EPRG WORKING PAPER

UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Non-Firm vs. Priority Access: on the Long Run Average and Marginal Cost of Renewables in Australia

EPRG Working Paper 2322

Cambridge Working Paper in Economics 2363

Paul Simshauser[♠♣] and David Newbery[♣]

Abstract

In Australia's National Electricity Market (NEM), 170+ renewable and battery storage projects reached financial close from 2016-2022, totalling 24GW and $46 billion. With an investment supercycle, not all projects arrive smoothly. Some investors experienced entry frictions from system strength constraints, adverse movements in Marginal Loss Factors and network congestion. Whether these outcomes – which impacted ~20% of entrants – represented workable results in a properly functioning market due to investment error, or arose because of market design defects requiring policy attention, is an open question. An issue that NEM policy advisors are seeking to reform is the non-firm, open access regime. Policy focus is warranted. The ratio of maximum to average wind output is ~3x while solar PV is 4x. Consequently as renewable market share increases, rising levels of curtailment are predictable through excess generation and negative price events, network congestion, or both. But care must be taken with access reform because well-intended 'intuitive policy prescriptions' can produce the exact opposite effects by constraining REZ asset productivity, compounding complexity and slow renewable entry rates – the critical variable being the difference between average and marginal curtailment rates. Malalignment between access policy and over-the-counter forward market conventions may distort entry, raise consumer prices and harm welfare.

Keywords Renewables, Network Congestion, Curtailment, Marginal Curtailment, Renewable Energy Zones.

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

♠ Centre for Applied Energy Economics & Policy Research, Griffith University.
♣ Energy Policy Research Group, University of Cambridge.

Non-Firm vs. Priority Access: on the Long Run Average and Marginal Cost of Renewables in Australia

Paul Simshauser♠♣ and David Newbery♣
October 2023

Abstract
In Australia's National Electricity Market (NEM), 170+ renewable and battery storage projects reached financial close from 2016-2022, totalling 24GW and $46 billion. With an investment supercycle, not all projects arrive smoothly. Some investors experienced entry frictions from system strength constraints, adverse movements in Marginal Loss Factors and network congestion. Whether these outcomes – which impacted ~20% of entrants – represented workable results in a properly functioning market due to investment error, or arose because of market design defects requiring policy attention, is an open question. An issue that NEM policy advisors are seeking to reform is the non-firm, open access regime. Policy focus is warranted. The ratio of maximum to average wind output is ~3x while solar PV is 4x. Consequently as renewable market share increases, rising levels of curtailment are predictable through excess generation and negative price events, network congestion, or both. But care must be taken with access reform because well-intended 'intuitive policy prescriptions' can produce the exact opposite effects by constraining REZ asset productivity, compounding complexity and slow renewable entry rates – the critical variable being the difference between average and marginal curtailment rates. Malalignment between access policy and over-the-counter forward market conventions may distort entry, raise consumer prices and harm welfare.

Keywords: Renewables, Network Congestion, Curtailment, Marginal Curtailment, Renewable Energy Zones.

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

1. Introduction

Australia has a renewable energy target of 82% by 2030. From 2016-2022, more than 170 wind, solar PV and battery storage projects totalling 24 GW reached financial close with investment commitments totalling A$46 billion, forming a renewable investment supercycle (Simshauser & Gilmore, 2022). Along with this fleet of Variable Renewable Energy (VRE, intermittent wind and solar) was a further 16 GW of rooftop solar PV (Simshauser, Nelson and Gilmore, 2023). By mid-2023, the National Electricity Market (NEM) had reached 35.7% renewable market share, with VRE comprising 29.1% made up of wind (13%), rooftop solar (10%) and utility-scale solar (6.1%).[1]

Despite early successes, lead indicators of NEM renewable investment commitments appeared to be slowing towards the end of 2023. Development Approvals for new wind and solar in Victoria and New South Wales over the period 2021-2022 were running at

♠ Centre for Applied Energy Economics & Policy Research, Griffith University.
♣ Energy Policy Research Group, University of Cambridge.
[1] The remaining ~6% making up the 35.7% aggregate comes primarily from hydroelectric schemes.

less than half the ~1.1GW and 1.7GW annual levels required to reach targets[2] (Rystad Energy, 2023). And in 2023, only two VRE projects had reached financial close at the time of writing. Surveys undertaken by Australia's Clean Energy Council over the past five years persistently feature at least three items as central concerns of renewable investors, viz.

i. complexity of grid connection,

ii. inadequate network hosting capacity, and

iii. proposals to alter the NEM's market design (viz. policy and regulatory discontinuity).

There is no question grid connection complexity has increased. But complexity is a technical necessity if power system security is to be maintained. Continual loss of synchronous coal generators and mass entry of 'grid following' asynchronous VRE has led to system strength shortfalls (i.e. low fault levels) in certain locations (Badrzadeh *et al.*, 2020; Hardt *et al.*, 2021; Qays *et al.*, 2023). Before Connection and Access Agreements can be finalised, extensive studies vis-à-vis Generator Performance Standards (s.5.3.4a of the NEM Rules) and System Strength impacts (s.5.3.4b) must be completed satisfactorily – a complex, costly exercise for renewable investors that typically adds six months to development lags.

Yet the irony to grid connection complexity is that processes required of renewable investors during the final stages of securing a Connection and Access Agreement – satisfying s.5.3.4a and s5.3.4b being necessary pre-conditions for Project Finance – follows a 'first ready, first served' approach. One outcome of being complex and costly is so-called *zombie projects* tend to be 'screened out', which provides *clear air* for legitimate projects to reach financial close and proceed straight to construction. By contrast, other significant energy markets including PJM, CAISO and Great Britain operate on a 'first come, first served' basis and as a result are characterised by *chronic connection queues* and a prevalence of *zombie projects,* creating multi-year lags for legitimate project entry (see for example Millstein et al., 2021; Seel et al., 2023).

The second investor concern – inadequate network hosting capacity – is perhaps unsurprising following the entry of 170+ projects during the 2016-2022 supercycle. VRE network hosting capacity appears to be increasingly constrained with project connections in NEM regions visibly trending from low cost, lower voltage existing substations (110kV, 132kV, 220kV) to 275kV, 330kV and 500kV entry points (Rystad Energy, 2023). Higher voltage connections are more capital intensive, face longer lead times, frequently involve greenfield cut-ins requiring new switching stations thereby compounding costs.

Renewable Energy Zone (REZ) initiatives in Australia's NEM are intended to create requisite new VRE hosting capacity. Each NEM region has followed a different REZ policy pathway. Centrally coordinated REZ augmentations in Victoria are confronting community opposition to transmission developments along with new laws on land access, both of which create commitment delays. In New South Wales (NSW), the

[2] On the other hand, Development Approvals in Queensland are running ahead of the 1.0GW target (Rystad Energy, 2023).

contestable framework being pursued is running years behind schedule[3] – contestability of ‘infrastructure development’ and ‘speed’ rarely being complementary attributes.

Queensland REZs have followed a market-led pathway. Two non-regulated (i.e. merchant) REZs on the Southern Downs and Western Downs have been triggered by ‘first ready’ cornerstone renewable investment commitments (i.e. large wind farms). Being merchant transmission assets, the REZ user charges are levied on connecting and anticipated future generators rather than directly allocated to end-use consumers via the Regulatory Asset Base (see Simshauser, 2021). Queensland’s merchant REZs have been delivered rapidly – from concept to expected energisation in less than three years, with capital costs for each 2GW REZ less than $200 million. Two more merchant REZs (at 2GW each) are under active development. As market-led investments, REZ commitments move in line with ‘anchor tenant’ renewable projects. VRE project lags in Queensland appear to be the result of two key issues, i). recent equipment cost increases (causing proponents to re-scale projects to spread fixed costs, which in turn results in re-permitting delays), and ii). the unintended consequences of a recent Rule change seeking to simplify System Strength remediation.[4] Both appear transient rather than structural, but delays have nonetheless emerged.

The third concern of renewable investors, *policy discontinuity*, relates to constant proposals to change NEM design elements of central importance to renewable investors – both equity and debt providers. The various proposals by policy advisors to alter the NEMs multi-zonal market design and non-firm, open access connection regime have been persistent throughout the renewable supercycle. To generalise, policy proposals appear to be motivated by entry frictions including system strength, changes in Marginal Loss Factors or network congestion (see Simshauser, 2021; Simshauser and Gilmore, 2022). These can be condensed down to two issues, i). adequacy of locational signals, and ii). the management of *congestion risk* arising from new investments.

Ironically, policy proposals appear to be viewed as unhelpful by Australian renewable investors with Bashir (2020) documenting the extent of this in some detail. Parallel proposals in Great Britain are being met with an equivalent reception by British renewable investors (see Gowdy, 2022). In the Australian case, Commonwealth and State Energy Ministers have thus far rejected *‘design tinkering’* proposals, based on investor feedback.[5]

The purpose of this article is to examine access reform proposals and associated *congestion risk*. Rising congestion is inevitable. As Newbery (2023b) explains, renewable market shares in power systems will be determined by plant Annual Capacity Factors (ACFs). In the NEM, wind ACFs are ~35-40% and solar ACFs are ~20-30%. Renewable peak to average production ratios on the other hand are determined by the inverse – wind farm maximum output is ~3x average production, and maximum solar output is ~4x average production. Holding all else constant, adding renewables will result in increasing levels of network congestion, more episodes of renewable output

[3] At the time of drafting the Central West Orana REZ had failed to reach a final investment decision after being flagged in 2020 (see https://www.transgrid.com.au/projects-innovation/central-west-orana-rez-transmission-wollar-substation-upgrade). It is unlikely to be commissioned prior to 2028.
[4] The Rule change was intended to facilitate a more efficient process for procurement of system strength services. However, the Rule involved 5-year services which fails to match renewable investor requirements, and price rigidity of declared services. Amendments to the Rule are currently being developed by NEM market institutions.
[5] The response by Commonwealth and State Energy Ministers also includes dismantling the Energy Security Board.

exceeding aggregate final demand,[6] or both – culminating in rising renewable curtailment. The key point is that *marginal curtailment rates* are multiples (3-4 times) *average curtailment rates*, so curtailment rates are set to accelerate.

With lead indicators of VRE investment commitments slowing, policy makers are focusing on creating the conditions to speed up and optimally locate renewable entry in Australia's NEM. Rising congestion in a renewables-based power system is predictable and its management is therefore important. Policy advisors are right to examine potential problems but care must be taken with access reform. Well-intended 'intuitive policy prescriptions' can produce the exact opposite effect – viz. constrain REZ asset productivity, compound complexity, slow VRE entry rates and associated investment commitments. Consequently, access reform requires thoughtful policymaking and a thorough understanding of the difference between average and marginal curtailment rates, and the relative impacts of each on consumers *and* renewable investors. Crucially, any such analysis must be viewed through the lens of the prevailing wholesale electricity spot market design and over-the-counter forward market conventions. Just as the world's major power systems comprise an array of market designs, any policy response to curtailment needs to be devised and adjusted to the relevant context.

The purpose of this article is to examine the impacts of average and marginal curtailment rates in a wholesale gross pool electricity market setting with imperfect expansion paths. This is an understudied topic across most of the world's major electricity markets. The following analysis is based on the principles and constructs set out in Newbery (2021, 2023a, 2023b), albeit adjusted for Australian market conditions. Specifically, we model a Queensland REZ with ~1800MW of network hosting capacity. Our suite of optimisation models commences by identifying generalised entry costs, followed by deriving the optimal mix of wind and solar in a radial REZ. Consistent with Newbery's (2021, 2023b) Irish and British data, we find marginal curtailment rates accelerate, and run at multiples of average curtailment rates.

We then analyse the impact of priority access and compare this to non-firm, semi-open access (i.e. with an implied aggregate MW restriction). Perhaps counterintuitively, the NEM's market design and forward market conventions mean priority access either constrains entry materially below efficient levels, raises consumer prices, or both. Yet in Great Britain, in contrast, the exact opposite prevails. The opposing outcomes can be explained by the respective wholesale spot electricity market designs and forward market conventions.

This article is structured as follows. Section 2 provides a review of literature. Section 3 introduces our models and data. Sections 4-6 review the results. Policy implications and concluding remarks follow.

2. Review of Literature

Decarbonising of our power systems presents sequential challenges for investors, power system planners and policymakers alike. For modest levels of renewables up to (say) ~10% market share, the main challenge was cost. Early-stage renewable deployment occurred before more learning curve effects and the economies of scale led to sharp falls in unit costs (see Newbery, 2018, Grubb & Newbery, 2018). Consequently, onshore wind and solar PV entry historically required some form of subsidy – typically by way of renewable certificate schemes (Nelson *et al.*, 2013), mandated renewable portfolio standards (Feldman and Levinson, 2023) or central auction for Contracts-for-

[6] Comprising consumer demand plus available battery or pumped hydro storages.

Differences (Newbery, 2023a). Klobasa *et al*. (2013) distinguish five kinds of price-based support schemes and one quantity-based or quota scheme. Technical challenges in this early stage of renewables deployment was easily managed,[7] and integration costs low (Heptonstall and Gross, 2020).

As renewable market shares move beyond ~10% and through to (say) ~20%, merit order effects became predictable and pronounced (Sensfuß et al., 2008; McConnell et al., 2013) including a rising incidence of negative price events (Antweiler and Muesgens, 2021), caused by legitimate needs to keep inflexible plant on the wires and/or distortive VRE subsidies that only pay on metered output. Merit order effects are complex and comprise various sub-components, viz. price impression effects (Edenhofer *et al.*, 2013; Hirth, Ueckerdt and Edenhofer, 2016), stochastic production effects (Johnson and Oliver, 2019) and thermal plant utilisation effects (Simshauser, 2020). As the latter become more acute, coal plant exit becomes predictable (Rai and Nelson, 2020, 2021) and merit order effects can reverse in a cyclical response (Felder, 2011; Dodd and Nelson, 2019; Simshauser, 2020).

Moving beyond ~20% and through to (say) ~50%, particularly in geographically diverse and sparsely populated networks like Australia's NEM, complex technical challenges emerge including system strength shortfalls (Qays *et al.*, 2023), deteriorating inertia (Newbery, 2021), sharply falling minimum loads (Simshauser and Wild, 2023) and concerns over meeting reliability constraints given the prevalence of intermittent resources (Billimoria and Poudineh, 2019; Billimoria and Simshauser, 2023). The progressive loss of thermal dispatchable plant in prior periods – at times in a disorderly manner – amplify these challenges (Nelson, Orton and Chappel, 2018; Dodd and Nelson, 2019; Nolan, Gilmore and Munro, 2022; Simshauser and Gilmore, 2022).

One challenge which may occur throughout these mid- and later phases are entry frictions, and specifically, post-entry VRE losses. Frictions constraining entry such as renewable project connection queues are reasonably well understood (Millstein *et al.*, 2021; Seel *et al.*, 2023). Identifying and quantifying specific sources of post-entry investment failure is important to ensure any policy response undertaken occurs with 'surgical precision' rather than creating mass disruption events (Simshauser, 2021). In Australia's NEM, sources of investment failure include pre-commissioning connection lags and hold-point testing (Gohdes *et al*, 2023), movements in Marginal Loss Factors, (Simshauser and Gilmore, 2020; Simshauser, 2021), requirements to remediate system strength (Simshauser and Gilmore, 2022; Qays *et al.*, 2023) and sharply rising levels of renewable 'curtailment' from either network congestion (McDonald, 2023), negative price events (Joskow, 2022), or excess supply (Newbery, 2023c).

To be clear, some 80% of the NEMs VRE projects have entered successfully notwithstanding universal connection lags (Simshauser and Gilmore, 2020, 2022; Simshauser, 2021), and as Section 1 alluded to – many of the frictions outlined above do not warrant policy change. Connection lags relating to system security assessments are a necessary process to maintain a reliable power system. Moreover, movements in Marginal Loss Factors are forecastable, and are a critical locational signal. Requirements to remediate system strength are also forecastable and a necessary source of connection complexity outlined in the pre-entry stages in Section 1 (Simshauser, 2021). Congestion, however, will rise in prominence and does require policymaker attention.

---

[7] The exception here is if renewable market share comprises primarily (very high) take-up rates of rooftop solar PV, in which case various voltage issues arise – see Simshauser, Nelson and Gilmore (2023).

Congestion indicates an increasingly constrained network. Adequacy of network hosting capacity and renewable *investment cycles* can be observed in other significant energy markets. The lead indicator of these cycles appears to be availability of network hosting capacity (Du and Rubin, 2018). The first renewable investment supercycle in ERCOT (Texas) centred either side of strategic anticipatory network investments in 345kV transmission lines forming Renewable Energy Zones (REZs). Subsequent investment cycles spanned a second REZ development period (Du, 2023). It is noteworthy that ERCOT renewable investment cycle nadirs coincide with rising network congestion (i.e. a signal of an increasingly constrained network) while investment rates accelerate soon after additional anticipatory REZ network capacity commitments have been made (Gowdy, 2022).

The literature on curtailment typically focuses on curtailment and congestion management (Bird et al., 2016; Joos and Staffell, 2018; Millstein *et al*., 2021; Newbery, 2021, 2023c; O'Shaughnessy *et al*., 2021). Numerous studies show that transmission planners who guide market decisions to optimal locations given prevailing network hosting capacity can materially enhance welfare (Sauma and Oren, 2006; Tor, Guven and Shahidehpour, 2008; van der Weijde and Hobbs, 2012; Munoz et al., 2015; Alayo et al., 2017; Munoz et al., 2017; Ambrosius et al., 2019; Wagner, 2019). By definition, establishing new network capacity via a REZ sends an strong locational signal to generation, noting that investment commitment decisions are driven by *ex-ante* expectations of forward prices and locational signals, not *ex-post* outcomes (Hadush *et al*., 2011; Eicke et al., 2020). The creation of REZ is invariably designed to mitigate existing congestion (Du and Rubin, 2018; Du, 2023). Simshauser, Billimoria and Rogers (2022) outline how VRE can be co-optimised in a REZ.

3. Models and Data

In order to assess the impact of average and marginal curtailment rates in a Renewable Energy Zone, we rely on two sequential models, i). PF Model, and ii). REZ Optimisation Model.

3.1 PF Model and Data

Our 'PF Model' is a conventional multi-period cash-flow program capable of simulating various generation technologies under a range of organisational structures and financing facility options – including corporate and structured project financings. It produces (generalised) Levelized Costs of Electricity but with a level of detail beyond typical LCoE calculations because structured finance and taxation variables are co-optimised within the model. Critical inputs for the present purpose are listed in Table 1 (plant technical parameters) and Table 2 (finance variables), all of which are broadly consistent with recent survey data contained in Gohdes et al., (2022, 2023) along with relevant updates to observed 2023 conditions.

Table 1: PF Model parameters (technical)

Variable Renewable Energy		Wind	Solar
Project Capacity	(MW)	1,000	500
Overnight Capital Cost	($/kW)	2,800	1,600
Annual Capacity Factor	(%)	35.0%	26.5%
Expected Avg Curtailment	(ppt)	0 - 3	0 - 3
Auxillary Load	(%)	1.0%	1.0%
Transmission Losses	(MLF)	0.980	0.970
Fixed O&M	($/MW/a)	29,940	20,000
Variable O&M	($/MWh)	0.00	0.00
Ancillary Services Costs	(% Rev)	-1.0%	-1.0%

Source: Gohdes (2022, 2023).

Note in Table 2 our financing structure is assumed to be split into two facilities, a 5-year Bullet (Term Loan 'B') and a 7-year Amortising (Term Loan 'A') facility – shorter dated (5-7 year) debt being the dominant tenor used by renewable developers in the NEM.

Table 2: PF Model parameters (financial)

Renewable Project Finance		
Debt Sizing Constraints		
- DSCR	(times)	1.25
- Gearing Limit	(%)	0.8
- Default	(times)	1.05
Project Finance Facilities - Tenor		
- Term Loan B (Bullet)	(Yrs)	5
- Term Loan A (Amortising)	(Yrs)	7
- Notional amortisation	(Yrs)	25
Project Finance Facilities - Pricing		
- Term Loan B Swap	(%)	3.95%
- Term Loan B Spread	(bps)	180
- Term Loan A Swap	(%)	4.05%
- Term Loan A Spread	(bps)	209
- Refinancing Rate	(%)	6.0%
Expected Equity Returns	(%)	8.0%

Source: Gohdes (2022, 2023), Bloomberg.

The full PF Model logic and how the assumptions in Tables 1-2 are used is set out in Appendix I.

3.2 REZ Optimisation Model and Data

Our REZ Optimisation comprises a structural LP Model of a radial, double circuit 275kV Renewable Energy Zone with multiple generator connections. Hourly intermittent wind and solar resource options are drawn upon and bound by REZ transmission line ratings. Critical variables for determining seasonal (or dynamic[8]) line transfer limits centre on conductor type and allowable operating temperatures under 'normal' and 'emergency' conditions. For the case at hand, a reference twin-sulphur aluminium conductor is assumed with normal and emergency operating temperatures of 75º and 90º C, respectively. This in turn leads to seasonal line ratings (50-200km from coast) as follows:

[8] While the REZ Optimisation Model contains the data and equations to derive dynamic line ratings, we have selected seasonal line ratings in order to enhance the focus on average and marginal curtailment effects in this research.

Table 3: Seasonal Line Ratings (Amps)

	Normal Rating (Amps)	Emergency Rating (Amps)
Summer	1734	2582
Mild Seasons	1981	2774
Winter	2162	2922

Source: Powerlink.

Seasonal power transfer capacity of a double circuit 275kV Renewable Energy Zone in the peak summer period $(REZ_{t=Sum}^{S})$ are identified in Eq.(1).

$$REZ_{t=Sum}^{S} = Min\big[\big(2 \cdot \sqrt{3} \cdot 0.275 \cdot NR_{t=Sum}^{S} \cdot 0.93\big), \big(\sqrt{3} \cdot 0.275 \cdot ER_{t=Sum}^{S} \cdot 0.93 + FCAS^{S}\big), \theta_{Sum}^{S}\big]. \quad (1)$$

In Eq. (1) the first term identifies static seasonal (superscript 'S') thermal transfer capacity for each conductor for each of two circuits (2 x √3 x 0.275 x Current) operating at Normal Rating $NR_{t=Sum}^{S}$ during summer (subscript t=Sum) and converted to MW assuming a power factor of 0.93. The second term in Eq.(1) repeats this process for a single circuit operating at its Emergency Rating $ER_{t=Sum}^{S}$ with a runback scheme enabled at the $FCAS^{S}$ level.[9] Appendix B illustrates how this occurs in practice. The third term θ_{Sum}^{S} is an exogenous constraint and can be thought of as a downstream fixed capacity limit (e.g. capacity of the substation). This produces the following maximum hourly power flow limits:

- Summer 2 x 768 MW = 1,534 MW
- Winter 2 x 958 MW = 1,916 MW
- Mild 2 x 878 MW = 1,756 MW

With line ratings established, the REZ Optimization Model seeks to maximise aggregate five-year wind and solar production (or profit if specified) subject to an array of constraints, including power transfer limits and maximum tolerable 'curtailment'. The model structure, which is largely based on Simshauser et al. (2022), is as follows.

Let $re \in RE$ be the set of wind and solar projects connecting to the REZ, each with installed capacity K_{re}^{re} and proportion of plant availability $\beta_{re,t}^{re}$. Let $t \in T$ be the set of dispatch intervals and $G_{re,t}^{re}$be output of generator re. At this point, the objective function becomes a relatively straight-forward one:

$$OBJ_{GEN} = Max\left(\sum_{t\in T}\sum_{re\in RE} G_{re,t}^{re}\right), \quad (2)$$

S.T.

$$G_{re,t}^{re} \leq K_{re}^{re} \cdot \beta_{re,t}^{re} \; \forall \; re \in RE, t \in T, \quad (3)$$

[9] Frequency Control Ancillary Services - Australia's NEM enables FCAS duties in a largely dynamic process driven by the single largest credible contingent event. Under normal system conditions this is typically the largest spinning generation unit (Kogan Creek) which is rated at ~750MW. Consequently 750MW of real-time spinning reserves over 6 second, 60-second and 5-minute periods are enabled by the market operator. If the unit is offline for maintenance (or operating at partial load) the quantity of FCAS enabled reduces to the next largest unit (typically 720MW in the adjacent region of New South Wales). Subsequent modelling assumes FCAS is 750MW unless otherwise specified.

$$\sum_{re \in RE} G^{re}_{re,t} \leq REZ^{S}_{t=Sum} \; \forall t \in T, \quad (4)$$

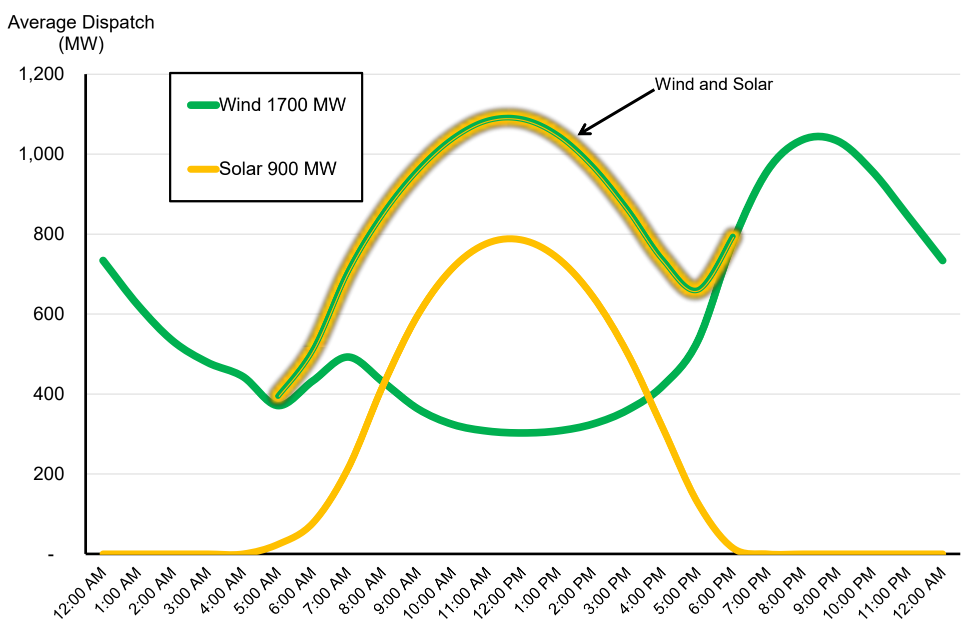
$$\sum_{re \in RE} G^{re}_{re,t} \geq (1 - \delta^{re}_{re}) \cdot e\left(G^{re}_{re,t}\right). \quad (5)$$

Eq. (2) sets the Objective Function noting the variable can switch between Production and Profit, as required. For our purpose, we focus on production given the overarching policy objective (noting that profit results are still monitored for 'tractability' of any production scenario produced). Eq. (3) limits generation to available capacity $K^{re}_{re,t}\beta^{re}_{re}$ while Eq. (4) constrains total generation in each dispatch interval $t \in T$ to the seasonal (or dynamic) line rating capacity $REZ^{S}_{t=Sum}$ in accordance with Eq. (1). Eq. (5) ensures the average REZ congestion and subsequent wind and solar curtailment (δ^{re}_{re}) impacting expected output $e\left(G^{re}_{re,t}\right)$ of the fleet of wind and solar projects do not exceed tolerable limits associated with a project finance.

The REZ Optimisation Model draws on hourly intermittent resource options (i.e. wind and solar) over a five-year window (2017-2021 data) for a given specified geographic location. In the present research, Queensland's resource-rich Western Downs area has been selected, with real-time weather re-analysis data for solar and wind resources from Gilmore et al., (2022).

The diurnal pattern of wind and solar from Queensland's Western Downs are complementary as Fig.1 illustrates. The relative pattern of wind is biased to evenings, with the middle of the day characterised by hot, relatively still, sunny conditions at which point solar PV output reaches its maximum.

Figure 1: Average Summer Production for Wind and Solar PV (2017-2021)



The seasonal average correlation between wind and solar production in Fig.1 is -0.71 (mild seasons = -0.75, winter = -0.69). However, the hourly data over the five-year period naturally exhibits much greater variability and a lower correlation of -0.28. Nonetheless, this basic complementarity between wind and solar PV on Queensland's Western Downs REZ area remains and Fig.1 helps explain the intuition behind subsequent model results – viz. *a priori* expectations of optimised wind and solar PV capacity within a 1,536 MW REZ will evidently vastly exceed 1,536 MW. In this simple example in Fig.1, average solar production output from 900MW of plant sits within the average wind output from 1,700MW of wind plant given the diurnal diversity of average output. However, only high-resolution modelling (e.g. hourly) can reveal the true extent of this diversity.

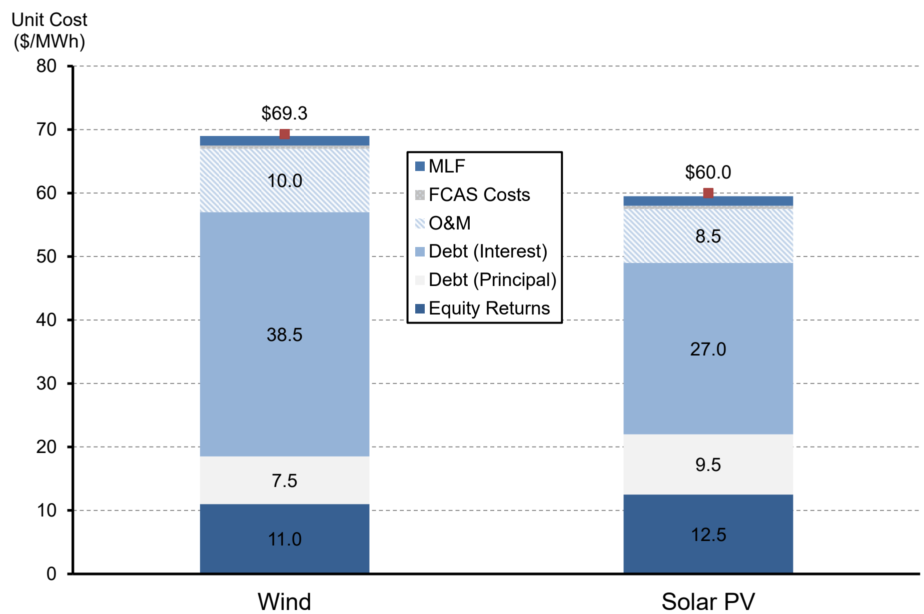
4. Model Results

Our analytical sequence commences with defining REZ entry costs for wind and solar PV given unconstrained dispatch. We then define the optimal level of wind and solar PV capacity connected to the radial REZ given transfer limits set out in Section 3.2. We then analyse average and marginal curtailment rates for each plant type under ever expanding levels of REZ line congestion.

4.1 PF Model Results – Entry Costs

Using our PF Model and the assumptions outlined in Tables 1-2, we derive entry cost results of $69.3/MWh for wind and $60/MWh for solar PV in an unconstrained state. Cost elements from the PF Model are illustrated in Fig. 2. Note Table 1 defined plant sizes to be 1,000MW for wind and 500MW for solar. In subsequent modelling we treat entry costs as perfectly divisible.

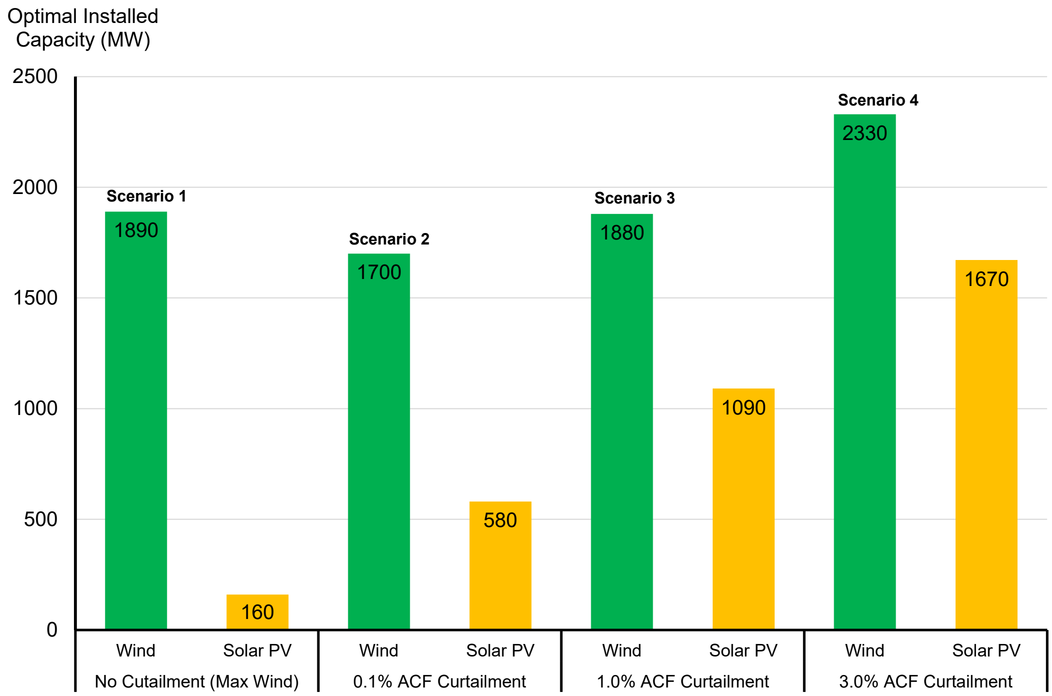
Figure 2: Entry Costs – Wind & Solar PV



4.2 REZ Optimisation Model Results – optimal mix of wind and solar

With the unit entry costs defined, the next step in our modelling sequence is to identify the optimal mix of wind and solar PV plant capacity that maximises aggregate final output or profit (as specified) over the five-year period 2017-2021 given REZ power transfer limits (Section 3.2, constrained by Eq. 4) and the 'tolerable' level of average wind and solar curtailment (constrained by Eq. 5). In the REZ Optimisation Model, we identify four scenarios – distinguished by congestion variable (δ_{re}^{re}) in Eq. 5 – set to 0 while prioritising wind, then 0.1%, 1% and 3% with no priority. Model results under each scenario are illustrated in Fig.3

Figure 3: Optimal Mix of Wind and Solar PV at differing Curtailment Rates



The purpose behind Scenarios 1 and 2 is to illustrate the difference between sequential versus simultaneous optimisation, and the sensitivity to even minimal levels of fleet-wide average curtailment. Recall from Table 1 that unconstrained Western Downs wind projects achieve average Annual Capacity Factors or ACFs of 35%, whereas unconstrained Western Downs solar PV will achieve average ACFs of 26.5%.

In the zero-curtailment scenario (Scenario 1), wind and solar PV are optimised in a sequential process. First wind is prioritised and maximised $(such\ that\ \delta_{re}^{re} = 0)$, and then in a second sequence, solar PV is maximised whilst ensuring zero curtailment. For both wind and solar, 'potential output' = 'practical output'. In this instance, the Model returns 1,890MW of wind (35.0% ACF) and 160MW of solar (26.5% ACF).

In Scenario 2, the congestion constraint is relaxed *slightly* $(\delta_{re}^{re} = 0.1\%)$ with wind and solar co-optimised simultaneously. Accordingly, in the model's dispatch process there is no priority for one technology over the other and where potential production output exceeds transmission line capacity REZ_t^S, wind and solar output are curtailed on a production-weighted equalised basis until the sum of instantaneous aggregate output $\sum_{re \in RE} G_{re,t}^{re}$meets the constraint set out in Eq. 4. This leads to a very different set of results to Scenario 1. In this second scenario, wind is reduced from 1,890MW to 1,700MW and solar PV is increased from 160MW to 580MW. Aggregate five-year output rises from 30,700GWh to 32,600GWh.

More importantly, however, are Scenarios 3 and 4, in which the congestion constraint is further relaxed $(\delta_{re}^{re} = 1\%, 3\%, respectively)$. Scenario 3 model results comprise 1,880MW of wind (almost identical to Scenario 1) but with much higher levels of solar PV – 1,090MW. Aggregate final production in Scenario 3 (40,200GWh) is 31% higher than Scenario 1.

Aggregate final production in Scenario 4, noting the 3% curtailment rate, is materially higher again at 49,900GWh – some 62% higher than Scenario 1 and ~24% higher than

Scenario 3. Consequently, if REZ network capacity is a scarce resource due to the cost of infrastructure and community limits to transmission line development, we should anticipate that installed generating capacity will vastly exceed nominal REZ transmission line transfer limits. However, this raises a critical issue – the difference between average curtailment rates and marginal curtailment rates, and the consequential impact on long-run average and marginal (renewable entry) costs and prices.

5. REZ Optimisation Model Results – average vs. marginal curtailment

Understanding network congestion risk is central to investment in intermittent renewables in the mid- to latter stages of the renewable transition because the incidence, prominence and financial impact of curtailment rates rise exponentially. In the early stages of renewable market entry with low market shares, congestion and associated curtailment risk was trivial to non-existent. Early wind entrants in Australia's NEM were classed as 'non-scheduled' generators – being small in size (i.e. less than 30MW capacity) and excluded from the formal dispatch process. Even as renewable generators increased in scale and became 'semi-scheduled' (i.e. above 30MW), their output could be comfortably accommodated by adjusting production levels of the NEM's vast fleet of coal, gas and hydroelectric generators – again because cumulative intermittent output remained small relative to aggregate final demand. However, as wind and solar PV capacity rises – and recalling that peak to average production for wind is 3x and 4x for solar PV – curtailment rates will gradually rise holding all else constant.

5.1 Principles

Consider the following scenario drawn from Pollitt & Anaya's (2016) analogy. Queensland maximum demand is currently ~10GW with aggregate final energy demand of 60TWh per annum. To meet reliability constraints, the (thermal) supply-side plant stock required a ~12% reserve plant margin, or 11.2GW of generating capacity in total. Average demand is 6.8GW and generation fleet-wide utilisation is ~61% (i.e. 6.8GW/11.2GW).

Now consider the same system with 50% renewables. The capacity factor of Queensland's 5.4GW of rooftop Solar PV is ~14.6%, and utility-scale wind and solar ACFs average ~35% and ~28% respectively. To meet 50% or 30TWh renewable market share, 6.0GW of wind and 4.5GW of solar PV capacity needs to be added to the 5.4GW of rooftop solar. Coincident output from this 15.9GW renewables fleet will likely range from as high as ~11 GW to as low as ~1 GW.

We therefore have a situation where 59% (15.9/[11.2+15.9]) of plant capacity is intermittent renewables, and potential renewable output could be as much as 200% (11/6.8) of average system demand, or as little as 15% (1/6.8). Thermal plant utilisation then falls from 61% to 32% and will test technical limits under security-constrained dispatch. It should also be obvious that 11GW of simultaneous 'potential' renewable output is not viable when average system demand is 6.8GW – and thus wind and solar plant will be curtailed during any mismatch. To be sure, battery or pumped hydro storage added to the power system will serve to delay curtailment rates. But storage is costly and power systems are still dominated by largely inelastic demand and so we should anticipate gradually rising levels of curtailment over time.

5.2 Marginal vs Average Curtailment Results

Returning to REZ Optimisations, we have populated the Model with 1,400MW of wind and 280MW of solar PV to commence simulations in an unconstrained state. In an iterative routine, we have then simulated two Optimisations:

1. Holding solar PV constant at 280MW, raising wind capacity in 10MW increments from 1,400MW through to 3,300MW.

2. Holding wind constant at 1,400MW, raising solar capacity in 10MW increments from 280MW through to 2,280MW.

Figure 4 illustrates the results from Optimisation #1. Note that at 1,400MW of wind installed at the LHS of the x-axis, the Practical Average (i.e. dispatched) ACF equates to 35%, which is exactly equal to the potential ACF of 35%. As wind capacity installed progressively increases from 1,400MW to 3,300MW as identified on the x-axis, the Practical Average ACF deteriorates from 35% through to 29.8% - identified by the solid dark blue line. At 3,300MW, the 29.8% result equates to the 'fleet-wide' Practical Average ACF. The commensurate fleet-wide average curtailment rate is identified by the solid light blue line and rises from 0% Average ACF Curtailment to 5.2% Average ACF Curtailment (i.e. 35% ACF – 29.8% ACF = 5.2% average curtailment rate). To be perfectly clear on this, these are 'fleet average' results.

Now consider a marginal MW installed. Once the installed wind capacity reaches ~1,500MW as measured on the x-axis, curtailment commences. And as each incremental MW of wind is added, marginal curtailment rises sharply. The dashed dark blue line shows that the final 10 MW installed on the x-axis (i.e. moving from 3,290MW up by 10MW to 3,300MW) achieves a Practical Marginal ACF of just 15.0% (identified via the dotted dark blue line) and a commensurate Marginal ACF Curtailment of 20.2% (i.e. 35% ACF – 15% ACF = 20% marginal curtailment rate). Put another way, the last 10MW installed along the x-axis produces about 40% of the first 10 MW installed on a priority dispatch basis and the ratio of the average to marginal curtailment is ~4x (that is, 20.2% ÷ 5.2%).

Figure 4: Optimisation #1 – Average vs Marginal Curtailment - Wind

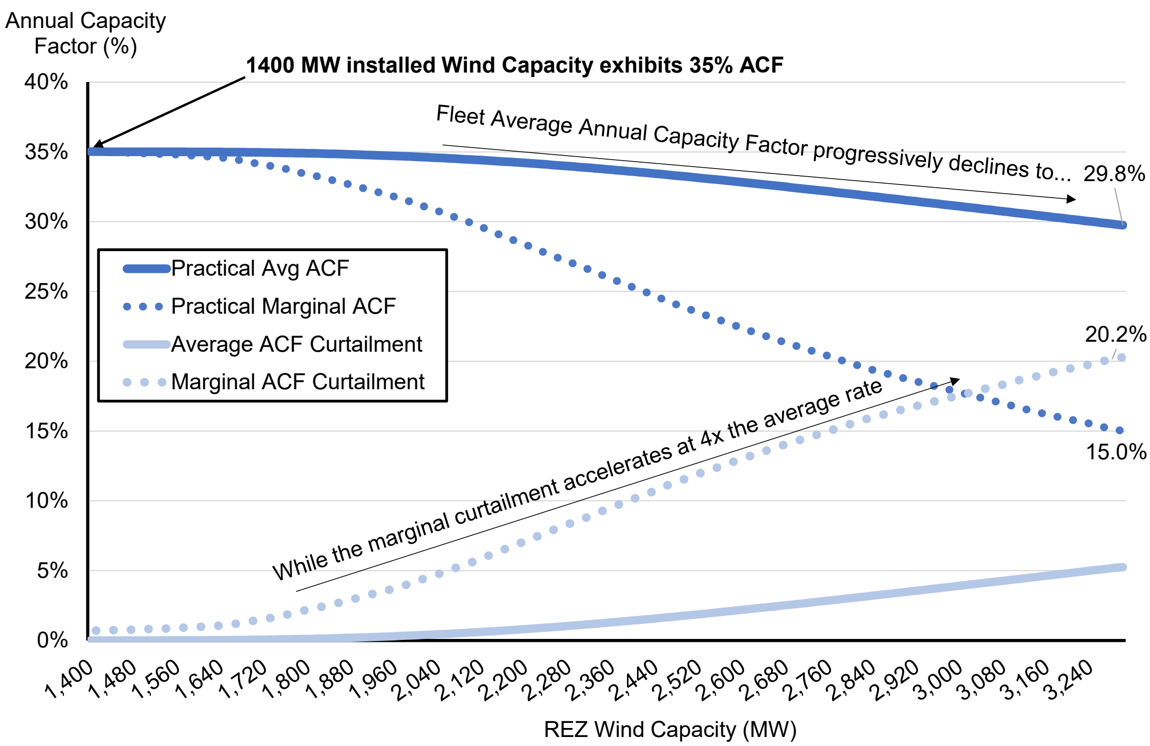
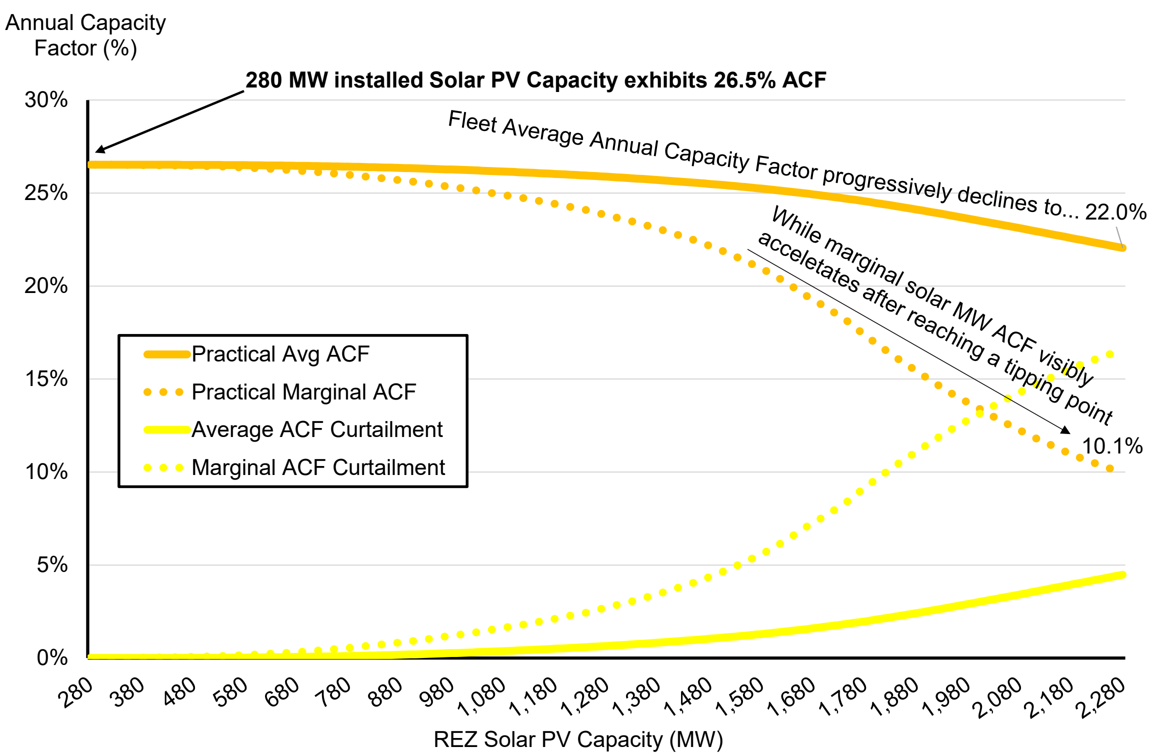


Figure 5 presents the results of Optimisation #2, which holds wind constant at 1,400MW and increases solar from 280MW to 2,280MW in 10MW increments along the x-axis. The results in Fig. 5 vary from the Fig. 4 wind results in one important respect – the stochastic nature of wind output occurs across a 24-hour period, and, it is rare that maximum wind output is reached throughout the year. For example, a 100MW wind farm on Queensland's Western Downs would produce 95 MW or more in a single trading interval for just 73 hours out of the 8,760 hours per annum (i.e. 0.8% of productive hours). Conversely, there are approximately 4,900 hours of viable solar production, and at least 400 of these will exceed 95MW of solar output on Queensland's Western Downs (8.1% of productive hours). Consequently, with greater predictability of reaching maximum production output, we should anticipate solar will reach a tipping point faster, and thereafter experience an aggressive downward marginal trajectory (absent localised storage).

Figure 5: Optimisation #2 – Average vs Marginal Curtailment – Solar PV



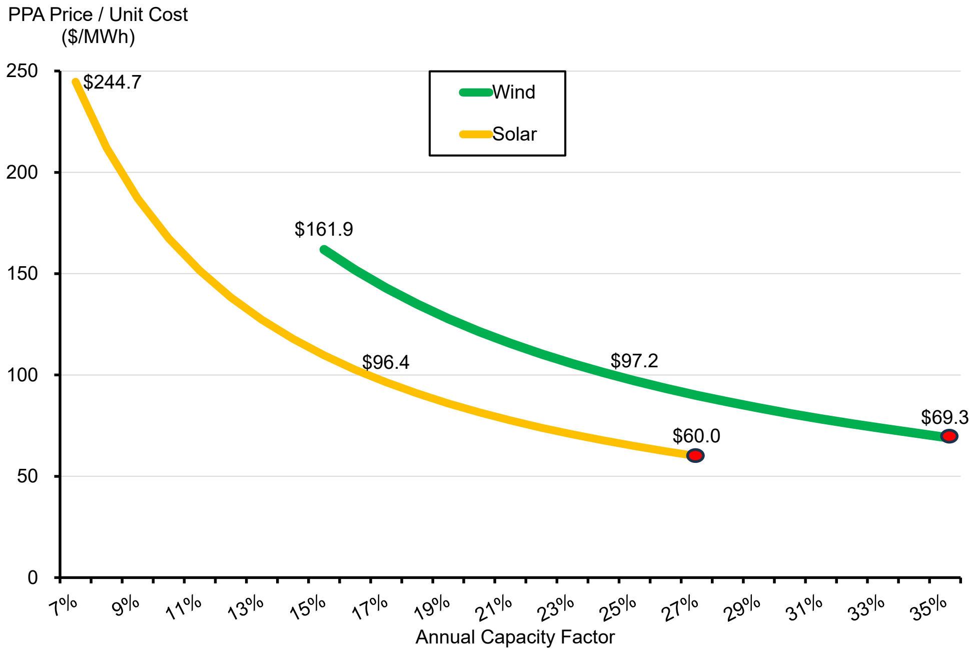
6. Long Run Average Cost vs. Long Run Marginal Cost

The stark contrast between average curtailment rates and marginal curtailment rates in Optimisations #1 and #2 (Figs.4-5) have material ramifications for the cost of new entrant plant, incumbent generators and consumer prices given the NEM's current and emergent market institutions, conventions and policy alternatives. Before examining these impacts specifically, we return to our PF Model and simulate the impact of curtailment on entry costs under the range of average and marginal curtailment observed in Figs. 4-5.

6.1 PF Model Results – Curtailment Entry Costs

The PF Model has been run on an iterative basis using the assumptions set outlined in Tables 1-2 with continuously adjusting ACFs and the assumption of perfect capital cost divisibility. Simulations have been iterated from 15-35% ACF for wind, and 8-26.5% for solar PV. The long run entry cost curves are illustrated in Fig. 6. Note that the long-run marginal cost per MWh falls as higher ACFs (or lower curtailment) increases the MWh/year delivered per MW capacity.

Figure 6: PF Model: Plant Long Run Marginal Costs



6.2 REZ Optimisation Model results

To complete our modelling, we combine entry costs from Fig. 6, average and marginal curtailment rates from Figs. 4-5, and hourly historic spot prices from the Queensland region of Australia's NEM over the period 2017-2021. Time-stamped renewable resources and historic spot prices are appropriately matched by hour – noting prices are fixed (assumed unaffected by VRE output) and in hindsight. The implicit and simplifying assumption here is that Western Downs VRE entry is matched by equal and opposite supply-side thermal plant adjustment or exit across the balance of the NEM. Noting this simplifying assumption, combining the REZ production and spot price data enables our REZ Optimisation Model to produce average and marginal revenue and cost curves for the 2017-2021 period. A statistical summary of observed spot prices is as follows:

Table 4: Statistical summary of Queensland spot prices (2017-2021)

Spot Prices (2017-2021)	($/MWh)		Annual Average Spot Price	($/MWh)
Average - 5-Yr	75.59		2017	102.46
Min price	-1,000.00		2018	74.79
95th Percentile Price	18.44		2019	71.84
5th Percentile Price	134.72		2020	41.26
Max Price	15,000.00		2021	87.70
Kurtosis	1,568.33		5-Yr Average	75.59
Skewness	34.48			
Wind - Dispatch Weighted	76.73			
Solar - Dispatch Weighted	70.23			
Wind - Dispatch %	1.02			
Solar - Dispatch %	0.93			

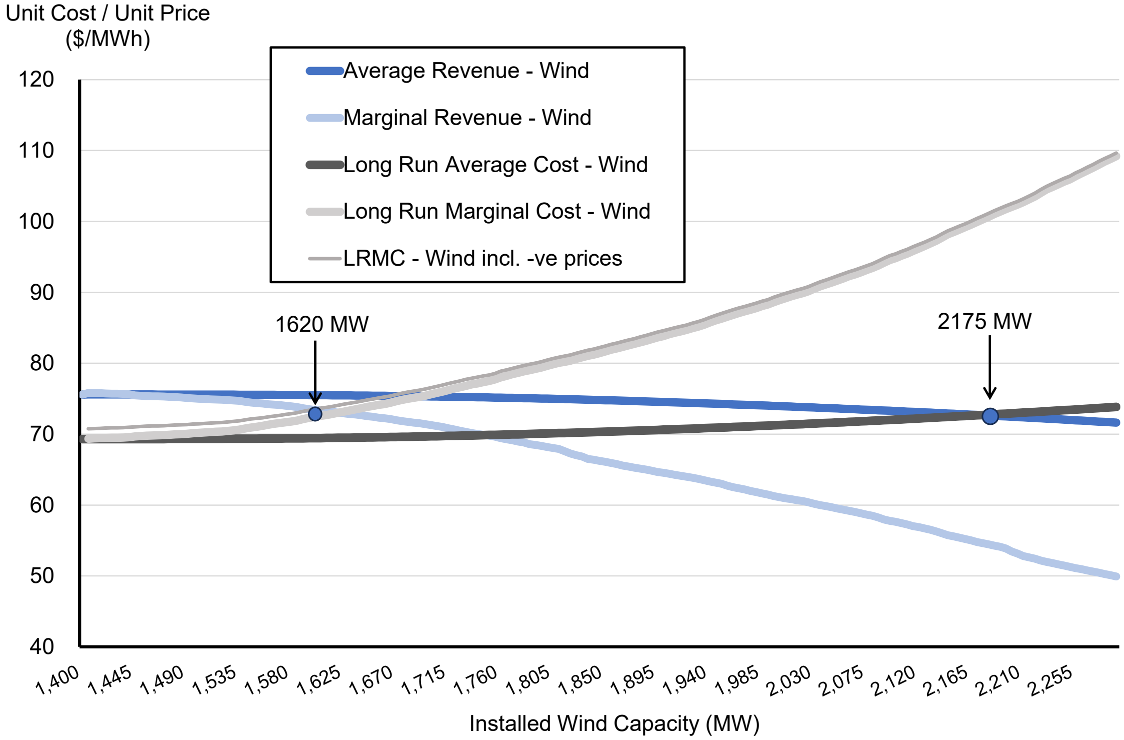
The REZ Optimisation Model iteration process in this instance differs slightly from the model setup in Optimisations #1 and #2. Recall Optimisation #1 held solar constant at 280MW and then iterated wind from 1,400MW to 3,300MW in 10MW increments. In the subsequent analysis, wind and solar continue to start at 1,400MW and 280MW as per Optimisations #1 and #2, but in Optimisation #3 (below) wind and solar are simultaneously increased by 5 MW each.

Model results for wind appear in Fig. 7. In Fig. 7 note the Long Run Average Cost – Wind curve (thick black line) commences at the PF Model's preferred result of $69.3/MWh (per Figs. 2 and 6) – consistent with a wind project operating unconstrained at 35% ACF. Average curtailment of wind trends from 0% at 1,400MW and gradually increases to ~5.4% at 3,300MW of installed capacity. Consequently, wind ACFs started at 35% and gradually deteriorated to a fleet average result of 29.6%. It can be seen from the Fig. 6 wind cost curve (green line series) that, from right to left, average cost starts at $69.3 (35% ACF) and rises to ~$76.5/MWh (29.6%). In Fig. 7, this result is reflected by the solid black (gently) upward sloping curve denoted 'Long Run Average Cost – Wind'.

Conversely, recall from Fig. 4 that the 'marginal curtailment rate' of wind deteriorated at 4x the average curtailment rate. Consequently the Practical Marginal ACF started at 35% and collapsed to just 15%. Fig. 6 notes a wind farm with a 15% ACF will have an entry cost of $161.9/MWh. The Fig. 7 y-axis has been truncated at $120/MWh and 3,300MW to enhance legibility. Nevertheless, the sharp contrast between the wind fleet's Long Run Average Cost (solid black line) and Long Run Marginal Cost (solid light grey line) is evident. Likewise, so too are the average and marginal revenues arising from spot prices over the period 2017-2021, albeit noting the caveats around entry/exit assumptions of using a fixed spot price data series.

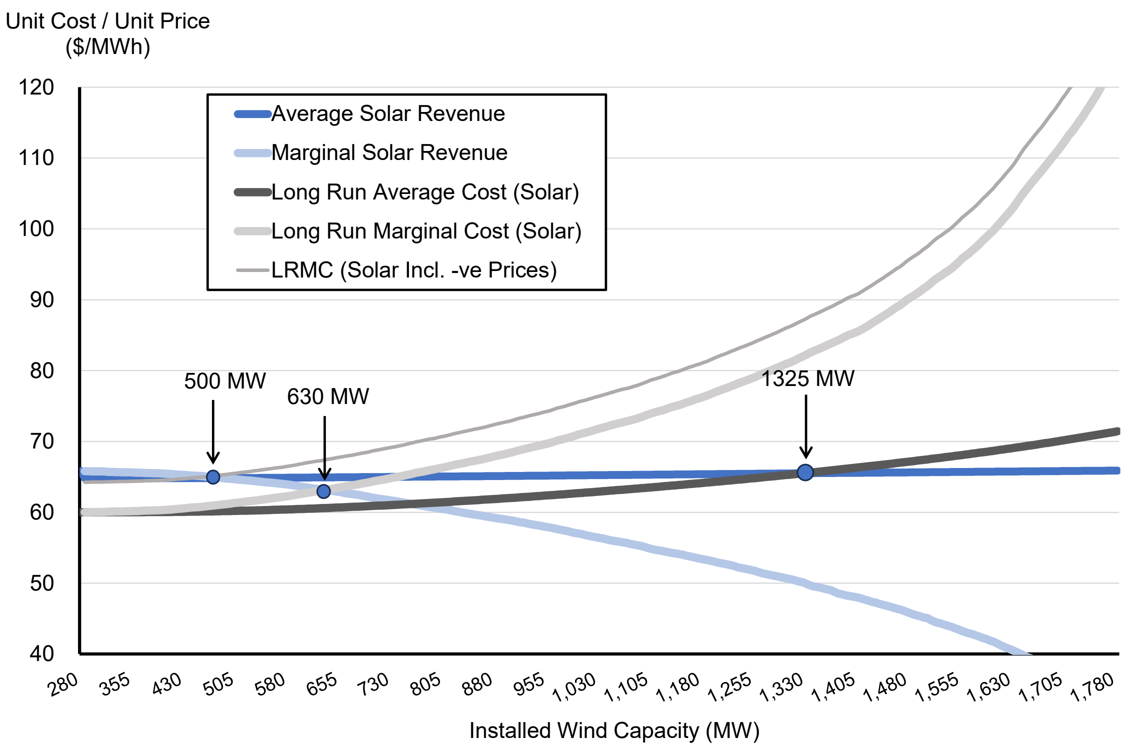
Of utmost importance to our subsequent policy analysis are the points of intersection. In a market in which ***average curtailment*** is observed in pricing, equilibrium results will trend towards 2,175 MW of wind at prices of ~$73/MWh. In a market in which ***marginal curtailment*** is observed in prices, equilibrium can be expected to deliver 1,620 MW of wind capacity at broadly equivalent prices. To push a marginal curtailment market any harder viz-a-viz delivering additional capacity will drive clearing prices along the upward sloping Long Run Marginal Cost – Wind curve.

Figure 7: Optimisation #3 Long Run Average vs. Marginal Cost (Wind Fleet)



Similar results can be seen for solar PV in Figure 8. For a market in which average curtailment rates are observed in pricing, 1,325 MW will be delivered in equilibrium. Conversely, for a market in which marginal curtailment rates are observed, 630 MW will be delivered in equilibrium (practical output) and after accounting for negative prices, only 500 MW.

Figure 8: Optimisation #3 Long Run Average vs. Marginal Cost (Solar Fleet)



7. Implications for non-firm vs. priority access and concluding remarks

What are the welfare maximising policy implications arising from our model results? In Australian and British electricity markets, the existing open access regimes and zonal spot prices mean renewable investment commitments face the economic consequences of 'average' curtailment rates. Prima facie, average (rather than marginal) curtailment and hence pricing appears inefficient. However, the policy implications of our work for access policy are not that clear cut.

The efficiency and welfare implications of marginal vs. average curtailment rates depends on an array of other variables including the availability of renewable resources, the extent of development limitations, wholesale spot electricity market design, the access regime itself (i.e. firm vs. non-firm) and market conventions in over-the-counter forward markets – these latter two variables being of utmost importance.

As it turns out, although average versus marginal curtailment rates are common to Australia and Great Britain, the welfare maximising solution is different for each market. There are important differences in the respective spot market designs and forward market conventions.

In Great Britain, renewable generators are granted permanent firm access and so are paid for energy produced and any energy curtailed. If a wind generator is curtailed for any reason, they are compensated for the lost profit of the curtailed energy, paid by consumers. British consumers therefore (currently) bear the risk and financial consequence of renewable plant curtailment – including poor locational decisions. Renewable investors enter with a form of synthetic firm access in a zonal market setup in which annual grid charges vary by zone. With a single zonal wholesale price, no Marginal Loss Factors (MLFs) and curtailment risks borne by consumers – unsurprisingly – there has been an excess entry result in the north of Great Britain (Scotland) where wind resources exceed network transfer capacity to the south where major load centres are located.

Entry in the British market continued in Scotland in the presence of known and rising network congestion. The cost of re-dispatch and curtailment-payments arising from constraints south of Scotland frequently run to as much as 10-30% of market volumes, with estimates of the 'balancing mechanism uplift' trending towards £4-6 billion per annum (Gowdy, 2022; Newbery, 2023a). To put this situation into perspective by reference to Figures 7-8, market conditions in Great Britain are the equivalent of producers facing the Long Run Average Cost and Revenue curves, while consumers pay prices that follow the trajectory of the steep, upward sloping Long Run Marginal Cost curves. These market conventions have resulted in research into altering the contracting arrangements (Newbery, 2023a).

The Australian case is the *opposite*. NEM spot market design and market conventions in the over-the-counter forward markets for swaps, caps, Power Purchase Agreements (PPAs) and Contracts-for-Differences (CfDs) internalise risks of renewable curtailment. In the spot market, wind and solar PV generators are paid for energy exported in each trading interval and adjusted by its MLF. A renewable generator with a CfD is therefore paid as follows:

Spot Revenue = (*MWh exported* x *MLF*) x Spot Price (6)

Contract Revenue = (MWh exported x MLF) x (CfD Price – Spot Price) (7)

Total Revenue = Spot Revenue + Contract Revenue (8)

Note in Eq. 6 and Eq. 7 there are no side-payments for curtailment.[10] In aggregate, renewable producers and specifically equity investors, *not consumers,* bear the risk of curtailment as they are in the best position to manage such risks. Furthermore, it is a default market convention that forward instruments reference the zonal price at one of the five regional reference nodes (i.e. Queensland, New South Wales, Victoria, South Australia, Tasmania). What this means is that for forward instruments, the risk of subsequent changes to a renewable plant's site-specific MLF also resides with renewable investors. Renewable investors therefore face two dimensions of locational risk. The first dimension is congestion and system strength risk. The second dimension is the NEM's direct locational signals comprising the (multi-) zonal spot and forward prices, and, the ~1,400 site-specific MLFs ascribed to each bulk supply point.[11] As Eicke et el. (2020) explain, the combination of these latter two variables (i.e. zonal prices and MLFs) transmit amongst the strongest locational signals of the world's major electricity markets, including well known nodal markets such as PJM and ERCOT (Eicke, Khanna and Hirth, 2020).

What REZ market outcome might therefore prevail in the NEM given the existing non-firm, open access regime? And how might this change if it were altered to a 'priority access' regime? The existing non-firm access regime implies equal dispatch rights for all connected generators in a REZ with production-weighted pro-rata sharing of curtailment. Priority access on the other hand implies some form of ranking, and synthetic priority dispatch right to connecting VRE generators (i.e. presumably in the order of entry: last-in, first-out of the dispatch process) in the REZ. These two regimes produce strikingly different outcomes given Australia's National Electricity Market Design. Taking our ~1,800MW REZ as the example:

- A decision to pursue priority access has the intended effect of guiding the REZ market along the *marginal curtailment* curve and therefore the *long run marginal cost* trajectory, which as Fig. 7 notes is a steeply rising curve.

- Using the applied example from Fig. 7 and market data from 2017-2021, it can be determined that, on a priority basis, we should anticipate 1,620MW of wind being developed at prices of ~$75/MWh – the point of (private) profit maximisation. The reason for this result is that each incremental MW of wind bears the risk of 'marginal curtailment'. Early entrants are granted priority access to REZ power transfer capacity. New entrants access 'residual' REZ capacity, and as more plant enters, their curtailment rates rise exponentially.

- The market clearing price required to deliver 2,175 MW of wind in a priority access regime within this REZ would be ~$100/MWh (see Fig. 7 Long Run Marginal Cost – Wind).

- The same principles apply in Figure 8. Under a priority access regime, solar entry in equilibrium would be 500MW given market data from 2017-2021. To deliver 1,325MW of solar, daytime average clearing prices would need to rise to ~$87.

[10] Counterparties to a PPA may agree on alternate terms but would do so only on a risk-adjusted basis.
[11] MLFs are adjusted each year to their expected (year-ahead) value and will fall with increasing current as capacity increased.

To summarise, a decision to allocate priority access rights to new entrant projects in the NEM would guide the relevant renewable curtailment variable to ‘marginal rates’. In economics, marginal costs and prices are generally said to be more efficient than average. *If* there was endless transmission hosting capacity and *if* communities were ambivalent to renewable developments, it may well be more efficient.

But this is not the environment that policymakers are facing. Even in a vast geographic state like Queensland such conditions do not hold. There are limits to development in every community. And, marginal costs and prices are not exclusively more efficient than average costs and revenues in equilibrium, particularly when short run marginal costs are close to zero. There are many applied examples where the underlying assumptions which drive the efficiency of the classic microeconomics result break down, and policymakers and regulators step in to guide markets and firms to average cost and price outcomes to maximise welfare over the otherwise strict profit maximising result (the regulation of monopoly transmission network utilities being a case in point).

In the case of Australia’s NEM, by comparison to priority access it would seem the existing non-firm, open access regime is capable of producing a welfare enhancing result with one important caveat:

- The NEMs existing non-firm access regime guides the market along the *average curtailment* path, and therefore the *long run average cost* curve and its gently upward sloping trajectory.

- By reference to Figure 7 and 2017-2021 market data, it can be determined that under the non-firm, open access regime, we should anticipate 2,175 MW of wind being developed, and over time, we should anticipate PPA clearing prices paid by consumers to rise to ~$75/MWh. The reason for this is that the wind investors share access to the REZ power transfer capacity and share the burden of curtailment.

- The same principles apply in Fig. 8, where the market can be expected to deliver the 1,325MW of solar capacity with the price drifting to $65/MWh as the capacity is delivered over time.

- The one important caveat is that policymakers may need to consider whether some form of time-limited, aggregate capacity restriction is placed over a given REZ and nearby transmission assets to guide (i.e. limit) cumulative curtailment rates for the investor market.

To simplify the comparison with a target of 2,175 MW of wind capacity, a priority access regime requires a clearing price of $100/MWh whereas the non-firm, open access regime is in equilibrium at $75/MWh. The welfare maximising result is the non-firm open access regime. In addition, open access (average curtailment) has the advantage of extracting some rent from early entrants and so reducing costs to consumers.

For producers, the risk of curtailment is as it has always been – a forecastable risk. And the extent of this risk in any given location will be regulated by equity investors and risk averse project banks after accounting for expected (zonal) spot and forward prices, forecasts of Marginal Loss Factors, and likely network congestion of the current location and in the context of the broader market.

For new entrants, curtailment rates should rise in line with average curves. PPAs are time-limited and on maturity, resets will no doubt incorporate prevailing expectations of curtailment-adjusted new entrant costs. And as Gohdes et al., (2022, 2023) recently observed, equity Internal Rates of Return associated with renewable projects in the NEM present as efficient, stable and with investors increasingly taking on some element of merchant exposure – a risk-adjusting mechanism to accommodate the array of uncertainties facing all generation projects.

There is some unintended residual risk in the NEM's dispatch algorithm in which a connecting generator 'just upstream' of a REZ may be inadvertently 'gifted' with a favourable constraint coefficient which in turn simulates priority dispatch. One out-working of this article is that NEM policy advisors should work towards better risk sharing than worse, for example, by "rounding" constraint coefficients and equations so as to avoid *false precision*.

8. **References**

Alayo, H., Rider, M.J. and Contreras, J. (2017) 'Economic externalities in transmission network expansion planning', *Energy Economics*, 68, pp. 109–115.

Ambrosius, M. *et al.* (2019) *The role of expectations for market design - on structural regulatory uncertainty in electricity*. Energy Policy Research Group, Working Paper No.1914. University of Cambridge.

Antweiler, W. and Muesgens, F. (2021) 'On the long-term merit order effect of renewable energies', *Energy Economics*, 99. Available at: https://doi.org/10.1016/j.eneco.2021.105275.

Badrzadeh, B. *et al.* (2020) 'System Strength', *Cigre Science & Engineering*, 20(Feb), pp. 6–27. Available at: http://www.cigre.org/Menu-links/.

Bashir, S. (2020) *COGATI Reforms*. Nexa Advisory, Melbourne. Nexa Advisory, Melbourne.

Billimoria, F. and Poudineh, R. (2019) 'Market design for resource adequacy: A reliability insurance overlay on energy-only electricity markets', *Utilities Policy*, 60(January), p. 100935.

Billimoria, F. and Simshauser, P. (2023) 'Contract design for storage in hybrid electricity markets', *Joule*, 7(8), pp. 1663–1674. Available at: https://doi.org/10.1016/j.joule.2023.07.002.

Bird, L. *et al.* (2016) 'Wind and solar energy curtailment: A review of international experience', *Renewable and Sustainable Energy Reviews*, 65, pp. 577–586.

Dodd, T. and Nelson, T. (2019) 'Trials and tribulations of market responses to climate change: Insight through the transformation of the Australian electricity market', *Australian Journal of Management*, 44(4), pp. 614–631.

Du, P. (2023) *Power Electronics and Power Systems Renewable Energy Integration for Bulk Power Systems ERCOT and the Texas Interconnection*. Springer. Available at: https://doi.org/doi.org/10.1007/978-3-031-28639-1.

Du, X. and Rubin, O.D. (2018) 'Transition and Integration of the ERCOT Market with the Competitive Renewable Energy Zones Project'. Available at: https://doi.org/10.5547/01956574.39.4.orub.

Edenhofer, O. *et al.* (2013) 'On the economics of renewable energy sources', *Energy Economics*, 40, pp. S12–S23. Available at: https://doi.org/10.1016/j.eneco.2013.09.015.

Eicke, A., Khanna, T. and Hirth, L. (2020) 'Locational Investment Signals: How to Steer the Siting of New Generation Capacity in Power Systems?', *The Energy Journal*, 41(1), pp. 281–304.

Felder, F. (2011) 'Examining Electricity Price Suppression Due to Renewable Investments', *The Electricity Journal*, 24(4), pp. 34–46. Available at: https://doi.org/10.1016/j.tej.2011.04.001.

Feldman, R. and Levinson, A. (2023) 'Renewable Portfolio Standards', *The Energy Journal*, 44(01). Available at: https://doi.org/10.5547/01956574.44.4.rfel.

Gilmore, J., Nelson, T. and Nolan, T. (2022) *Quantifying the risk of renewable energy droughts in Australia's National Electricity Market (NEM) using MERRA-2 weather data*. CAEEPR Working Paper 2022-06.

Gohdes, N., Simshauser, P. and Wilson, C. (2022) 'Renewable entry costs, project finance and the role of revenue quality in Australia's National Electricity Market', *Energy Economics*, 114. Available at: https://doi.org/10.1016/j.eneco.2022.106312.

Gohdes, N., Simshauser, P. and Wilson, C. (2023) 'Renewable investments, hybridised markets and the energy crisis: Optimising the CfD-merchant revenue mix', *Energy Economics*, 125, p. 106824. Available at: https://doi.org/10.1016/j.eneco.2023.106824.

Gowdy, J. (2022) *Wild Texas Wind*. Regen Insight Paper, UK. Regen Insight Paper, UK.

Grubb, M. and Newbery, D. (2018) 'UK electricity market reform and the energy transition: Emerging lessons', *Energy Journal*, 39(6), pp. 1–25.

Hadush, S., Buijs, P. and Belmans, R. (2011) 'Locational signals in electricity market design: Do they really matter?', *2011 8th International Conference on the European Energy Market, EEM 11*, (May), pp. 622–627.

Hardt, C. *et al.* (2021) 'Practical experience with mitigation of sub-synchronous control interaction in power systems with low system strength', *Cigre Engineering & Science*, 21(Jun), pp. 5–13. Available at: http://www.cigre.org/Menu-links/ .

Heptonstall, P.J. and R. J. K. Gross, (2020) 'A systematic review of the costs and impacts of integrating variable renewables into power grids'. *Nature Energy*, at https://doi.org/10.1038/s41560-020-00695-4

Hirth, L., Ueckerdt, F. and Edenhofer, O. (2016) 'Why wind is not coal: On the economics of electricity generation', *Energy Journal*, 37(3), pp. 1–27.

Johnson, E.P. and Oliver, M.E. (2019) 'Renewable Generation Capacity and Wholesale Electricity Price Variance', *The Energy Journal*, 40(01), pp. 143–168. Available at: https://doi.org/10.5547/01956574.40.5.ejoh.

Joos, M. and Staffell, I. (2018) 'Short-term integration costs of variable renewable energy: Wind curtailment and balancing in Britain and Germany', *Renewable and Sustainable Energy Reviews*, 86(March), pp. 45–65.

Joskow, P.L. (2022) 'From hierarchies to markets and partially back again in electricity: Responding to decarbonization and security of supply goals', *Journal of Institutional Economics*, 18(2), pp. 313–329. Available at: https://doi.org/10.1017/S1744137421000400.

Klobasa, M., J. Winkler, F. Sensfuss, and M. Ragwitz (2013). 'Market Integration of Renewable Electricity Generation—the German Market Premium Model'. *Energy & Environment* 24(1/2): 127–146. https://doi.org/10.1260/0958-305X.24.1-2.127

McConnell, D. *et al.* (2013) 'Retrospective modeling of the merit-order effect on wholesale electricity prices from distributed photovoltaic generation in the Australian National Electricity Market', *Energy Policy*, 58, pp. 17–27. Available at: https://doi.org/10.1016/j.enpol.2013.01.052.

McDonald, P. (2023) 'Locational and market value of Renewable Energy Zones in Queensland', *Economic Analysis and Policy*, 80, pp. 198–213. Available at: https://doi.org/10.1016/j.eap.2023.08.008.

Millstein, D. *et al.* (2021) 'Solar and wind grid system value in the United States: The effect of transmission congestion, generation profiles, and curtailment', *Joule*, 5(7), pp. 1749–1775. Available at: https://doi.org/10.1016/j.joule.2021.05.009.

Munoz, F.D. *et al.* (2017) 'Does risk aversion affect transmission and generation planning? A Western North America case study', *Energy Economics*, 64, pp. 213–225.

Munoz, F.D., Watson, J.P. and Hobbs, B.F. (2015) 'Optimizing Your Options: Extracting the Full Economic Value of Transmission When Planning Under Uncertainty', *Electricity Journal*, 28(5), pp. 26–38.

Nelson, T. *et al.* (2013) 'An analysis of Australia's large scale renewable energy target: Restoring market confidence', *Energy Policy*, 62, pp. 386–400.

Nelson, T., Orton, F. and Chappel, T. (2018) 'Decarbonisation and wholesale electricity market design', *Australian Journal of Agricultural and Resource Economics*, 62(4), pp. 654–675.

Newbery, D., (2018) 'Evaluating the case for supporting renewable electricity', *Energy Policy*, 120, 684–696. https://doi.org/10.1016/j.enpol.2018.05.029

Newbery, D. (2021) 'Energy Policy National Energy and Climate Plans for the island of Ireland: wind curtailment , interconnectors and storage', *Energy Policy* [Preprint], (February). Available at: https://doi.org/https://doi.org/10.1016/j.enpol.2021.112513.

Newbery, D. (2023a) 'Efficient Renewable Electricity Support: Designing an Incentive-compatible Support Scheme', *The Energy Journal*, 44(3). Available at: https://doi.org/10.5547/01956574.44.3.dnew.

Newbery, D. (2023b) 'High renewable electricity penetration: Marginal curtailment and market failure under "subsidy-free" entry', *Energy Economics*, 126, p. 107011. Available at: https://doi.org/10.1016/j.eneco.2023.107011.

Newbery, D. (2023c) *High renewable electricity penetration: marginal curtailment and market failure under 'subsidy-free' entry*. Available at: https://ssrn.com/abstract=4343013.

Nolan, T., Gilmore, J. and Munro, J. (2022) *The role of gas price in wholesale electricity price outcomes in the Australian National Electricity Market*. Centre for Applied Energy Economics and Policy Research, Working Paper 2022-03.

O'Shaughnessy, E., Cruce, J. and Xu, K. (2021) 'Rethinking solar PV contracts in a world of increasing curtailment risk', *Energy Economics*, 98. Available at: https://doi.org/10.1016/j.eneco.2021.105264.

Pollitt, M.G. and Anaya, K.L. (2016) 'Can current electricity markets cope with high shares of renewables? A comparison of approaches in Germany, the UK and the state of New York', *Energy Journal*, 37(Special Issue 2), pp. 69–88. Available at: https://doi.org/10.5547/01956574.37.SI2.mpol.

Qays, M.O. *et al.* (2023) 'System strength shortfall challenges for renewable energy-based power systems: A review', *Renewable and Sustainable Energy Reviews*, p. 113447. Available at: https://doi.org/10.1016/j.rser.2023.113447.

Rai, A. and Nelson, T. (2020) 'Australia's National Electricity Market after Twenty Years', *Australian Economic Review*, 53(2), pp. 165–182.

Rai, A. and Nelson, T. (2021) 'Financing costs and barriers to entry in Australia's electricity market', *Journal of Financial Economic Policy*, 13(6), pp. 730–754. Available at: https://doi.org/10.1108/JFEP-03-2020-0047.

Rystad Energy (2023) *Australia Renewables & Power Trends Report*.

Sauma, E.E. and Oren, S.S. (2006) 'Proactive planning and valuation of transmission investments in restructured electricity markets', *Journal of Regulatory Economics*, 30(3), pp. 261–290.

Seel, J. *et al.* (2023) *Interconnection Cost Analysis in the PJM Territory Interconnection costs have escalated as interconnection requests have grown*. Available at: https://emp.lbl.gov/interconnection_costs.

Sensfuß, F., Ragwitz, M. and Genoese, M. (2008) 'The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany', *Energy Policy*, 36(8), pp. 3086–3094.

Simshauser, P. (2020) 'Merchant renewables and the valuation of peaking plant in energy-only markets', *Energy Economics*, 91, p. 104888.

Simshauser, P. (2021) 'Renewable Energy Zones in Australia' s National Electricity Market', *Energy Economics*, 101(July), p. 105446.

Simshauser, P. and Gilmore, J. (2020) ‘On entry cost dynamics in Australia’s national electricity market’, *Energy Journal*, 41(1), pp. 259–287.

Simshauser, P. and Gilmore, J. (2022) ‘Climate change policy discontinuity & Australia’s 2016-2021 renewable investment supercycle’, *Energy Policy*, 160(August 2021), p. 112648. Available at: https://doi.org/10.1016/j.enpol.2021.112648.

Simshauser, P., Billimoria, F. and Rogers, C. (2022), ‘Optimising VRE capacity in Renewable Energy Zones’, *Energy Economics*, 113, p106239.

Simshauser, P., Nelson, T. and Gilmore, J. (2023) ‘The sunshine state: Cause and effects of mass rooftop solar PV take-up rates in Queensland’, in *The Future of Decentralized Electricity Distribution Networks*. Elsevier, pp. 49–79. Available at: https://doi.org/10.1016/B978-0-443-15591-8.00014-0.

Simshauser, P. and Wild, P. (2023) *Rooftop solar PV, coal plant inflexibility and the minimum load problem*. CAEEPR Working Paper 2023-04.

Tor, O.B., Guven, A.N. and Shahidehpour, M. (2008) ‘Congestion-driven transmission planning considering the impact of generator expansion’, *IEEE Transactions on Power Systems*, 23(2), pp. 781–789.

Wagner, J. (2019) ‘Grid investment and support schemes for renewable electricity generation’, *Energy Journal*, 40(2), pp. 195–220.

van der Weijde, A.H. and Hobbs, B.F. (2012) ‘The economics of planning electricity transmission to accommodate renewables: Using two-stage optimisation to evaluate flexibility and the cost of disregarding uncertainty’, *Energy Economics*, 34(6), pp. 2089–2101.

Appendix I: PF Model

In the PF Model, prices and costs increase annually by a forecast general inflation rate (CPI).

$$\pi_j^{R,C} = \left[1 + \left(\frac{CPI}{100}\right)\right]^j , \tag{1}$$

Energy output q_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs, fixed and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period *j*. Plant auxiliary losses Aux^i arising from on-site electrical loads are deducted. Plant output is measured at the Node and thus a Marginal Loss Factor MLF^i coefficient is applied.

$$q_j^i = CF_j^i . k^i . \left(1 - Aux^i\right). MLF^i, \tag{2}$$

A convergent electricity price for the *i*th plant $\left(p^{i\varepsilon}\right)$ is calculated in year one and escalated per eq. (1). Thus revenue for the *i*th plant in each period *j* is defined as follows:

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

If thermal plant are to be modelled, marginal running costs need to be defined per Eq. (4). The thermal efficiency for each generation technology ζ^i is defined. The constant term '3600'[12] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the *j*th period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{ \left[\left(\frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i \right) + \left(g^i . CP_j\right) \right] . q_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i\right) . \frac{\left(3600/\zeta^i\right)}{1000} \right\}, \tag{4}$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in \$/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i . k^i . \pi_j^C, \tag{5}$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the *j*th period can therefore be defined as follows:

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right), \tag{6}$$

[12] The derivation of the constant term 3,600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3,600 Joules.

Capital Costs $\left(X_0^i\right)$ for each plant *i* are Overnight Capital Costs and incurred in year 0. Ongoing capital spending $\left(x_j^i\right)$ for each period *j* is determined as the inflated annual assumed capital works program.

$$x_j^i = c_j^i . \pi_j^C , \tag{7}$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right), \tag{8}$$

From here, taxation payable $\left(\tau_j^i\right)$ at the corporate taxation rate (τ_c) is applied to $EBITDA_j^i$ less Interest on Loans $\left(I_j^i\right)$ later defined in (16), less d_j^i. To the extent $\left(\tau_j^i\right)$ results in non-positive outcome, tax losses $\left(L_j^i\right)$ are carried forward and offset against future periods.

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

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

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project financings. Debt structures available in the model include bullet facilities and semi-permanent amortising facilities (Term Loan B and Term Loan A, respectively).

Corporate Finance typically involves 5- and 7-year bond issues with an implied 'BBB' credit rating. Project Finance include a 5-year Bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an 18-25 year period (depending on the technology) and a second facility commencing with tenors of 5-12 years as an Amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years. The decision tree for the two Term Loans was the same, so for the Debt where DT = 1 or 2, the calculation is as follows:

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

D_0^i refers to the total amount of debt used in the project. The split (S) of the debt between each facility refers to the manner in which debt is apportioned to each Term Loan facility or Corporate Bond. In most model cases, 35% of debt is assigned to Term Loan B and the remainder to Term Loan A. Principal P_{j-1}^i refers to the amount of principal repayment for tranche *T* in period *j* and is calculated as an annuity:

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

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Term Loan or Corporate Bond. The relevant interest payment in the *j*th period (I_j^i) is calculated as the product of the (fixed) interest rate on the loan or Bond by the amount of loan outstanding:

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

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the *i*th plant is calculated as the sum of the above components for the two debt facilities in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (as per eq.11). This is determined by the product of the gearing level and the Overnight Capital Cost (X_0^i). Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing 'BBB' rated bonds) and Independent Power Producers using Project Finance (PF).

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

Credit metrics[13] (δ_j^{VI}) and (ω_j^{VI}) are exogenously determined by credit rating agencies and are outlined in Table 2. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

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

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

[13] For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

$$0 = -X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1 + K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1 + K_e)^{-(j)} - D_0^i \qquad (16)$$

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

Let $IRR \equiv K_e$

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

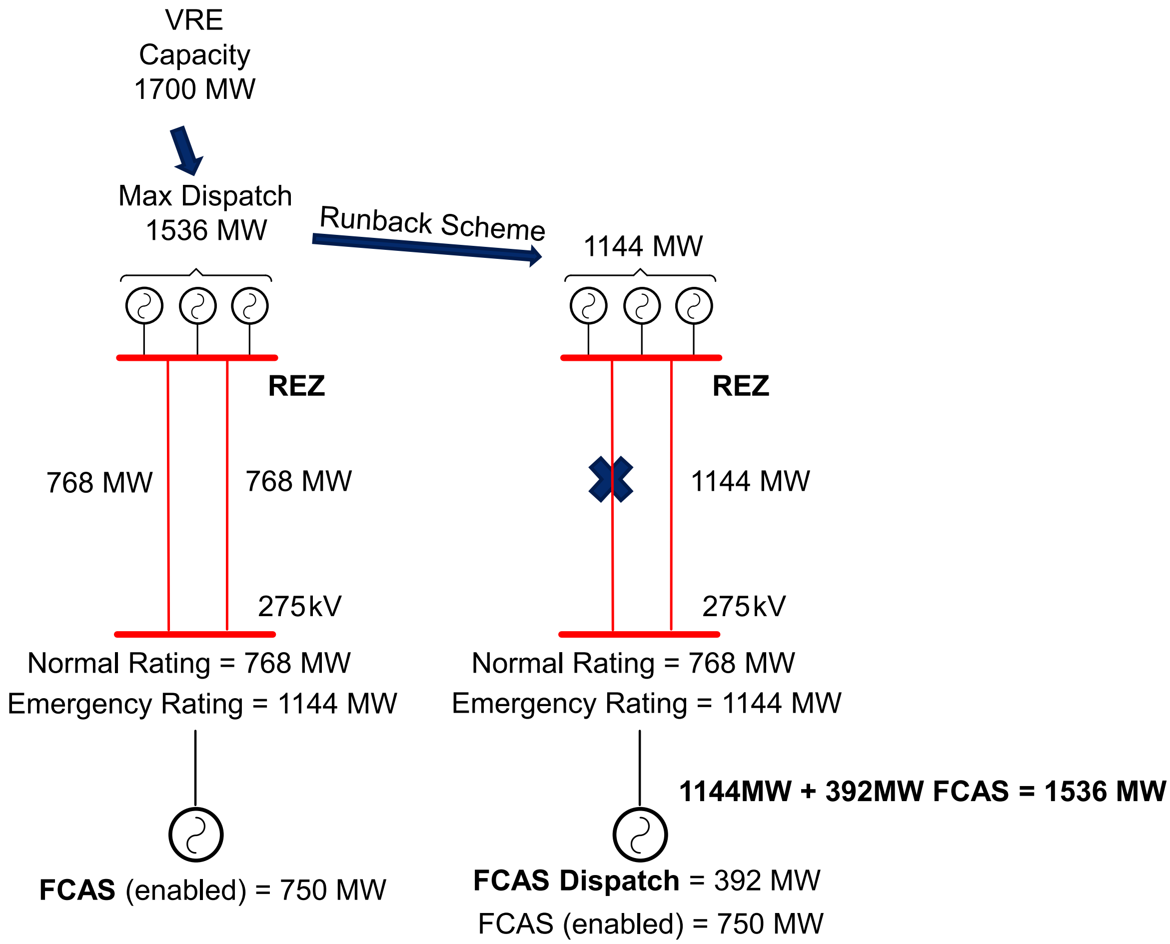
The model then solves for $p^{i\varepsilon}$ such that:

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

Appendix II: REZ Optimisation Model – Line Ratings

Consider the double circuit 275kV radial REZ in which 1700MW of renewable plant capacity has been connected at three locations. Maximum power flows were defined by Eq. (1) (see Section 3) and are illustrated in Fig. A1. Note on the LHS of Fig. A1 where both circuits are in service, maximum power flows in summer are constrained to 1,536MW. Specifically, both conductors are capable of operating 768MW each, or 1,536MW in aggregate per Eq. (1).

Figure A1 - Double circuit 275kV credible transfer capacity – summer



The RHS of Fig. A1 illustrates how transfer capacity is limited following the credible loss of a circuit (e.g. lightening strike). Following the loss of a single circuit, the system must adjust instantaneously using a ‘post contingent’ runback scheme. This is clearly illustrated on the RHS of Fig. A1. The three connected generators are constrained to 1,144MW (i.e. under the runback scheme). This constraint is bounded by the emergency summer rating the remaining conductor in-service, at 1,144MW.

Simultaneously, the system operator’s FCAS suite of 750MW (enabled) will be called upon in real-time for 3,92MW of power to rebalance the system (i.e. 1,144 MW + 392 MW FCAS = pre-contingent output of 1,536 MW = 2 x 768MW).