frame, a stand-alone asset under PF pursues maximum serviceable leverage, limited only by the emerging risk of financial distress under excessive gearing. Doing so reduces the SPV's effective weighted average cost of capital via capital structure 'optimisation'. Regarding financial distress risk, the non-recourse nature of PF limits equity investor losses to ex-ante SPV distributions (Esty, 2002). Quantifying 'distress cost' exposure to equity investors under a PF therefore requires nuanced consideration, for which there is limited precedent in the literature.

Borgonovo and Gatti (2013) outline a useful conceptual framework when quantifying the financial impact of default to equity investors, distinguishing both 'technical' and 'material' covenant breaches for project financed assets.[8] It is critical to note that covenant breaches will not be assumed in an equity investment case, ex-ante. However, it is known from real-world observation that investors *can and do* lose money under sufficiently poor market conditions, ex-post. An analysis of PF covenants provides guidance vis-à-vis distress cost quantification - an exercise which is necessary given financial distress acts as a counterweight to gearing efficiencies when optimising cost of capital (Kraus & Litzenberger, 1973).

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[7] Cashflow advantages via interest tax shield recognise that interest payments are tax deductible, while equity distributions are not.

[8] Borgonovo and Gatti (2013) quantify the impact of a PF covenant break to equity cashflows as comprising; a) delayed distributions in the case of a 'technical breach' due to enforced cash sweeps to pay down debt; and b) a loss of all future distributions in the case of a 'material breach', with the pledged shares of the SPV falling into the hands of lenders.

3.0 Data and Methodology

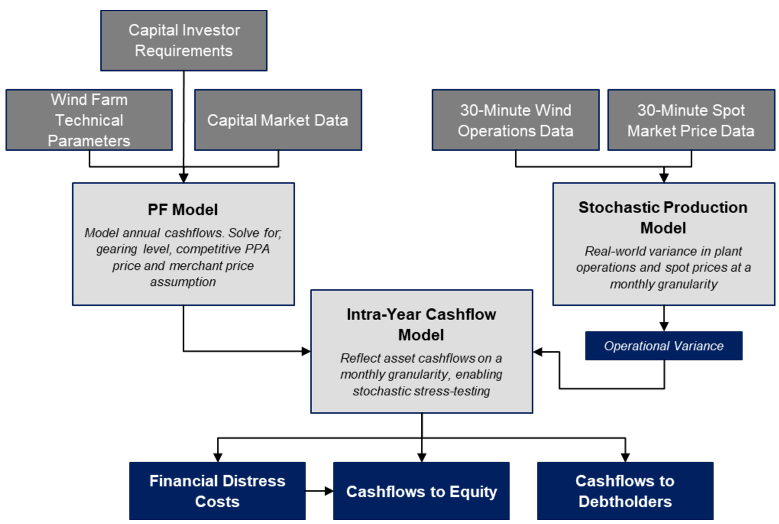
This modelling exercise comprises three district modules – viz. a project finance model (PF Model) at annual granularity, a stochastic production model at 30-minute granularity and an intra-year cashflow management model at monthly granularity. Model outputs are cointegrated to produce final results detailed in Section 4.

3.1 Data and Assumptions

As a general comment, data and assumptions predominantly rely on publicly available and accessible information from Australia's energy markets. Plant performance data applied to the stochastic production model (Section 3.2) comprises historical 30-minute spot market price data from the Australian Energy Market Operator (AEMO).

Models simulate the performance of a hypothetical 1000MW new-entrant wind farm asset located in South Australia.[9] Plant operations are established over the asset's full useful life, tasking the PF Model to dynamically solve for revenues and debt size under a range of semi-merchant structures (i.e. various blends of PPA cover and spot market exposure). Simulated plant operations from the PF Model, along with the outputs from the stochastic production model, are used to inform the intra-year cashflow model - stress-testing via a PF cashflow waterfall. Figure 1 depicts the integration of data sources and the three models, along with critical outputs.

Figure 1: Integration of Modelling



3.1.1 Plant Technical Parameters

Operational and technical parameters are aligned with 2023-2024 annual GenCost report prepared by Commonwealth Scientific and Industrial Research Organisation (CSIRO) in collaboration with AEMO.[10] Technical inputs include generation capacity, capital cost, operational costs and maintenance costs. Annual capacity factor is reflected net of transmission and auxiliary losses and is aligned with the average capacity factor observed for wind plant in South Australia during the 2016 – 2024 sample period (being

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[9] South Australia has been selected as the state which has made the most progress towards grid decarbonization. At the time of writing, the state supplies more than 70% of electricity demand from renewable sources, while regularly experience periods renewable penetration above 100%; https://reneweconomy.com.au/south-australia-sets-spectacular-new-records-for-wind-solar-and-negative-demand/

[10] https://www.csiro.au/en/news/all/news/2024/may/csiro-releases-2023-24-gencost-report

33%). Inflation is aligned with the mid-point of the Reserve Bank of Australia's (RBA) target range (2.0 - 3.0%) and taxation is set at the Australian corporate tax rate.

Table 1: Technical and Macro Economic Inputs

New-Entrant Wind Farm		Input
Technical Parameters		
- Project Capacity	(MW)	1,000
- Overnight Capital Cost	($/kW)	3,038
- Annual Capacity Factor*	(%)	33.0%
- Auxillary Load	(%)	1.0%
- Transmission Losses	(MLF)	1.000
- Fixed O&M	($/MW/a)	25,000
- Variable O&M	($/MWh)	0.00
- Ancillary Services Costs	(% Rev)	-1.0%
- Useful Asset Life	(Yrs)	30
Macro Assumptions & Taxation		
- Inflation (CPI)	(%)	2.5%
- Corporate Tax Rate	(%)	30.0%
- Taxation Useful Life	(Yrs)	30

*Aligned with average annual capacity factors observed for wind plant in South Australia between 2016 - 2024

3.1.2 Semi-Merchant Asset Structure

Table 2 details assumptions pertaining to project finance, gearing and expected equity returns. Input variables which diverge for spot revenues vs. PPA revenues are pro-rated based on PPA cover ratios to produce a 'semi-merchant' input assumption. By way of an example, a wind farm with 75% of revenue contracted via a run-of-plant PPA will require a 9.0% equity return hurdle, calculated as: $8.0\% \times 75\% + 12.0\% \times 25\% = 9.0\%$.

Table 2: Capital Market Inputs

Wind Farm Project Finance		Merchant	Contracted
Debt Sizing Constraints			
- DSCR*	(times)	2.40	1.35
- Gearing Limit	(%)	50.0	80.0
- Lockup	(times)	1.15	1.15
Project Finance Facility - Tenor			
- Facility A Tenor	(Yrs)	7	
- Refi Frequency	(Yrs)	7	
- Notional amortisation	(Yrs)	25	
Project Finance Facility - Pricing			
- Facility A Swap	(%)	4.79%	
- Facility A Spread	(bps)	260	180
- Facility B (Refi) Swap	(%)	4.34%	
- Facility B (Refi) Spread	(bps)	260	180
- Refinancing Fee	(bps)	100	
Expected Equity Returns (Ke)	(%)	12.0%	8.0%

*DSCR refers to the debt service coverage ratio applied by project banks when sculpting debt size and amortisation profiles

While a *maximum* limit on asset gearing is imposed, the final debt size and amortisation profile is sculpted via the Debt Service Coverage Ratio (DSCR - a well-known PF measure of net free cash relative to debt repayments) within the model. This mechanism allows the PF Model to dynamically size debt based on the quality of asset revenues (i.e. PPA vs spot exposed), aligning with the typical approach adopted by international project banks in the Australian market.[11]

3.1.3 Contracted Revenue Terms

While the proportion of PPA revenue cover is flexed across each 'investment case', underlying terms are held constant (i.e. the strike price does not move in-line with changes in the revenue mix to avoid false results).

All applied PPA structures follow NEM convention, i.e. they impose an obligation to sell the full proportion (%) of contracted generation which the plant is capable of producing to the counterparty with an exception carved out during periods where the reference spot price is negative. At all times, PPA contracted generation is simply defined as; $generated\ MWh \times \%\ PPA\ cover = contracted\ MWh$. For the avoidance of doubt, modelled PPAs presume a BBB rated private counterparty.

If the reference spot price is negative during a given 30-minute interval, economic incentives will direct a ramping down of plant operations.[12] This practice quarantines generation volume risk during negative price events with the generating asset. Volume risk therefore cannot be entirely hedged away, leaving capital exposed if negative price

[11] In recent years, additional gearing restrictions have been imposed by project banks seeking to apply greater conservatism to merchant exposed assets. These have included 'break-even' merchant pricing constraints, which ensure that stand-alone assets can meet minimum financing obligations under persistently low spot prices - see Gohdes (2023). As break-even pricing levels can vary materially between lenders, asset classes and regions, a higher-than-average DSCR of 2.40x is imposed on merchant cashflows to reflect this conservatism.

[12] "Reference spot price" for a PPA typically includes a bundled price for generation as well as green certificates.

periods rise in intensity and frequency (Nelson et al., 2024). In this sense, a PPA *is not* synonymous with a guaranteed revenue stream, a fact which is evident in later results.

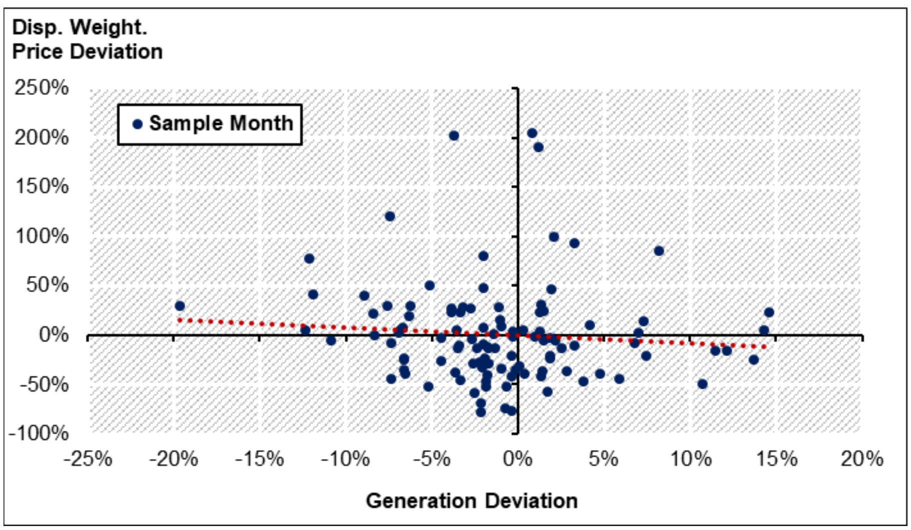
3.2 The Stochastic Production Model

The stochastic production model is tasked with inputting real-world energy market and wind performance data to produce a set of monthly *deviations* from the mean spot dispatch weighted energy price and plant production assumption.

Nine years of 30-minute time-matched South Australian wind performance data (2016 – 2024) and price data has been compiled. In each 30-minute period, the collective production of all wind assets in the region is observed, alongside the corresponding spot price of electricity. The total nameplate wind plant capacity is derived, reflected in megawatts (MW), for each 30-minute period to calculate the region's implied wind capacity factor. Model logic is set out in Appendix I.

At this point, it is critical to observe one key characteristic of the resulting dataset, being the *inverse* relationship between dispatch weighted prices and generation output. That is, as wind output rises, spot prices fall. Figure 2 depicts this relationship.

Figure 2: Stochastic Data, Generation vs Dispatch Weighted Price



While Figure 2 does indicate the relationship is not necessarily statistically strong (as evidenced by numerous material outlier samples), a relationship is present – as indicated by the trendline.[13]

The consequence of the inverse relationship between sampled generation and dispatch weighted price is as follows; in the aggregate, periods of *lower supply* are on average offset in part by *higher dispatch weighted prices*. Importantly, each month in a given stochastic year carries a specific production deviation ΔM_m (per equation A.3) and a

[13] It is noted that electricity demand is not shown in Figure 2, as it is not directly relevant to this analysis. For completeness, the author notes prevailing spot prices are ultimately a function supply (i.e. generation, per the x-axis) *and* electricity demand.

price deviation ΔP_m (per equation A.6), which remain paired to ensure the relationship between market pricing and wind production, depicted in Figure 2, remains intact.

3.3 The PF Model

The PF Model is an integrated, multi-year, dynamic power project finance and investment model tasked simulating typical Australian generation asset parameters while restricted by requirements of the two dominant capital providers, viz. project banks and institutional equity. Model logic is set out in Appendix II.

To summarise, the PF Model is tasked with identifying the lowest possible electricity price (P) at time $t = 1$ *while* ensuring equity returns (ke) are no less than those required under PPA cover level C. Solving for $P_{t=1}$ is hence synonymous with solving for the PPA price and dispatch weighted spot price assumption (PPA and $spot$) by specifying $C = 1$ and $C = 0$ respectively – providing an estimate of the minimum *competitive* PPA price and the minimum *viable* spot price assumption for the asset, while simultaneously considering plant operations, taxation and capital structure.

For the avoidance of doubt, the PF Model is capable of producing debt sizing and dividend outputs for each value C, where $0 \leq C \leq 1$. The value of C impacts four key formula, comprising asset revenues (A.11), debt sizing covenants (A.20), interest rates (A.27) and equity returns (A.29). The degree to which C is <1 determines the degree to which the asset is exposed to spot prices when producing revenues. The closer C is to zero, the higher the asset's equity return hurdle, interest rates and financing covenants (leading to lower levels of debt in the capital structure). Put simply, greater spot exposure results in a higher cost of capital when input variables are applied mechanistically.

3.4 The Intra-Year Cashflow Model

While the PF Model establishes detailed annual cashflows and operation outputs over the useful asset life, modelling intra-year cashflow volatility (i.e. at a monthly and quarterly resolution) is required when determining if financing covenants have been met. To this end, a more granular *monthly* cashflow model is employed, designed to reflect a typical 'cashflow waterfall' for VRE assets operating under a PF structure. The granularity of this approach allows integration of stochastic outputs ΔM_m (per A.3) and ΔP_m (per A.6) for the purpose of "stress testing" various revenue contracting levels. In essence, the intra-year cashflow model assesses the ability for the asset to meet financial obligations during each stochastic 12-month sample. Model logic is set out in Appendix III.

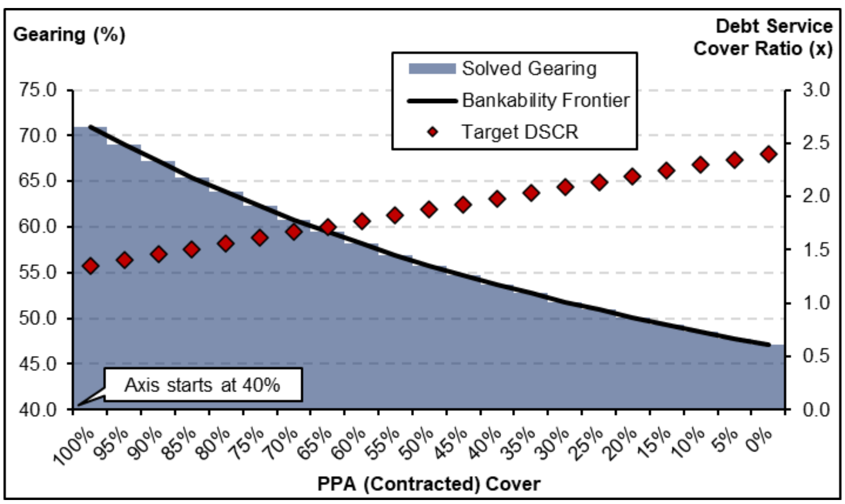
4.0 Results

The modelling sequence commences with the PF Model, which is run to produce commercial-grade new entrant cost estimates for each level of PPA revenue cover. Each estimate reflects an 'investment case' for the respective contracting level, co-optimising and solving plant revenues, gearing levels and the appropriate cost of capital given the revenue structure. Once cashflows are estimated by the PF Model, each investment case is stress-tested in the intra-year cashflow model against 100-years of stochastic plant performance data. This tests the performance of each level of PPA revenue cover (i.e. each investment case) observed in practice against PF bank covenants to identify which cases *manifest distress*.

4.1 Investment Cases

The PF Model is run according to plant specifications detailed in Table 1, while bound by hurdle rates and the PF covenants required by equity investors and debt capital providers (set out in Table 2). A simulation is run for each level of PPA revenue cover (100% to 0%) to produce a unique revenue outcome and, consequentially, a unique capital structure bound by the various limitations. Recall from Section 3.3 that the level of PPA cover (C) will impact an asset's revenue quality, debt sizing covenants, cost of debt and cost of equity. Figure 3 depicts the relationship between PPA revenue cover and commercially achievable capital structure, referred to here as the 'bankability frontier' for new entrant wind. In each instance, the viable level of gearing within the capital structure is determined by the debt service coverage ratio imposed by project banks, plotted on a secondary vertical axis. Gearing ranges between c.71.0% for a fully PPA contracted asset and 47.1% for a fully merchant asset. Note, these outputs are *not* a commentary on the ultimate viability of gearing levels imposed by project banks. Rather, they are simply a function of a mechanistic application of typical gearing constraints for wind assets in Australia's NEM.

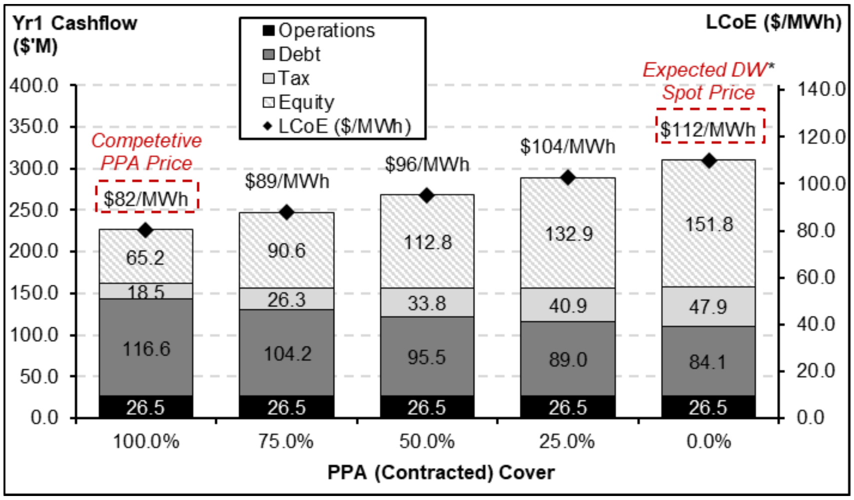
Figure 3: Bankability Frontier for New Entrant Wind[14]



Capital structure and asset cashflows are, of course, intrinsically linked. Achievable gearing is limited by the quantum and quality of asset cashflows, while equity distributions are subordinate to debt servicing in the cashflow waterfall. The PF Model is hence tasked with identifying minimum required revenues to simultaneously meet equity return hurdles *and* meet SPV debt covenants in order to achieve viable gearing levels. The entry cost for five (5) discrete investment cases are depicted in Figure 4 in $/MWh, along with proportional cashflow allocations in year one.

[14] Gearing levels remain broadly aligned with the survey results of Gohdes et al. (2022)

Figure 4 – Investment Case Cashflows and New-Entrant Cost[15]



* DW refers to 'dispatch weighted' spot price for wind

Key observations regarding Figure 4 include the following:

1. The cost of plant operations (see black stacked column) *does not change* across investment cases, as input modifications are limited only to plant revenues and the resulting capital structure of the asset.
2. As PPA cover decreases, the absolute cost of debt (in dollar terms) decreases in line with gearing, with debt necessarily replaced by higher cost equity (per Figure 3).
3. Decreasing PPA cover increases the asset's total cost stack as; a) the minimum equity return hurdle (the cost of equity) is higher than interest charged by project banks (the cost of debt) on a post-tax basis and, b) the absolute cost of both debt *and* equity increase as the asset is exposed to higher levels of spot pricing risk, raising the asset's cost of capital.

Figure 4 overlays levelised cost of electricity (LCoE) for each investment case, which is calculated as the asset's total long-run cost divided by total generation in MWh. By implication, this calculation aligns with the minimum average price at which generation must be sold to meet all financial obligations and make a satisfactory return on capital. For the purpose of this analysis, the calculated new entrant LCoE is synonymous with:

a. The *competitive* bid for a run-off plant PPA, at $81.7/MWh, and
b. The average dispatch weighted spot price expectation for an incoming equity investor targeting a 12.0% return on spot revenues, at $111.8/MWh.

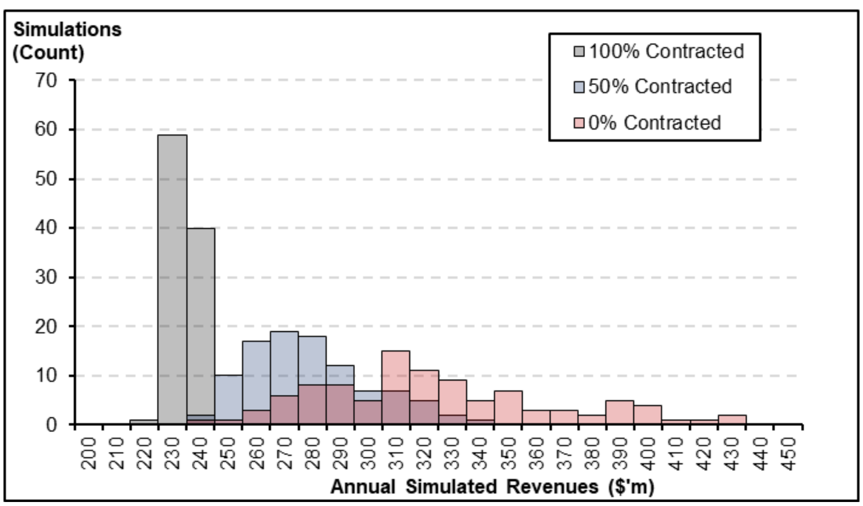
For the fully merchant (0% PPA contracted) case, a higher total quantum of revenues must be anticipated to meet required returns. This is necessary to offset a lower interest tax shield and higher cost of capital due to elevated anticipated cashflow volatility (i.e.

[15] Figure 4 depicts only five investment cases for simplicity and legibility, while twenty-one discrete cases are modelled using the PF Model (0% through to 100% contracted).

spot revenues are markedly more volatile than a fixed price PPA).[16] The 26.9% LCoE delta between the wind farm with 100% PPA cover, and the merchant wind farm selling at the spot price (viz. $81.7 vs $111.8/MWh) reflects the discount received by the PPA's counterparty as compensation for underwriting spot market price risk. It is key to note that higher levels of gearing (c.71.0% per Figure 3) are indeed *required* to support a competitive PPA price. Merchant gearing levels (c.47.1%) do not provide a sufficient tax shield, nor sufficiently minimise equity capital contributions to facilitate a competitive strike price discount vs spot market forecasts. Hence, under the pressure of competitive market forces, VRE bankability and PPA cover become linked – i.e. highly contracted assets require high gearing to lower equity contributions and meet return requirements. By implication, much of the financial upside provided by higher gearing levels is effectively handed back to the PPA counterparty in the form of a discount to the price of electricity. In exchange, an equity investor enjoys revenues, and indeed returns, which are less volatile.

Finally, stochastic revenue variability is introduced for each investment case via the intra-year cashflow model. PF Model and stochastic production model outputs are simultaneously applied in line with the methodology described in Section 3. Altering monthly plant revenues via ΔM_m (generation deviation) and ΔP_m (spot price deviation) produces a range of simulated results, depicted in Figure 5 via a histogram. A review of Figure 5 reveals the significant (and predictable) increase in revenue volatility associated with spot market exposure. While *average* revenues increase by a modest 38.2% between 100% and 0% PPA contracted cases, from c.$225.0m p.a. to $310.8m p.a., standard deviation increases *materially* from $3.1m to $41.3m - a 1,220% increase.

Figure 5: Stochastic Revenue Outputs – Histogram[17]



In reviewing Figure 5, it is important to note the *average* generation and spot price deviations (ΔM_m and ΔP_m) remain ~zero, i.e. $0 \approx \frac{1}{100} \cdot \sum_{i=1}^{100} \Delta M^i \approx \frac{1}{100} \cdot \sum_{i=1}^{100} \Delta P^i$, recalling the stochastic production model calculates each price and production deviation against

[16] It is noted that while Figure 4 may appear to violate MM prima facie (i.e. highest cost of equity existing under the lowest gearing conditions), it is critical to note that that the asset's revenue profile (and risk profile) has been fundamentally altered as PPA cover is decreased. A merchant asset carries a higher *and* more volatile expected revenue, conducive to lower gearing levels and higher equity returns.

[17] Figure 5 depicts only three investment cases for simplicity and legibility, showing 100%, 50% and 0% PPA cover.

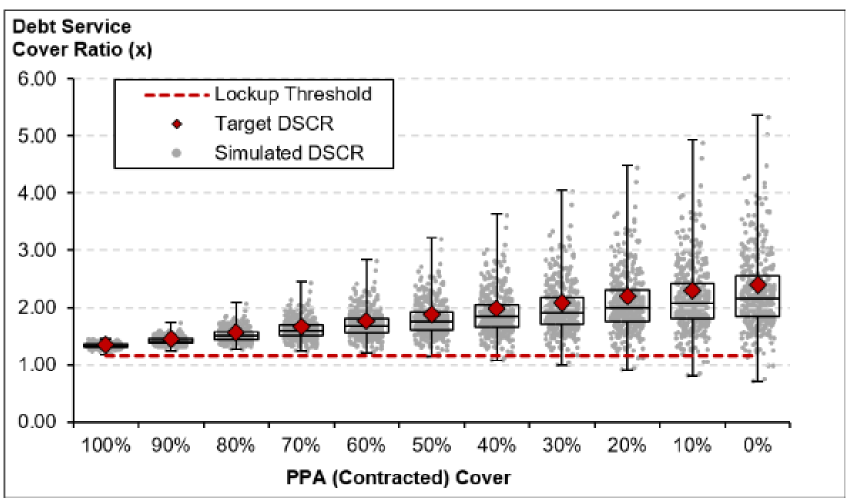
the relevant mean. This is critical, as revenue volatility does not impair the average returns of a merchant asset, provided no penalties are levied during periods of poor performance. This assumption will be relaxed in subsequent analysis.

4.2 Introducing PF Covenants and Technical Breaches

The analysis progresses by introducing covenants applicable under a typical PF structure. In doing so, the viability of each investment case is re-assessed and distress costs[18] associated with excess leverage can be estimated. The focus begins on 'technical breaches', which constitute short-term, transitory, covenant breaches insufficient to trigger bankruptcy. Technical breach penalties typically involve a dividend 'lockup' and an accelerated repayment of the outstanding debt balance via a 'cash sweep'. As described in Section 2, project banks monitor SPV cashflows via the debt service coverage ratio (DSCR), calculated as the ratio of free cashflow to debt service commitments during a given repayment period (typically quarterly). The threshold to trigger a technical breach lockup is set at 1.15x DSCR, per Table 2.

Stochastic revenue outputs discussed in Section 4.1 are relied upon to produce an equivalent set of DSCR simulations for each investment case. 100 years of stochastic performance is simulated, each with four quarters of DSCR checks. Figure 6 plots the distribution of simulated DSCR checks via a boxplot. The outputs found in Fig.6 reinforce the notion that the volatility of spot market revenue exposure materially impacts cashflow variance, with 0% PPA contracted simulations experiencing a DSCR standard deviation approximately 17.1 times *higher* than 100% PPA contracted simulations.

Figure 6: DSCR Checks from Stochastic Simulations

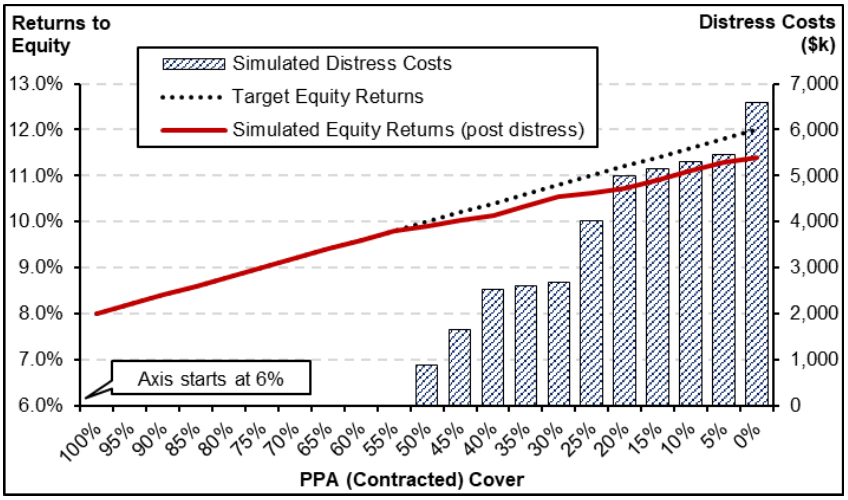


The most crucial result from Figure 6 is the total number of simulations where DSCR checks fall below the 1.15x lockup threshold. Despite registering lower DSCRs on average, no technical defaults are simulated for investment cases with at least 50% PPA cover. Below the 50% threshold, defaults are not necessarily commonplace, however they do occur reliably in 2-5% of simulations. These results speak directly to the bankability of predominantly merchant VRE plant under a PF structure. Assuming a ~25-year notional financing tenor, results imply that defaults are expected in at least 1 of 25

[18] Here 'distress costs' are once again referred to in the classic sense, referring to the body of literature analyzing capital structure and associated trade-off theory.

years without any exogenous cashflow shocks. In other words, merchant plant should anticipate technical default within the *ordinary course of business,*[19] with results only worsening if exogenous distress manifests.[20] Distress costs are quantified in Figure 7, with implications for equity returns overlayed.

Figure 7: Average Simulated Distress Costs[21]



At this point it is key to note that dividend lockups and cashflow sweeps do not form part of an equity investor's base investment case. A prudent investor will model a level of cashflow volatility as part of a comprehensive due diligence process. However, this analysis goes beyond the volatility of equity returns. Model results indicate that assets with sufficiently volatile revenues may routinely violate quarterly financing covenants, making the investment case implausible. By implication, VRE with below 50% PPA cover may be better supported by the relative flexibility of a balance sheet financing structure when securing debt capital.

Returning to the investment cases which are permanently PPA contracted (i.e. 50-100% PPA cover), debt sizing limitations of between 1.35x – 1.82x DSCR appears to eliminate technical default risk during ordinary business operations. That this, the cashflow buffer provided by these DSCR set points, combined with the relative stability of PPA revenues (at 50% cover or greater) drives the outcome. Interestingly, many semi-merchant cases (i.e. with spot exposure no greater than 45%) appear *no more likely* to experience technical default than an investment case with 100% PPA cover case – implying there may be scope for higher gearing levels for semi-merchant assets without introducing excess technical default risk.

To better test this observation, the subsequent line of enquiry seeks to identify the maximum gearing level supported by each investment case before risking technical

[19] Commercial solutions to mitigate lockup risk can and do exist for investors, including, but not limited to maintaining strategically sized minimum cash balances, withholding windfall distributions or maintaining term deposits. Each of these options will reduce investor returns to varying degrees, meaning their detailed analysis may represent a topic for further investigation, provided maximising merchant exposure is an objective.

[20] Exogenous distress may take various forms for VRE plant, including grid connectivity issues, prolonged renewable drought and unfavourable market conditions not considered ex-ante. Gohdes et al. (2023) and Gohdes (2023) detail additional scenarios of exogenous distress when testing fully contracted and semi-merchant assets.

[21] Distress costs are depicted as an average across 100 stochastic simulations. Swept cash during individual simulations averages $99.6m, but can range as high as $146.7m in a single year.

default under base-case plant operations. Each case is re-simulated while gradually relaxing the applied DSCR debt sizing parameters. Figure 8 displays results by depicting stochastic technical default outcomes under progressively relaxed debt sizing parameters. To be clear, decreasing the DSCR applied when sizing debt increases the gearing of an asset, holding ex-ante cashflows constant. The extent to which gearing shifts in each iteration is shown in Figure 9. When interpreting both Figure 8 and Figure 9, it is critical to note the following:

1. All cases experience technical default once DSCR is reduced by 0.20x, with highly PPA contracted assets most affected by proximity to the 1.15x lockup covenant (recall that 100% PPA contracted cases commence with a 1.35x DSCR target for debt sizing, meaning defaults are expected once the target is reduced by 0.20x).
2. The cases which are slowest to default, and hence have the greatest capacity for higher gearing, are those with a PPA revenue range between 70-85%.
3. Final results are depicted in Figure 9 via the ‘gearing frontier’, which shows the *maximum* level of gearing supported by each investment case without elevating risk of technical default.

Figure 8: Technical Default with Elevated Gearing

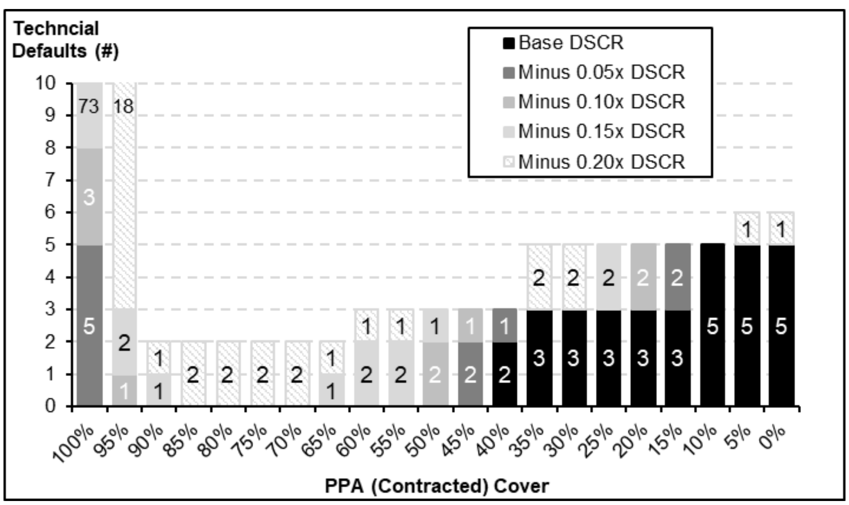
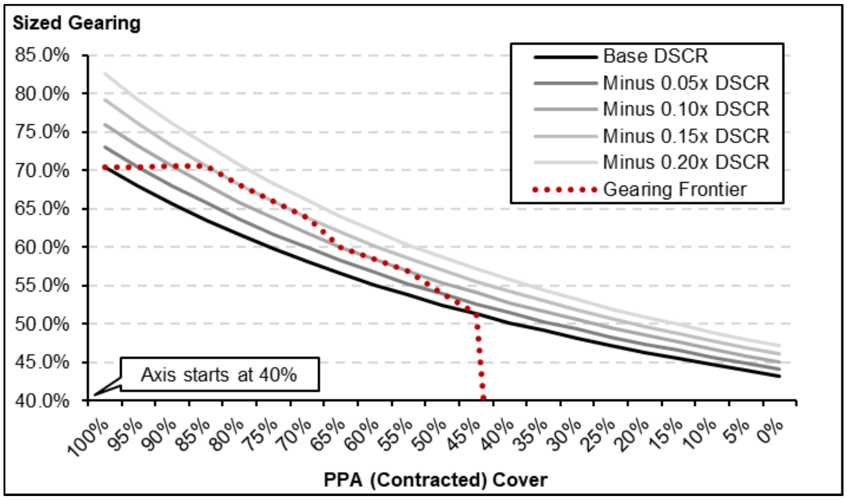


Figure 9: Viable Gearing Frontier



Interestingly, as gearing constraints are relaxed, the 100% PPA (fully contracted) case registers more technical defaults than semi-merchant cases – experiencing default immediately when DSCR is relaxed below 1.35x. The 100% PPA structure appears to have reached an effective "ceiling" of leverage at ~71% gearing, beyond which technical defaults materialise in the ordinary course of business – at least based on current Australian wind costs, costs of capital and market prices.

One implication of these results is a semi-merchant structure with 80-95% PPA cover appears viable with the same quantum of equity capital (supported by the same level of gearing) as the 100% PPA structure, without introducing materially higher risk of technical default. This was an unexpected finding.

Securing a semi-merchant revenue profile with the equivalent debt of a 100% PPA would allow an equity investor to capture higher asset returns via elevated spot market exposure without and change to the risk of default.[22] Indeed, further optimisation vis-à-vis debt size appears to exist for each semi-merchant structure to some extent, with the final 'gearing frontier' being decidedly non-linear (i.e. diminishing returns present above a ~80% PPA cover). These results carry an additional implication - that a traditional run-of-plant PPA has identifiable limits vis-à-vis equity risk mitigation and, by extension, capital cost optimisation. Indeed, ~71% gearing appears to be the point at which cost of capital *cannot be further optimised*.

To be clear, extending gearing above a ~71% threshold tips the asset into an elevated risk of default, even under cases where revenues are 100% PPA covered. Leverage above this level should carry a commensurable increase in the return expectation of equity investors as compensation for introducing material default risk. Any incremental capital cost optimisation produced by introducing additional lower-cost debt in the capital

[22] Whether project banks would support this capital structure is a separate question and is, unfortunately, beyond the scope of this analysis.

structure would therefore be eliminated. In essence, the conceptual limit of a traditional PPA's ability to optimise VRE cost of capital has been identified.[23]

4.3 Material Breaches

The final stage of this analysis considers asset performance outside the ordinary course of business – viz. instances of material default and bankruptcy. Original mechanistic gearing levels for each investment case are re-applied (per Figure 3), and SPV wind asset cashflows are re-simulated after *materially* curtailing plant operations and depressing spot prices. These risks are not intended to reflect market volatility. Rather, they are intended to reflect long-term or permanent changes to asset economics.

Before results are discussed, it is important to first establish parameters for a material default even, cf. a technical default event. A material default occurs when funds held within an asset's "debt service reserve account" (DSRA) are exhausted within a simulated twelve-month period. DSRAs are typically sized to six months of debt service obligations, which are held on reserve and are only accessible if cashflows are insufficient to meet repayments. By implication, a material default indicates debt service cashflows have persisted below repayment obligations by a magnitude of at least 1.5x within a single 12-month period, or $\sum_{q=1}^{4} DS_q^i \ > \ 1.5 \cdot \sum_{q=1}^{4} CFADS_q^i$. Hence, a material default is considered a *true depletion of cash*, necessitating that project banks forego interest charges and, in many cases, requiring a re-configuration and re-negotiation of the SPV capital structure. For simplicity, a material default is assumed to produce an additional net reduction to equity cashflows equal to 25%[24] of the initial equity commitment (in addition to cash lockups) – reflecting a loss of all future distributions as SPV shares are seized by lenders. This assumption produces Figures 10, 11 and 12, depicting equity cashflows for each investment case under material distress - viz. incremental generation curtailment, depression of spot prices and, finally, both distress variables combined.

[23] It is prudent to note that commentary on PPA limitations is relevant in so far as *typical* run-off plant PPA terms are assumed. Hypothetically, if a particular offtake contract were to include provisions designed to further shield asset revenues from generation variability, it is logical that cost of capital could be brought lower.

[24] While there is an arbitrary element to this 25% assumption, it should be noted that the true impact of a material default is ultimately dependent on the timing of the default in the context of a ~30yr asset life. Dividends received prior to default vs dividends anticipated will inform the absolute loss, along with consideration vis-à-vis time-value of money. Modelling a precise quantification of equity losses is outside the scope of this analysis, with this point sufficiently made by specifying that material defaults produce losses *in excess* of cashflow lockups.

Figure 10: Impact of Material Curtailment

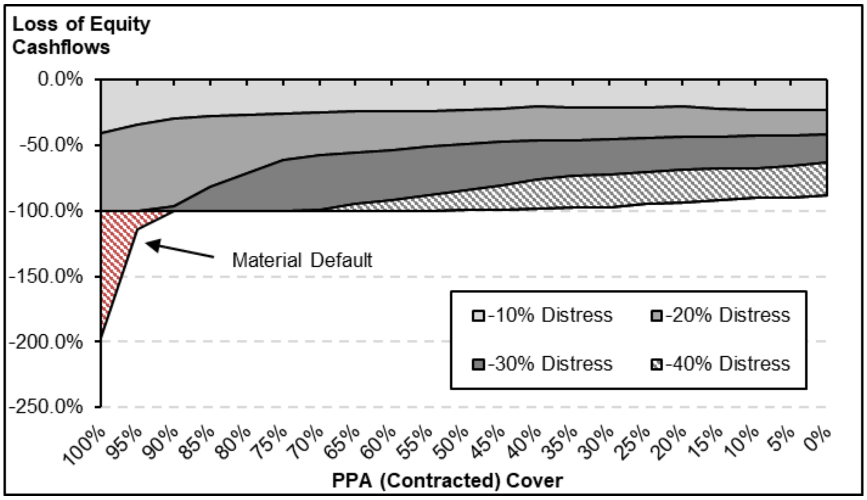


Figure 11: Impact of Materially Depressed Spot Prices

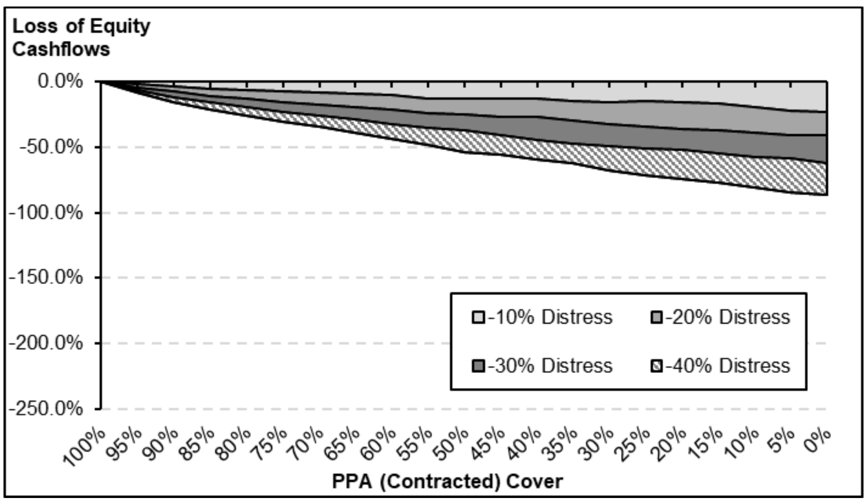
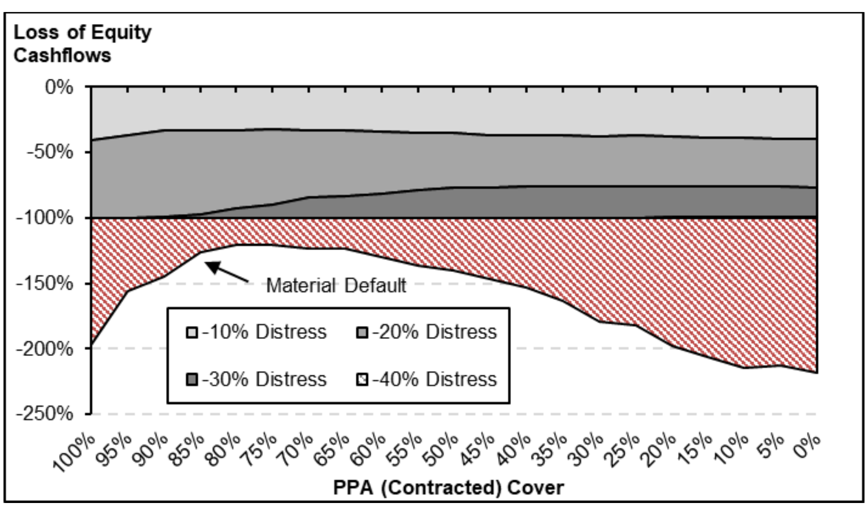


Figure 12: Impact of Material Curtailment and Depressed Spot Prices



While all PPA levels understandably struggle with prolonged periods of material distress, performance is not universal. Figure 10 indicates that low PPA cover is more capable of withstanding periods of material curtailment than higher PPA cover. In fact, only cases with the highest levels of PPA cover experience instances of material default when generation is curtailed at 40%. Likewise, Figure 11 illustrates the resilience of high PPA cover to spot price volatility - noting ~100% merchant assets do appear more resilient to spot price distress than ~100% PPA assets are to curtailment distress. Finally, the most instructive results are depicted in Figure 12, where material curtailment and material spot price distress are introduced simultaneously.

When both distress conditions are applied, it becomes clear that the semi-merchant structure, with a PPA cover between 65 – 85%, is the most resilient to material default. The relative stability of predominantly PPA revenues, combined with the flexibility of *moderate* spot market exposure, minimises the probability of bankruptcy for an investor. The counterfactuals – viz. highly PPA contracted or highly spot exposed, suffer from a lack of revenue flexibility and a compounding of distress conditions respectively. Layering stochastic variability with exogenous distress materially amplifies the risk to PPA contracted assets, meaning that a mix of PPA and spot market exposure appears *optimal* when facing material distress.

5.0 Implications for Investors and Policymakers

Model results carry implications for both renewable plant investors and for policymakers tasked with supporting new entrant capacity for VRE technologies.

5.1 Implications for Investors

For an equity investor seeking to optimise the capital structure of an SPV, the semi-merchant model with gearing in the range 60-70% presents an attractive option. These findings align with recent Australian experience, with an increasing number of new-entrant assets reaching financial close with well below 100% PPA revenue cover (Simshauser & Gilmore, 2022). Other works note that periods of above-average spot market prices may also offer an explanation for this trend – with the semi-merchant structure being a natural response to avoid “missing out” on supernormal profits (Gohdes, 2023; Gohdes et al., 2023). However, the results of this paper also present a more nuanced observation – that a PPA’s ability to hedge risk to equity capital does in fact have a limit within a non-recourse SPV structure. Above this limit, a PPA does not appear to extract additional risk from the asset, allowing Modigliani and Miller’s (1958) second irrelevance proposition to take effect and force equity investors to increase return requirements in compensation for the elevated distress risk of excessive gearing levels. Investors seeking the most favourable *risk-adjusted return* may benefit by securing finance against an asset with less than 100% PPA cover, while seeking to hold gearing constant. Moving from c.75% PPA cover to 100% does not appear to decrease the likelihood of default, but does hand the upside of merchant spot prices back to the PPA counterparty.

Model results imply the following decision tree for an equity investor seeking to deploy capital in VRE assets. For new-entrant plant seeking to optimise capital structure, an investor conceptually chooses between a fully contracted (100% PPA) asset yielding an IRR of c.8.0%, or an 80% contracted semi-merchant asset yielding an IRR of between 8.8 – 9.5% (depending on level of gearing), both of which carry the same risk of technical default at equivalent gearing levels. It should be acknowledged that these incremental c.0.8 – 1.5% returns are ultimately derived from volatile spot markets, meaning revenues will exhibit a greater monthly variance. However, depending on the discount between the asset's PPA strike price and spot price forecast, it is conceivable that spot market revenues would need to be materially depressed before falling below the PPA strike price. Recall the delta between the solved competitive PPA strike price and average dispatch weighted spot price forecast is c.26.9%. If there is no material trade off vis-à-vis default risk between semi-merchant and 100% PPA options, handing a c.26.9% price discount to the PPA counterparty may become less appealing. Indeed, contracting PPA revenues above 80% cover does not appear to add additional value to an equity investor – rather it extracts returns which are ultimately handed back to the PPA counterparty.[25]

Naturally, these results also carry implications for project banks and raise questions regarding a mechanistic approach to debt sizing for VRE under a stand-alone SPV structure. Project banks naturally carry a unique set of requirements and considerations given the priority of debt service obligations within a PF cashflow waterfall. Nonetheless, *requiring* equity investors hand excess value a PPA counterparty may not be the most conservative course of action for lenders - particularly if banks are assumed to take ownership of the SPV following a material default. Instead, seizing an asset which has maximised the value of cashflows, without introducing excessive levels of quarterly revenue volatility, may represent an optimal outcome for project banks.

5.2 Implications for Policymakers

For policymakers, these results provide guidance on the strengths and weaknesses of underwriting regimes designed to support new-entrant VRE investment. State-backed CfD schemes have been effective at accelerating investment in new capacity, providing a targeted policy option to promote investment in particular technologies within particular regions. However, their effectiveness has limits, particularly when State counterparties place limitations on revenue payments - viz. total payment caps, non-firm price floors, minimum generation obligations and negative price provisions. These results illustrate the issues created by quarantining generation volume risk within a highly PPA contracted asset – as doing so limits the effectiveness of the PPA to extract spot market risk and enhance bankability. Total payment caps, whereby total net payments made by the counterparty to the SPV are capped at an agreed quantum, are now commonplace for State-backed CfDs and inherently re-expose the generator to spot market risk irrespective of the level of PPA cover. Short of providing a complete revenue guarantee or capacity payment, contracted assets will remain exposed to spot market risk – a risk which capital providers should be expected to price accordingly.

By way of an example, the 2021 Victorian State Government's second CfD auction, coined Victorian Renewable Energy Target 2 (VRET2), was fully subscribed at launch. However, of the six projects awarded a VRET2 contract, only one has publicly announced financial close at the time of writing. While the commercial terms of each contract were not released to the public, proponents were said to be required to agree a

[25] Moreover, the counterparty to a run-of-plant PPA may benefit even further during negative price period, as the option remains to purchase the same volume of electricity at the prevailing negative price. In this sense, a PPA counterparty may benefit materially in circumstances where negative prices become more frequent – particularly if the buyer can on-sell electricity at >$0.0/MWh (e.g. if the counterparty operates a retail book).

maximum payment cap and were not protected from negative price risk.[26] These terms were understandably designed to protect taxpayers from making excessive payments if the CfDs ultimately became materially out-of-the-money. However, the results of this paper indicate these protections may have come at the expense of producing commercially viable VRE projects.

Finally, these results raise broader questions regarding the housing of risk, namely which parties (viz. stand-alone SPVs, private PPA counterparties or State/Federal Governments) are best placed to carry specific generation risks. While this paper does not claim to provide a complete answer, acknowledging the commercial challenges of quarantining volume risk within a stand-alone SPV under imposed project finance covenants reflects a key issue worthy of policymaker consideration. This issue arises before considering some of the wider consequences of State-backed underwriting schemes on hedging market liquidity - a topic which has been the worthy focus of other writings, see Simshauser (2019) and Flottmann et al. (2024).

6.0 Conclusion

As energy markets decarbonise, and as supply becomes increasingly dominated by VRE technologies, the implications of revenue intermittency become an imperative consideration for private capital investment. By modelling the operational variability of renewable generation, the limitations of traditional approaches to revenue underwriting have been illustrated, identifying the limits of a PPA to extract stochastic risk from a stand-alone VRE asset under project finance. Results carry implications for investors seeking to optimise SPV capital structure, as well as for policymakers tasked with stimulating new investment while protecting taxpayers from uncapped commodity price exposures.

The Australian case presents a useful reference point, where comparably low PPA strike pricing and relatively high spot prices have incentivised investors to adopt a ‘semi-merchant’ approach to revenue contracting. As global energy markets become increasingly dominated by VRE capacity, understanding the limits of capital markets to absorb stochastic risk is essential to prevent stalled investment for critical new-entrant capacity. Even more crucially, mapping current market practices onto traditionally accepted frameworks (viz. Modigliani and Miller’s (1958)) when analysing the ‘capital structure puzzle’ becomes highly instructive when testing these limits. Identifying the conceptual point at which revenue underwriting can no longer shield investors from MM’s second proposition, and hence identifying the point at which capital structure optimisations cease producing cost efficiencies, allows private markets and policymakers to make informed decisions vis-à-vis risk-allocation. While there remains more work to do unpacking the broader trade-offs of VRE revenue underwriting, understanding what a PPA *can* and *cannot* achieve is essential to facilitating a healthy investment environment.

[26] https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets/victorian-renewable-energy-target-auction-vret2

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Appendix I: Stochastic Production Model Logic

As noted in Section 3, modelling commences by calculating the implied wind capacity factor for the South Australian region in each 30-minute interval over the nine-year sample period. A.1 reflects this calculation, where C denotes the total nameplate wind capacity in the region, g denotes the total wind production in the region, cf denotes the calculated capacity factor and μ denotes the relevant 30-minute period.

$$\frac{g_\mu}{C_\mu \cdot 0.5} = cf_\mu \tag{A.1}$$

The capacity factor over a given month, m, and a given year, y can therefore be calculated according to A.2. The number of 30-minute intervals in a given month or financial year is denoted by ϑm and ϑy respectively.

$$cf_m = \frac{1}{\vartheta m} \cdot \sum_{\mu=1}^{\vartheta m} cf_\mu \text{ , and } cf_y = \frac{1}{\vartheta y} \cdot \sum_{\mu=1}^{\vartheta y} cf_\mu \tag{A.2}$$

The deviations in average plant performance during any given month is calculated with respect to the average performance over the nine-year sample period, denoted as ΔM, via A.3.

$$\Delta M_m = cf_m - \left(\frac{1}{9} \cdot \sum_{y=1}^{9} cf_y\right) \tag{A.3}$$

Once production deviations are calculated, the next calculation relates to the corresponding energy price deviation. In doing so the price is *dispatch weighted*, per A.4, where; p denotes the market spot price and wp denotes the price captured by the average wind plant.

$$wp_m = \frac{1}{g_m} \cdot \sum_{\mu=1}^{\vartheta m} p_\mu \cdot g_\mu \text{ , and } wp_y = \frac{1}{g_y} \cdot \sum_{\mu=1}^{\vartheta y} p_\mu \cdot g_\mu \tag{A.4}$$

where;

$$g_m = \sum_{\mu=1}^{\vartheta m} g_\mu \text{ , and } g_y = \sum_{\mu=1}^{\vartheta y} g_\mu \tag{A.5}$$

To minimise bias created by exogenously determined inter-year market price fluctuations, the corresponding deviation in price performance, ΔP, is calculated against the average price during each month's relevant financial year.

$$\Delta P_m = \left(wp_m - wp_y\right) \cdot \frac{1}{wp_y} \tag{A.6}$$

Equations A.1 through A.6 are applied to produce a sample of 108 distinct months (9 x 12 = 108) of wind performance data, covering both production and dispatch weighted price.

Finally, the sample of 108 monthly observations are bundled into 100 years of stochastic performance data. Doing so requires the original month be retained for each sample to account for seasonal variance in plant performance. Each stochastic year, denoted as i, is created by taking a sample of each month from the nine-year dataset, where:

$$i = \{Jan \in [1,9],\ Feb \in [1,9],\ Mar \in [1,9], \dots Dec \in [1,9]\}; \tag{A.7}$$

with a probability P of drawing a given sample month from the dataset being random per:

$$P[1,9] = 1 \text{ and } P[\{1\}] = \frac{1}{9} = \dots = P[\{9\}]. \tag{A.8}$$

The stochastic production model output therefore comprises 100 years of random, stochastic operational and pricing data, with $i \in [1, 100]$.

Appendix II: PF Model Logic

A2.1 Operations

In each annual period, costs are escalated at the inflation rate CPI, represented by π in period (year) t:

$$\pi_t = \left[1 + \left(\frac{CPI}{100}\right)\right]^t. \tag{A.9}$$

Total energy output G, denoted in gigawatt hours (GWh), is calculated as a function of installed capacity k, plant capacity factor CF and annual operating hours $YrHrs$ at time t:

$$G_t = \frac{CF \cdot k \cdot YrHrs_t}{1000}. \tag{A.10}$$

The convergent price of electricity P, denoted in \$/MWh, is a function of the assumed split between PPA contracted and spot revenues. Both the PPA price PPA, and the merchant spot price $spot$, are solved later within the model per A.29 while applying relevant equity return constraints. C denotes the proportion of PPA revenue cover:

$$P_t = \big(PPA \cdot C + spot \cdot (1 - C)\big) \cdot \pi_t. \tag{A.11}$$

Plant revenues, denoted by R, are hence:

$$R_t = G_t \cdot P_t\,. \tag{A.12}$$

Operational expenses, E, are calculated as the escalated product of operations and maintenance cost, FC, denoted in \$ / MW / year, and installed capacity k:

$$E_t = \frac{FC \cdot k \cdot \pi_t}{1000}. \tag{A.13}$$

Earnings before interest tax depreciation and amortisation (EBITDA) at time t is hence:

$$EBITDA_t = R_t - E_t \tag{A.14}$$

A2.2 Capital Expenditure

Capital expenditure includes the cost of plant acquisition as well as ongoing capital maintenance expenses. Each of these expenses are escalated at π_t. Capital expenditure at time t is calculated using the following decision rule:

$$if\ t\begin{cases}= 1,\ X_t = Capex + x_t \cdot \pi_t \\ \neq 1,\ X_t = x_t \cdot \pi_t\end{cases}, \tag{A.15}$$

where X_t denotes total capex during a given period. $Capex$ denotes plant acquisition cost and is calculated as the product of the assumed overnight capital cost and the installed capacity k. x_t denotes forecasted capital works required to maintain functional plant operating conditions.

A2.3 Taxation

During income years where tax losses occur, the PF Model carries losses forward to offset the taxation of future profits. Both the asset depreciation shield and capital depreciation shield are calculated using a straight-line depreciation method.

Taxation life is denoted by TL. Total depreciation shield S is calculated as the sum of asset and capex tax shields at time t:

$$S_t = \frac{Capex}{TL} + \frac{x_t}{(TL-t)} + \frac{x_{t-1}}{(TL-t-1)}\ . \tag{A.16}$$

The SPV pays a cash tax τ_t at the Australian corporate tax rate τ_c:

$$\tau_t = (EBITDA_t - I_t - S_t - l_t) \cdot \tau_c, \tag{A.17}$$

where l reflects tax losses carried forward from previous income years, per:

$$l_t = Min(0, \tau_{t-1}), \tag{A.18}$$

noting that I denotes interest costs, with formulae to follow.

A2.4 Debt Sizing

Cash flow available for debt servicing, $CFADS$, is calculated by subtracting capital expenditure, X, and tax, τ, from $EBITDA$ at time t:

$$CFADS_t = EBITDA_t - X_t - \tau_t. \tag{A.19}$$

Debt amortisation is *'sculpted'* for each period t via the applied debt service coverage ratio $DSCR$. $DSCR$ is informed by PPA revenue cover C, per:

$$DSCR = 1.30\ \cdot C + 2.40\ \cdot\ (1 - C). \tag{A.20}$$

Total debt service payments DS in each period, along with interest I and principal L, are solved via:

$$DS_t = CFADS_t \cdot \frac{1}{DSCR} = I_t + L_t. \tag{A.21}$$

The model is then tasked with iterating to solve the following functions simultaneously, in which D denotes the opening loan balance at time t, notional debt tenor is denoted by dt, refinancing fees are denoted by F, the all-in interest rate is denoted by ir and the refinancing rate is denoted by rr:

$$L_t = DS_t - I_t, \tag{A.22}$$

$$I_t = ir \cdot D_t, \tag{A.23}$$

$$if\ t \begin{cases} = \{7, 14, 21\},\ F_t = D_t \cdot rr \\ \neq \{7, 14, 21\},\ F_t = 0 \end{cases}, \tag{A.24}$$

$$D_t = D_{t-1} - L_t + F_t, \text{ and} \tag{A.25}$$

$$0 = -D_{t=1} + \sum_{t=1}^{dt} L_t - F_t. \tag{A.26}$$

Note that refinancing fees F are calculated on 7-year intervals and are capitalised into the outstanding loan balance. The applied interest rate ir is calculated as the sum of $BBSW$ and the credit spread cs (both denoted in basis points), which is informed by revenue PPA contract cover C, per:

$$ir = \left(BBSW + 180 \cdot C + 260 \cdot (1 - C)\right) \cdot \frac{1}{100}. \tag{A.27}$$

A2.5 Dividends and Equity Returns

Dividend payout Div_t is calculated by subtracting the cost of debt servicing, DS, from the cash available for debt servicing:

$$Div_t = CFADS_t - DS_t, \tag{A.28}$$

The model then iterates to solve for $P_{t=1}$, while applying a cost of equity ke where:

$$if\ C \begin{cases} = 1,\ k_e = 0.08 \\ = 0,\ k_e = 0.12 \\ > 0\ and < 1,\ k_e = 0.08 \cdot C + 0.12 \cdot (1 - C) \end{cases} \tag{A.29}$$

$$0 = -Capex + \sum_{t=1}^{N} \begin{pmatrix} (P_{t=1} \cdot G_t \cdot \pi_t) - E_t - DS_t \\ -((P_{t=1} \cdot G_t \cdot \pi_t) - E_t - I_t - S_t - l_t) \cdot \tau_c \end{pmatrix} \cdot (1 + ke)^{-t}, \text{ or}$$

$$0 = -Capex + \sum_{t=1}^{N} Div_t \cdot (1 + ke)^{-t}. \tag{A.30}$$

Note that N denotes the useful asset life.

Appendix III: Intra-Year Cashflow Model Logic

Asset cashflows for a single annual period t are informed by PF Model outputs. Annual cashflows are divided into twelve months $m \in [1, 12]$. Given that financing obligations are met quarterly, months are subsequently categorised into four quarters $q \in [1, 4]$, where:

$$m \begin{cases} = \{1, 2, 3\},\ q = 1 \\ = \{4, 5, 6\},\ q = 2 \\ = \{7, 8, 9\},\ q = 3 \\ = \{10, 11, 12\},\ q = 4 \end{cases}. \tag{A.31}$$

The quarterly cashflow waterfall is sequenced as follows.

Plant revenues during any given month R_m are drawn at random via a stochastic process. Revenues for each month are derived from the following function, in which i reflects a particular sample year per (A.7):

$$R_m^i = \left(C \cdot PPA_m + (1 - C) \cdot spot_m \cdot \Delta P_m^i\right) \cdot G_m \cdot \Delta M_m^i. \quad \text{(A.32)}$$

Note that $i = 0$ reflects the initial investment case. Recall also that C denotes the level of contracted PPA cover, G denotes energy production during a given period and $spot$ denotes the merchant spot price expectations of investors.

Cash available for debt servicing $CFADS$ for any given quarter q is therefore:

$$CFADS_q^i = \sum_{m \in q} R_m^i - E_m - \left(R_m^i - E_m - \frac{S_t}{12} - I_m\right) \cdot \tau_c. \quad \text{(A.33)}$$

Note that operating costs E and interest costs I continue to be calculated according to the PF Model methodology, per A.13 and A.23, albeit on a monthly basis. Debt servicing obligations remain calculated based on the initial investment case, $i = 0$, meaning:

$$DS_q = CFADS_q^{i=0} \cdot \frac{1}{DSCR}. \quad \text{(A.34)}$$

Finally, equity dividends are also paid quarterly after financing obligations are met, and are hence calculated as:

$$Div_q^i = CFADS_t^i - DS_q. \quad \text{(A.35)}$$

Crucially, equation (A.35) implies that Div is stochastically variable, due to debt servicing obligations and operating costs remaining constant across stochastic sample periods, while R fluctuates according to i. The 'live DSCR', $LivDSCR$, for each instance of i can therefore be calculated via:

$$LivDSCR_q^i = \frac{CFADS_t^i}{DS_q}, \text{ implying } LivDSCR_q^{i=0} = DSCR, \text{ and } LivDSCR_q^{i>0} = [0, \infty). \quad \text{(A.36)}$$

In the event that $LivDSCR$ falls below the lockup covenant threshold of 1.15x, a cash sweep is triggered for period q and adjacent periods, modifying A.35 to be:

$$if\ LivDSCR_q^i \begin{cases} \leq 1.15, & Div_{q=\{1,2,3,4\}}^i = 0 \\ > 1.15, & Div_q^i = CFADS_t^i - DS_q \end{cases}. \quad \text{(A.37)}$$

$LivDSCR$ of ≤ 1.15 is defined as a 'technical default'. Importantly, given that financing obligations are met on a quarterly basis, the asset must experience *multiple* sequential months of under-performance for a default to be triggered.

Distress costs are hence calculated as the delta between dividends payable under the investment case and during periods where $LivDSCR$ is less than the lockup covenant. This is denoted as $DisC$, per:

$$if\ LivDSCR^{i}\begin{cases}\leq 1.15, DisC^{i} = 0 - \ Div^{i=0} \\ > 1.15, DisC^{i} = 0\end{cases}. \tag{A.38}$$

Notably, the nonrecourse nature of the PF structure ensures that $DisC$ is never greater than the anticipated Div within a given sample i, hence:

$$\sum_{i=1}^{100} DisC^{i} \ \leq \ \sum_{i=1}^{100} Div^{i}. \tag{A.39}$$