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Competition vs. Coordination: Optimising Wind, Solar and Batteries in Renewable Energy Zones

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Abstract

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Keywords *Renewable Energy Zones, Renewables, Spilled Energy, Marginal Curtailment, Battery Storage*

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

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Decarbonising Australia's power system requires high market shares of variable renewable energy. An important policy initiative to achieve this is the establishment of Renewable Energy Zones (REZs). As renewable market share increases, spilled energy within REZs is predictable. Spilled energy occurs due to high peak-to-average output ratios of intermittent renewables (being ~3:1), largely inelastic aggregate final electricity demand, and the economic limits of REZ network transfer capacity. In an open access, multi-zonal market setup, an intuitive response by policymakers may be to undertake connection reform (i.e. priority access) and underwrite storage assets to alleviate the worst effects of spilled energy. Prima facie, spilled energy and lines congestion may be reduced, and wind and solar capacity increased, through the deployment of battery storage. However, as model results in this article reveal, priority access makes multi-zonal markets more sensitive to spilled energy, and competitive batteries within a REZ aggravates congestion. Further, early entrant batteries may oversize their MW capacity and crowd-out renewables. All these cases harm welfare within a REZ. Optimally sized coordinated 'portfolio' batteries alleviate congestion because they don't compete for scarce REZ transfer capacity. Rival batteries should be located outside REZs.

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1. Introduction

Renewable Energy Zones or 'REZs' have become a key policy initiative of the State Governments that comprise Australia's National Electricity Market (NEM). Stylised on the Texas / ERCOT Competitive REZs, they are a means by which to create the necessary network hosting capacity needed to increase renewable market share and better coordinate decentralised generation investments (Doshi and Du, 2020; Jang, 2020). Two or three rival and sequentially located renewable investors, acting independently, may trigger multiple network augmentations to the transmission backbone. By contrast, a REZ entails a single set of connection assets traversing sequentially located projects. REZs may therefore avoid needless network duplication, minimise community impacts, and by connecting multiple sequential renewable proponents, better utilise shared assets and lower total connection costs.

In the NEM's Queensland region, REZs are developed by the transmission utility under a semi-merchant model where user charges are levied on the connecting generators.

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Development of renewable energy projects is notoriously difficult, and multiple projects simultaneously reaching financial close could only happen by chance. Accordingly, and under the right conditions, the transmission utility will *'salami slice'* REZ user charges across anchor- and latter-entrant projects to minimise renewable plant entry costs (Simshauser, 2021). Under this approach, the transmission utility warehouses some level of (ex ante transient) idle REZ transmission capacity to provide the necessary time for multiple projects to reach financial close. Understandably, both renewable developers and consumer groups support the model – with the latter especially supportive given the REZ transmission assets don't 'default' into the consumer-funded Regulatory Asset Base.

In a deregulated market such as the NEM, renewable generators operate in an intensely competitive environment. REZ assets and associated user charges must therefore be optimised to ensure minimum cost is achieved. Sizing transmission investments is a straightforward process once potential renewable projects, quality of renewable investors, renewable resource complementarity, and the nature of the *peak-to-average output ratio* of renewable output are understood.

This latter concept, the *peak-to-average ratio* of renewable output, is a crucial one. As Newbery explains in his numerous articles on the topic[1], a 100MW solar farm can be expected to reach its maximum output on a regular basis, but average output over the year might be just 25MW. It thus has a peak-to-average output ratio of ~4:1. Wind projects typically exhibit peak-to-average output ratios of ~3:1. The NEM's renewable generators are therefore very different to the base load coal plants they are replacing. High peak-to-average output ratios makes unconstrained network access for renewables particularly inefficient. To generalise, minimum system cost necessitates that REZs be purposefully oversubscribed with wind and solar PV plant capacity – meaning some level of curtailment is inevitable, efficient and therefore desirable.

Well before the optimal levels of Variable Renewable Energy (VRE) plant capacity enter a REZ, some level of 'spilled energy' or congestion-driven curtailment arises. And as entry continues and the fleet-wide average rate of curtailment rises, the Annual Capacity Factor of renewable projects within the REZ begins to fall – and will ultimately reach a tipping point of *"bankability"*. Critically, the marginal rate of curtailment arising from transmission line congestion will rise at 3-4 times the average rate of curtailment (Newbery and Biggar, 2024; Simshauser and Newbery, 2024). This means the final MW of wind capacity installed in a congested REZ may produce as little as 40% of the first MW of wind capacity installed. The implication of these dynamics for (i) transmission access policy, and (ii) the role of storage, is material.

The purpose of this article is to identify the process for identifying the optimal mix of complementary VRE plant capacity in a REZ under two different access regimes, with and without battery storage in a multi-zonal electricity market setup. While optimising complementary REZ plant capacity has previously been examined (Simshauser et al., 2022; Simshauser, 2024b; Simshauser and Newbery, 2024) – this prior research excluded the impact of battery storage. This article aims to fill that gap.

Battery investment commitments in Australia's NEM, and in the Queensland region, are surging (see Tab.1). At the time of writing, almost 1800MW of batteries across 30 sites were operational, with a further 26 projects at financial close or under construction, taking the total to more than 8000 MW (with a further 10,947MW approved for development) in a 35GW system. In the Queensland region, 2000+MW have reached

[1] See Newbery (2021, 2023c, 2023b)

irreversible commitment and interestingly, none have been underwritten by government-initiated CfDs – each battery entered by way of bilateral, on-market transaction.

Underpinning NEM battery entry are market dynamics associated with a 'solar-rich' power system, combined with largely inelastic aggregate final electricity demand and inflexible baseload plant. Collectively these characteristics have produced some of the highest intra-day price spreads across the worlds' major electricity markets over the period 2021-2024 (i.e. negative price events during the day for charging, and evening price spikes during post-solar periods for dispatch).[2]

Table 1: Battery storage projects (NEM and Queensland region)

NEM	Count	Capacity (MW)	Storage (MWh)	Duration (Hrs)
Operating	30	1,767	2,671	1.5
Construction	22	5,233	12,663	2.4
Financial Close	4	1,340	5,910	4.4
Committed	56	8,340	21,244	2.5
Approved	41	10,947	47,823	4.4
QLD				
Operating	8	437	818	1.9
Construction	7	1,655	4,510	2.7
Financial Close	0	-	-	-
Committed	15	2,092	5,328	2.5
Approved	21	7,260	39,900	5.5

Source: Rystad Energy, Powerlink.

Given the extraordinary level of investor interest in battery storage, it is appropriate to explore the welfare implications of battery additions *within a REZ* under varying access arrangements (open vs. priority) and industrial organisation (coordination vs. competition). For this purpose, the REZ Optimisation Model from Simshauser and Newbery (2024) has been modified, thus drawing on renewable resources and market data from the NEM's Queensland region.

REZ Optimisation Model analyses of access arrangements and industrial organisation reveal striking results. To summarise these, Queensland wind and solar are complementary resources, and so a ~1500MW transmission line will host vastly more installed wind and solar capacity than 1500MW. The outer-bound of *"bankable"* complementary VRE capacity will be regulated by capital markets and their *tolerance* for curtailment. Second, in a multi-zonal market setup, open access (cf. priority access with physical access rights to the edge of the REZ) proves welfare enhancing because of peak-to-average output ratios of VRE plant. And finally, and perhaps *prima facie* counterintuitively, competitive battery entrants or oversized early-entrant batteries *within a REZ* harm welfare in deregulated markets. Rival batteries compete for scarce REZ network access and crowd-out VRE entry, thereby damaging productivity. Conversely, a coordinated *portfolio battery* within a REZ in an open access regime increases productivity.

[2] Rystad Energy recently analysed 39 international electricity markets (2021-2024) and the NEM regions of Queensland, South Australia and New South Wales consistently exhibited (by far) the highest intraday spreads.

This article is structured as follows. Section 2 provides a brief review of literature. Section 3 introduces the REZ Optimisation Model and associated data. Section 4 presents model results. Policy implications and concluding remarks follow.

2. Review of Literature

Progressively adding VRE plant capacity to a power system introduces different challenges as the market share of intermittent plant rises. In the early deployment phase (during the 2000s), scale and cost were the main problems to be solved. These were overcome by policy priming, viz. renewable portfolio standards and certificated schemes, centrally auctioned Contracts-for-Differences, and Feed-in Tariffs (see variously Buckman and Diesendorf, 2010; Nelson et al., 2013; Schelly, 2014; Nelson, 2015; Nelson et al., 2022; Newbery, 2023b, 2023a).

When VRE market share further increased to ~20% (during the 2010s), merit order effects were revealed. Merit order effects were accompanied by rising episodes of negative prices (Sensfuß et al., 2008; Felder, 2011; Forrest and MacGill, 2013; McConnell et al., 2013; Cludius et al., 2014; Antweiler and Muesgens, 2021).

International dynamics arising from multilateral agreements (e.g. Paris Agreement), jurisdictional policy initiatives (e.g. Inflation Reduction Act) and global energy shocks (e.g. Russia-Ukraine War) led to rapidly surging investment in renewables (Nelson, 2020; Simshauser and Gilmore, 2022; Fabra, 2023; Pollitt, 2023). In certain power systems, VRE plant capacity rising beyond ~30% led to a third wave of challenges – those associated with system strength shortfalls (Badrzadeh *et al.*, 2020; Hardt *et al.*, 2021; Qays *et al.*, 2023), deteriorating inertia (Newbery, 2021), falling minimum loads (Billimoria and Poudineh, 2019; Billimoria and Simshauser, 2023; Simshauser and Wild, 2024) and in some instances, disorderly thermal plant exit (Nelson, 2018; Nelson et al., 2018; Dodd and Nelson, 2019; Rai and Nelson, 2021; Flottmann, 2024).

Holding all else constant, rising levels of VRE will be accompanied by ever-increasing curtailment rates. As noted above, this is driven by the *peak-to-average output ratios* of VRE (Newbery, 2021, 2023b, 2023a, 2023c; Newbery and Biggar, 2024). The synchronicity of a large wind fleet, and of solar PV, results in spilled production or *curtailment*, which arises from two distinct sources:

(i) *production curtailment* due to network congestion, where localised aggregate VRE output exceeds the transfer limits of the transmission network (McDonald, 2023, 2024); and

(ii) *economic curtailment* due to market imbalances, which occurs when aggregate VRE output exceeds inelastic aggregate final electricity demand (Newbery, 2023b), signalled by negative spot price events (Rai and Nunn, 2020).

Within industry circles, it is broadly accepted that one of the key constraints to VRE development is the adequacy of network hosting capacity (Kim *et al.*, 2023; Simshauser, 2024). Rising levels of production curtailment amongst renewable producers signals an increasingly constrained power system, at which point capital markets will begin to regulate new investment (Gowdy, 2022; Gohdes, 2023; Gohdes et al., 2023; Simshauser and Newbery, 2024). If the cause of curtailment is rising network congestion, it is not until additional network hosting capacity arrives that further VRE investment is possible. One of the earliest observations of this cycle occurred in the Texas // ERCOT market (see Jang, 2020; Gowdy, 2022; Du, 2023). Renewable investment cycles were visibly apparent either-side of ‘anticipatory investments’ in ERCOT’s Competitive REZ (Du and Rubin, 2018). Conversely, battery storage may be capable of alleviating some level of *economic curtailment* (Billimoria and Simshauser, 2023).

REZs have become an important policy initiative in Australia’s NEM (McDonald, 2024; Simshauser, 2024). By definition, REZs involve network augmentations adjacent to the existing transmission backbone to connect multiple VRE proponents that may otherwise act, and connect, independently (Simshauser, 2021; McDonald, 2023; Newbery and Biggar, 2024). In theory at least, REZ should have the effect of minimising the risk of duplicate network investments and falling network productivity (Simshauser, Billimoria and Rogers, 2022; McDonald, 2024). However, such outcomes are contingent upon some level of risk taking by a benevolent network planner (Simshauser, 2021), exploiting the complementarity of renewable resources (McDonald, 2023) and ensuring the access regime maximises welfare (Simshauser and Newbery, 2024). Intuitively, adding storage to a REZ should enhance the productivity and efficiency of a REZ (Newbery, 2018, 2023c; Billimoria and Simshauser, 2023) by reducing the worst economic effects of curtailment. But as subsequent modelling in Section 4 reveals, the prevailing transmission access regime, and the timing and industrial form of battery entrants is vitally important.

3. REZ Data and Models

The modelling suite that follows draws directly from Simshauser & Newbery (2024) and extends this prior research by including multiple equilibria and battery storage. Full details are set out below but to summarise, modelling commences with a Project Finance Model to derive commercial wind, solar and battery plant costs. A REZ Optimisation Model then identifies the optimal investment mix (planning timeframes) and dispatch (operational timeframes) of VRE and battery storage. Historic hourly weather, matched to hourly NEM spot price data over a five-year period 2017-2021, forms the backdrop. Spot prices are dynamically adjusted vis-a-vis merit order effects by drawing on the work of Gonçalves and Menezes (2022), resulting in a rich set of investment outcomes in equilibrium (thus necessitating simulation iterations).

3.1 Entry Costs of Wind, Solar PV and Battery Storage

The ‘PF Model’ is a conventional multi-period project and corporate finance program capable of simulating multiple generation technologies under a range of organisational structures and structured financing options. The PF Model produces generalised post-tax, post-financing Levelized Cost of Electricity estimates where structured finance and taxation variables are co-optimised endogenously. Inputs appear in Tables 2-3 and are consistent with Gohdes et al., (2022, 2023).

Table 2: PF Model parameters (pre-connection costs)

	Plant Parameters		Wind	Solar	Storage
1	Capacity Cost	($/kW)	2,800	1,600	547
2	Storage Cost	($/kWh)			450
3	Annual Capacity Factor	(%)	35.0	26.5	n/a
4	Cycles per day		n/a	n/a	1
5	Curtailment Limit	(%)	5.0	8.0	n/a
6	Auxillary Load	(%)	1.0	1.0	1.0
7	Transmission Losses	(MLF)	0.98	0.97	0.98
8	Fixed O&M	($/MW/a)	29,940	20,000	10,000
9	Variable O&M		0	0	Eq.8-9*
10	Ancillary Services**	(% Rev)	-1%	-1%	30%
11	Operating Life	(Yrs)	35	25	20
	*Eq.8-9 appear in Section 3.4				

Source: Gohdes (2022, 2023).

Project financings are split into 5-year Bullet (Term Loan 'B') and 7-year Amortising (Term Loan 'A') facilities – shorter dated (5-7 year) debt being the dominant tenor currently used in Australia's NEM.

Table 3: PF Model parameters (financial)

Renewable Project Finance		
Debt Sizing Constraints		
- DSCR	(times)	1.25
- Gearing Limit	(%)	82.5%
- Default	(times)	1.05
Project Finance Facilities - Tenor		
- Term Loan B (Bullet)	(Yrs)	5
- Term Loan A (Amortising)	(Yrs)	7
- Notional amortisation	(Yrs)	18
Project Finance Facilities - Pricing		
- Term Loan B Swap	(%)	4.12%
- Term Loan B Spread	(bps)	180
- Term Loan A Swap	(%)	4.23%
- Term Loan A Spread	(bps)	209
- Refinancing Rate	(%)	6.2%
Expected Equity Returns	(%)	8.0%

Source: Gohdes (2022, 2023), Bloomberg.

As the model logic is set out in considerable detail in Appendix I of Simshauser (2024), it is not reproduced here. Critical PF Model outputs used in subsequent REZ Optimisation Modelling are as follows:

- Entry Cost of Wind — $93/MWh (incl. REZ user charges, ACF = 35%)
- Entry Cost of Solar PV — $68/MWh (incl. REZ user charges, ACF = 26.5%)
- Entry Cost of Batteries[3] — $11.0/MW/h for the 1st hour storage; $4.5/MW/h for each subsequent hour of storage

3.2 Overview of REZ Optimisation Model setup

The REZ Optimisation Model setup is structured as a Stackelberg game along similar lines to Hassanzadeh Moghimi et al., (2024). A benevolent welfare maximising

[3] These represent the "carrying cost" of the battery. To determining the annual fixed and sunk costs of a 200MW, 400MWh battery is therefore as follows: ($11 + $4.5) x 200 x 8760hrs = $27.2 million pa.

transmission utility forms the leader. Renewable developers are followers. In the upper level, the transmission utility endogenously determines the REZ network capacity and user charges. In the lower-level, Nash-Cournot games amongst profit-maximising renewable developers occur over two timeframes. First, *competition for the market* occurs in planning timeframes (i.e. plant investment commitments). Second, *competition in the market* occurs in operational timeframes (i.e. dynamic dispatch, hourly resolution, five-year period). Investment commitment and subsequent dispatch of the VRE and storage fleet is assessed under two transmission access regimes in a multi-zonal market setup:

1. Non-firm 'open access' (the NEM's current format); and

2. 'priority access' (involving REZ access rights).

As subsequent modelling reveals, the welfare implications of these opposing access regimes are material (see also Simshauser and Newbery, 2024). In all scenarios, REZ transmission infrastructure is assumed to be *merchant,* meaning committed entrants are liable for REZ user charges. The transmission planner seeks to optimise plant connections for a given access regime, bounded by REZ network capacity limits and *tolerable* VRE curtailment rates. Tolerable curtailment rates mean they must be *"bankable"* – the levels of which are set by risk averse project banks and equity investors (Gohdes, 2023; Gohdes et al., 2023). *Bankable* curtailment rates are set exogenously in, and managed within, the REZ Optimisation Model with $'wind \ngtr 5\%\ lost\ production'$ and $'solar\ PV \ngtr 8\%\ lost\ production'$.

VRE plant are exposed to negative price events, which drives *economic curtailment.* As noted earlier, this is a separate category of production losses and is inherently uncertain, ex ante. To illustrate the cumulative effect of curtailment, using wind with an ex-ante 35% Annual Capacity Factor as a simple example, is as follows:

Potential Wind Output = 35.0% ACF

Less curtailment from congestion $(\ngtr 5\%\ production\ losses\ or\ 1.8\%\ ACF)$

Practical Wind Output = 33.2% ACF

Less economic curtailment, negative prices $(e.g.\ 0.2\%\ lost\ production)$

Economic Wind Output = 33.0% ACF

Scenarios will examine, and isolate, impacts of battery storage under distinctly different industrial organisation involving 'rival entrants', and (non-rivalrous) 'co-ordinated portfolio entrants'. For batteries operating inside a REZ, it is worth noting that the NEM comprises a multi-zonal market (i.e. five imperfectly interconnected zones or 'regions') along with locational Marginal Loss Factor coefficients by substation (static, revised annually) which essentially operate as a spot price multiplier. The implication of zonal prices for batteries by industrial organisation is as follows:

- A 'rival battery' operating inside a REZ faces the zonal spot price, and will therefore seek to maximise the daily arbitrage spread between charging and discharging activities by strictly observing the zonal spot prices. Rival batteries will compete for network access as real-time renewable output approaches the limits of REZ transmission line transfer capacity.

- A coordinated 'portfolio battery' operating inside a REZ will also seek to maximise the daily arbitrage spread. However, such a battery has the opportunity to charge at an implied 'zero price' if the portfolio wind (or solar) project is experiencing curtailment. The portfolio owner may curtail battery output and avoid competing for network access as real-time renewable output approaches the the limits of REZ transmission line transfer caapcity. The reason underlying these additional charging opportunities and additional discharging constraints in the zonal market setup is due to market convention in Australia's NEM, that is, all renewable Power Purchase Agreements are 'run of plant' (meaning spilled renewable output has a zero value).

3.3 Wind and solar data

The specific area (and weather data) being modelled is the Western Downs REZ in the NEM's Queensland region (Fig.1). The diurnal pattern of VRE on Queensland's Western Downs exhibits a level of complementarity, with average wind output rising either side of solar PV output (see Fig.2). Seasonal average correlation of wind and solar ranges from -0.75 in spring to -0.69 in winter. It is this complementarity which helps explain the intuition behind subsequent quantitative results, viz. *a priori* expectation that combined VRE plant capacity will exceed REZ transmission line transfer limits. However, hourly weather data exhibits much greater variability than seasonal averages (with the correlation reducing to -0.28) meaning high-resolution modelling is required to identify the true extent of portfolio diversity, and consequential impacts of energy storage.

Figure 1: Renewable Energy Zones in Queensland

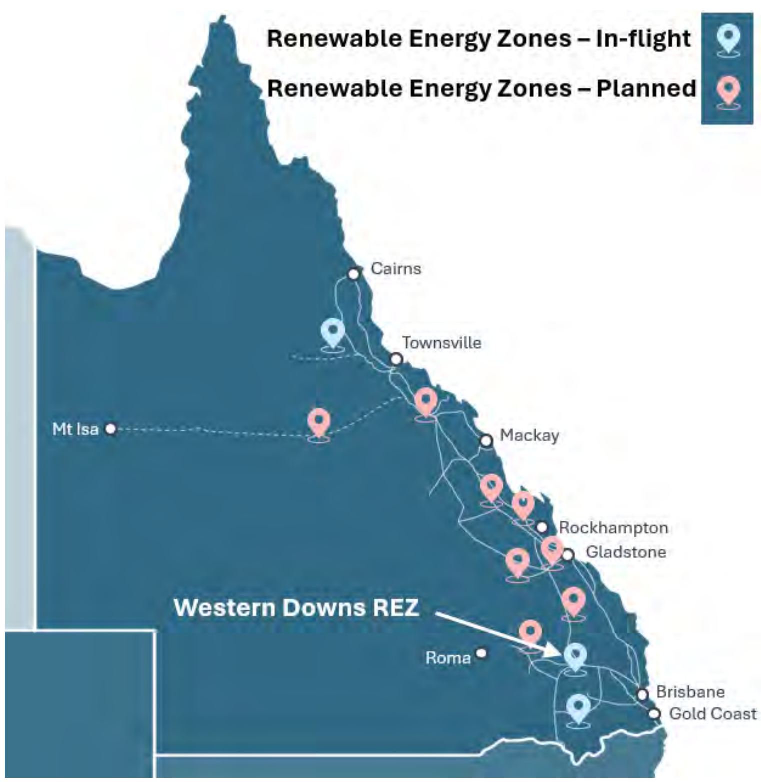
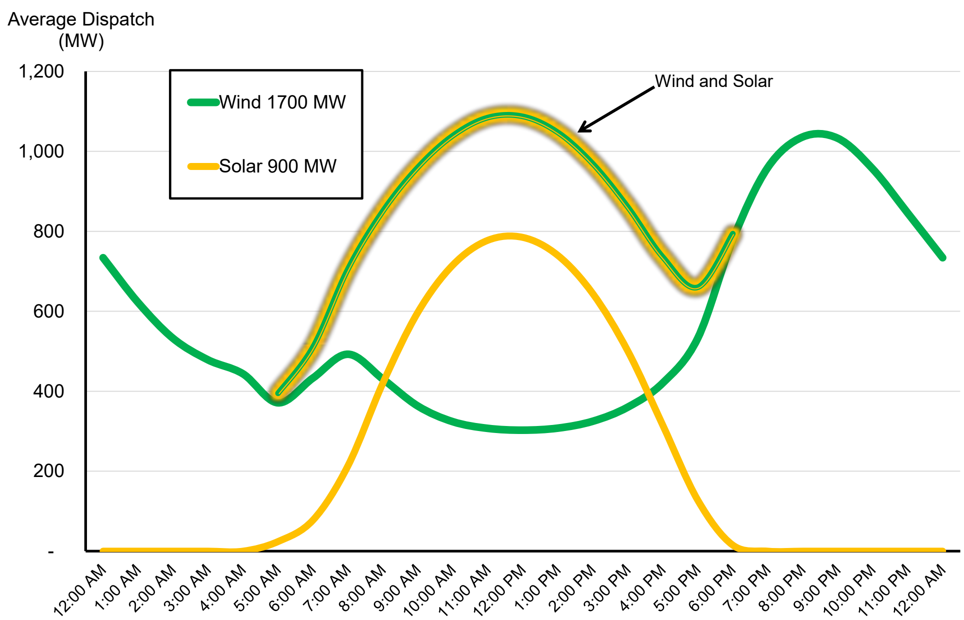


Figure 2: Average Summer Wind and Solar PV output (Western Downs)



The REZ Optimisation Model seeks to identify the optimal mix of VRE plant capacity given Western Downs renewable resource options, specified network transfer capacity, and five years of historic hourly weather reanalysis from 2017-2021 (drawn from Gilmore et al., 2022). A statistical summary of the appropriately matched spot price data over the same period appears in Tab.4, including the time-weighted average (Line 1) and selected statistics (Lines 2-13).

Table 4: Statistical summary of spot prices and dispatch-weighted prices (2023$)

	Spot Prices		2017	2018	2019	2020	2021	Total
1	Time Weighted Average	($/MWh)	126.8	90.9	85.9	48.5	104.2	91.2
2	Wind Dispatch Weighted	($/MWh)	120.6	92.9	89.3	51.9	107.2	92.4
3	Wind % of Average Spot	(%)	95%	102%	104%	107%	103%	101%
4	Solar Dispatch Weighted	($/MWh)	136.9	87.6	78.7	44.7	68.0	85.0
5	Solar % of Average Spot	(%)	108%	96%	92%	92%	65%	93%
6	95th Percentile Price	($/MWh)						
7	Standard Deviation	($/MWh)	360	47	54	59	435	257
8	Negative Price Events	(Hrs)	13	14	129	333	507	996
9	Coefficient of Variation		2.8	0.5	0.6	1.2	4.2	2.8
10	Kurtosis	($/MWh)	634	358	532	309	636	1,543
11	Skewness	($/MWh)	23	14	10	14	22	34
12	Minimum Spot Price	($/MWh)	-217	-174	-805	-641	-1,000	-1,000
13	Maximum Spot Price	($/MWh)	13,145	1,566	2,563	1,499	16,600	16,600

Source: Australian Energy Market Operator.

Optimisations introduce differing levels of wind and solar plant capacity, and this implies variations arising from merit order effects. Consequently, use of historic spot prices needs to be adjusted. As Bushnell and Novan (2021) and Gonçalves and Menezes (2022) show in the case of California and Australia respectively, variations in wind and solar PV plant capacity impact hourly prices differentially – both downwards (renewables on) and upwards (renewables off). Accordingly, and consistent with the modelling approach in Simshauser and Newbery (2024), the REZ Optimisation Model internalises the hourly wind and solar PV regression coefficients from Gonçalves and Menezes (2022), which in turn allows the model to dynamically adjust prevailing spot prices as VRE capacity levels are varied, noting that, for example, more solar has a price impressing effect during daylight hours, and an inverse effect during non-solar hours. The coefficients appear in Appendix I.

3.4 Structure of the REZ Optimisation Model

REZ Optimisation comprises a structural LP Model, commencing with a double circuit 275kV radial connection on Queensland's Western Downs linking back to the transmission backbone (Fig.1). The radial REZ network comprises multiple generator connection points. REZ transfer limits are driven by conductor type, allowable operating temperatures with normal seasonal[4] line ratings (~200km from Australia's coastline). Seasonal transfer limits, capital cost and annual users charges are as follows:

Table 5: Double Circuit 275kV REZ, Seasonal Transfer Limits and Costs

	Normal Rating (MW)
Summer	1536
Autumn/Spring	1756
Winter	1916
REZ Capital Costs	$450 million
REZ User Charges	$45 million pa

The REZ Optimisation Model seeks to maximise either aggregate output or profit, subject to a series of nominated constraints as set out below. The model is grounded firmly in welfare economics with optimisations measuring changes in consumer and producer surplus:

[4] While the REZ Optimisation Model also contains the data and equations to derive dynamic line ratings.

Let $g \in G$ be the set of potential generators, each with installed capacity K_g, connecting to the REZ which has seasonal line ratings REZ^s. Let $C_{g,t}$ be the perfectly divisible unit cost of each generation technology at any scale ($/MWh) as derived by the PF Model. Let $t \in T$ be the set of hourly dispatch intervals with plant availability in period t being $\beta_{g,t}$. Let $q_{g,t}$ be the output of generator g in trading interval t with the relevant spot price received for output being p_t. At this point, the objective function for maximising welfare becomes a relatively straight-forward one:

$$OBJ_W = Max\left(\sum_{t\in T}\sum_{g\in G} q_{g,t}\right), \tag{1}$$

S.T.

$$\sum_{g\in G} q_{g,t} \leq K_g \cdot \beta_{g,t}\ \forall\ g \in G, t \in T, \tag{2}$$

$$\sum_{g\in G} q_{g,t} \leq REZ_t^s\ \forall\ t \in T, \tag{3}$$

$$\left(\sum_{t\in T}\sum_{g\in G} q_{g,t}\right) \geq \left[\sum_{t\in T}\sum_{g\in G}\left(1-\delta_g\right)\cdot e\left(q_{g,t}\right)\right], \tag{4}$$

$$\left(\sum_{t\in T}\sum_{g\in G} q_{g,t}\cdot p_{g,t}\right) - \left(\sum_{t\in T}\sum_{g\in G} K_g \cdot C_{g,t}\right) \geq 0. \tag{5}$$

Eq.(1) sets the Objective Function for maximising Production. Eq.(2) limits generation dispatch to available capacity $K_g \cdot \beta_{g,t}$. Eq. (3) constrains total generation in each dispatch interval $t \in T$ to the seasonal transmission line flow limits of the Renewable Energy Zone REZ_t^s in accordance Tab.3. Eq.(4) ensures wind and solar curtailment $\left(\delta_g\right)$ impacting expected output $e\left(q_{g,t}\right)$ of the optimised VRE fleet does not exceed exogenously determined *bankability limits* associated with contemporary project financings. And Eq.(5) ensures all production maximising solutions achieve a normal return, with revenue derived by production output $q_{g,t}$ at the relevant spot price $p_{g,t}$ with a level of normal profit being determined when entry costs of plant, $C_{g,t}$, equal revenues. Any level above this represents supranormal profits, since entry costs arising from the PF Model include normal returns to equity. The objective function for profit maximising scenarios (OBJ_{EP}) is similarly straight forward:

$$OBJ_{EP} = Max\ \left[\left(\sum_{t\in T}\sum_{g\in G} q_{g,t}\cdot p_{g,t}\right) - \left(\sum_{t\in T}\sum_{g\in G} K_g \cdot C_{g,t}\right)\right], \tag{6}$$

S.T.
Eq.(2-4).

In specific scenarios, battery storage is made available to form part of the potential fleet of REZ-connected generators $g \in G$. As noted above, batteries may be *'competitive rivals'* within the REZ, or may form part of a *'coordinated portfolio'* of VRE assets. Regardless of whether the model seeks to maximise production (Eq.1) or profit (Eq.6), *rival batteries* always seek to maximise arbitrage profit each day (Arb_d) for any given level of storage, n at prevailing zonal prices. Batteries achieve this by discharging $\left(p_{g,t}\right)$ during the maximum daily spot price events $(Smax_t)$, and recharging $\left(-p_{g,t}\right)$ during minimum daily spot price events $(Smin_t)$, and are strictly limited to one cycle per day.

$$Arb_d = \sum_{t=1}^{n} Smax_t \cdot p_{g,t} \sum_{t=1}^{n} Smin_t \cdot -p_{g,t} \tag{7}$$

Charging and dispatch of coordinated portfolio batteries is subtly different. In any trading interval where aggregate VRE output $q_{g,t}$ is expected to exceed REZ_t^s seasonal transmission line ratings, the prevailing zonal spot price (p_t) is deemed to be zero at the local (i.e. locational) level $(\hat{p}_t = 0)$ such that:

$$Arb_d = \left(\sum_{t=1}^{n} \hat{p}max_t \cdot q_{g,t} \sum_{t=1}^{n} \hat{p}min_t \cdot -q_{g,t} \middle| if \begin{cases} q_{g,t} \geq REZ_t^s, \hat{p}_t = 0 \\ q_{g,t} \geq REZ_t^s, \hat{p}_t = p_t \end{cases} \right) \tag{8}$$

The point of distinction between Eq.(7) and Eq.(8) is:

- *rival batteries* via Eq.(7) maximise profit given prevailing zonal spot prices p_t;
- *portfolio batteries* via Eq.(8) treat transmission line congestion events as an opportunity to recharge at a 'deemed' local zero price[5], and adjust output to work around wind and solar PV dispatch.

4. Model Results

The objective of the modelling suite is to identify the optimal mix of wind and solar resources under two distinct access arrangements (open vs. priority) with three states of storage (i.e. no storage, competitive 'rival' storage, coordinated 'portfolio' storage).

4.1 'Average Curtailment' versus 'Marginal Curtailment'

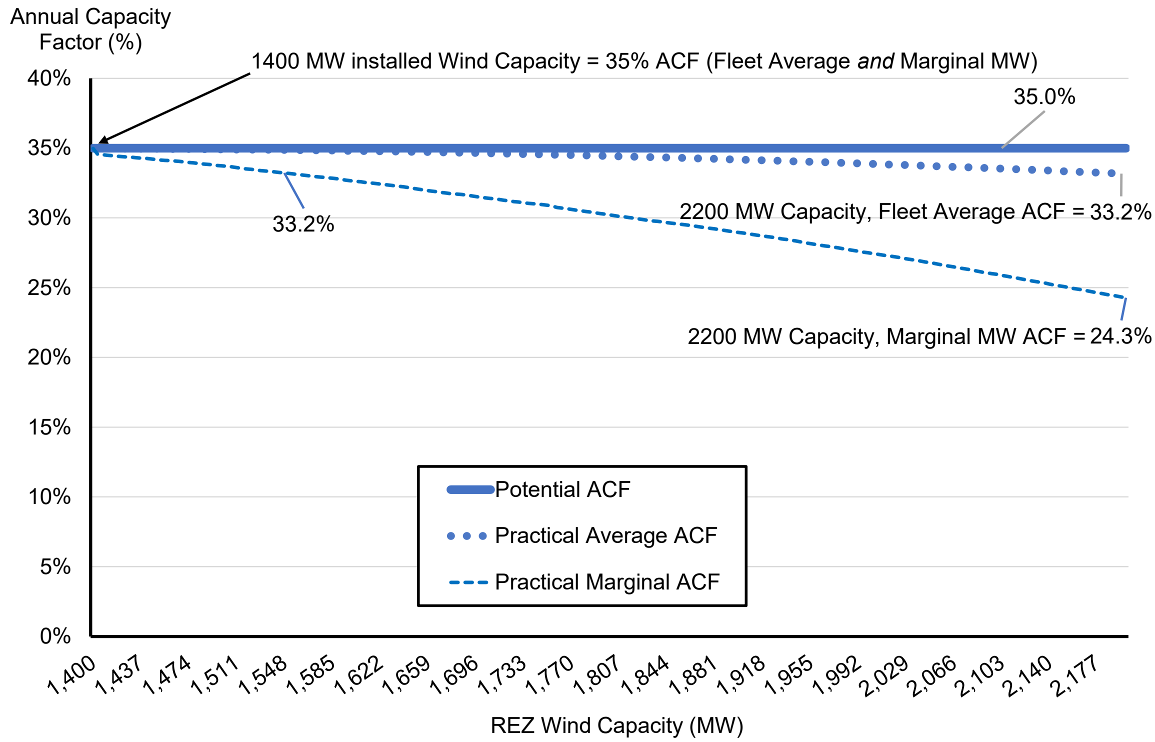
Given the NEM's multi-zonal market setup and open access regime, new plant commitments within a REZ are fundamentally exposed to *average rates of curtailment*. If access in the NEM was changed to 'priority access' as has been proposed from time to time, new entrant plant would face *marginal rates of curtailment*. These two terms – the *average rate of curtailment* and the *marginal rate of curtailment* – warrant thorough examination. The difference is best illustrated by way of simulations involving the following REZ Optimisation Model setup:

- Incumbent generation arbitrarily commences at 1400MW wind and 520MW solar PV. These levels have been selected because with this mix, expected REZ transmission line congestion events are zero;
- The REZ Optimisation Model then iterates 300 times, with each iteration progressively increasing the combined installed VRE plant capacity from 1400-2200MW (wind), and 520-1150MW (solar PV).

Model results for each of wind and solar, illustrating the difference between fleet potential, fleet average, and fleet marginal Annual Capacity Factors, appear in Fig.3-4. respectively. In each, the y-axis depicts Annual Capacity Factor and the x-axis measures installed capacity.

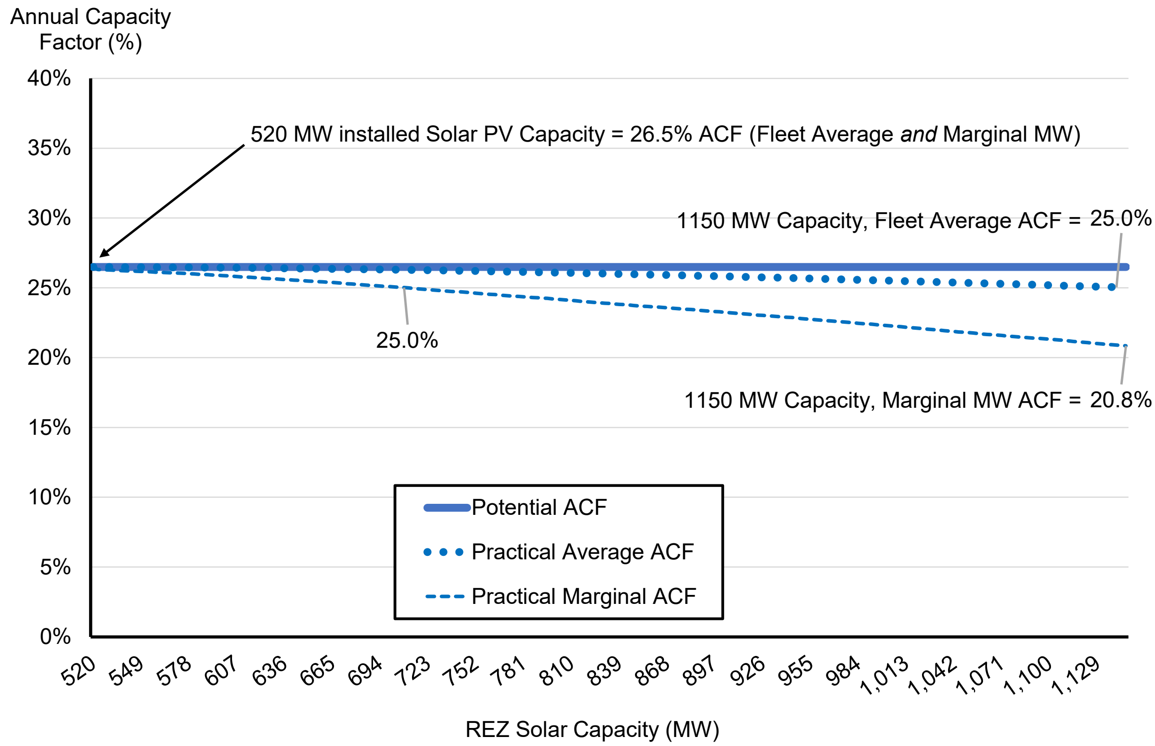
Figure 3: Wind Average vs. Marginal Rate of Curtailment

[5] While deeming the spot price at zero during congestion events, it does not discount the possibility of choosing to recharge at negative prices instead in order to maximise profit.



Focusing on Fig.3 at the origin (where installed wind capacity = 1400MW), output is unconstrained and as a result, potential output of 35% ACF exactly equals practical output. However, as wind capacity progressively increases from 1400-2200MW along the x-axis, *average curtailment* slowly increases due to transmission line congestion. Average production losses culminate at ~5% of output by the end of the data series at 2200MW, meaning the fleetwide *average ACF* has reduced by 5%, from 35.0% to 33.2% as marked. To be clear, this is the *'average rate of curtailment'*.
Now consider the productivity of the marginal MW installed in Fig.3. The very last MW added along the x-axis incurs marginal production losses of ~30% of output, with an ACF of 24.3% as marked. In this sense, the 2200th MW is only 70% as productive as the first 1400MW added. Equivalent results can be seen for solar PV in Fig.4.

Figure 4: Solar PV Average vs. Marginal Rate of Curtailment



What are the policy implications of these results? In a multi-zonal market setup with an open access regime like Australia's NEM, the burden of VRE curtailment is shared amongst producers and so it is the *average rate of curtailment* that matters for renewable plant investors. If the NEM switched to a priority access regime, the burden of curtailment would switch and follow a strict rank order according to entry timing (i.e. last-in, first-off), and so it would be the *marginal rate of curtailment* that would matter for renewable investors. And recall, entry is regulated by the capital markets and in particular, risk averse project banks and their tolerance for curtailment.

In practical terms, in a multi-zonal market setup, open access facilitates more VRE investment within a REZ, the extent of which ultimately being regulated by capital markets. Fig.3 highlights the point at which curtailment reaches 5% of output (or ~33.2% ACF). If 5% lost production is the curtailment rate that capital markets will tolerate, and Power Purchase Agreements (PPAs) are priced efficiently at the margins, open access implies 2200MW of 'bankable wind' investments in the Western Downs REZ as illustrated by the thick dotted line series. Conversely, Fig.3 suggests for a priority access regime (marginal rate of curtailment), only 1550 MW of wind is bankable as illustrated by the thin dashed line series. Again, equivalent results can be seen for solar with Fig.4.

4.2 Optimal mix of wind and solar: open access vs priority access

Having identified the difference between average and marginal curtailment rates, modelling efforts can now turn to identifying the optimal mix of wind and solar in a dynamic market setting. Recall from Section 3 the REZ Optimisation Model incorporates five years of historic hourly price data (Tab.1, 2017-2021 spot prices) including dynamic hourly merit order effects. How open and priority access regimes are simulated is as follows:

1. **Open Access:** Simulating the NEM's existing 'open access' regime formally occurs through Eq.(1). The objective function maximises production subject to the technical, bankability and profitability constraints (Eq.2-5). Here, new VRE

plant enter continuously until economic rents are competed away within the bounds of tolerable curtailment limits (Tab.2, Line 5). In an open access regime, the burden of curtailment is shared amongst REZ entrants on a volume-weighted basis.

2. **Priority Access:** Simulating priority access formally occurs through Eq.(6). The objective function is to maximise profit, and the intuition behind Eq.(6) is priority access establishes a strict entry order. Once marginal economic profits fall to zero, residual transmission line transfer capacity will have reached the *'bankability nadir'* – at which point investment ceases, replicating the entry dynamics of priority access.

Recall from Section 3 the structure of the REZ Optimisation Model involves iterating scenarios (50 iterations per scenario) because with few exceptions, multiple equilibria exist for any given objective function (+/-2% of the median result). This is due to the rich variation in renewable resources and associated merit order effects.

The first simulation optimises wind and solar PV (no storage) to establish appropriate benchmarks for subsequent battery scenarios analysed. Simulation iteration results for the two access regimes, ex-storage, are depicted by scatterplots in Fig.5-6.

Figure 5: Optimal wind and solar capacity: open access vs priority access

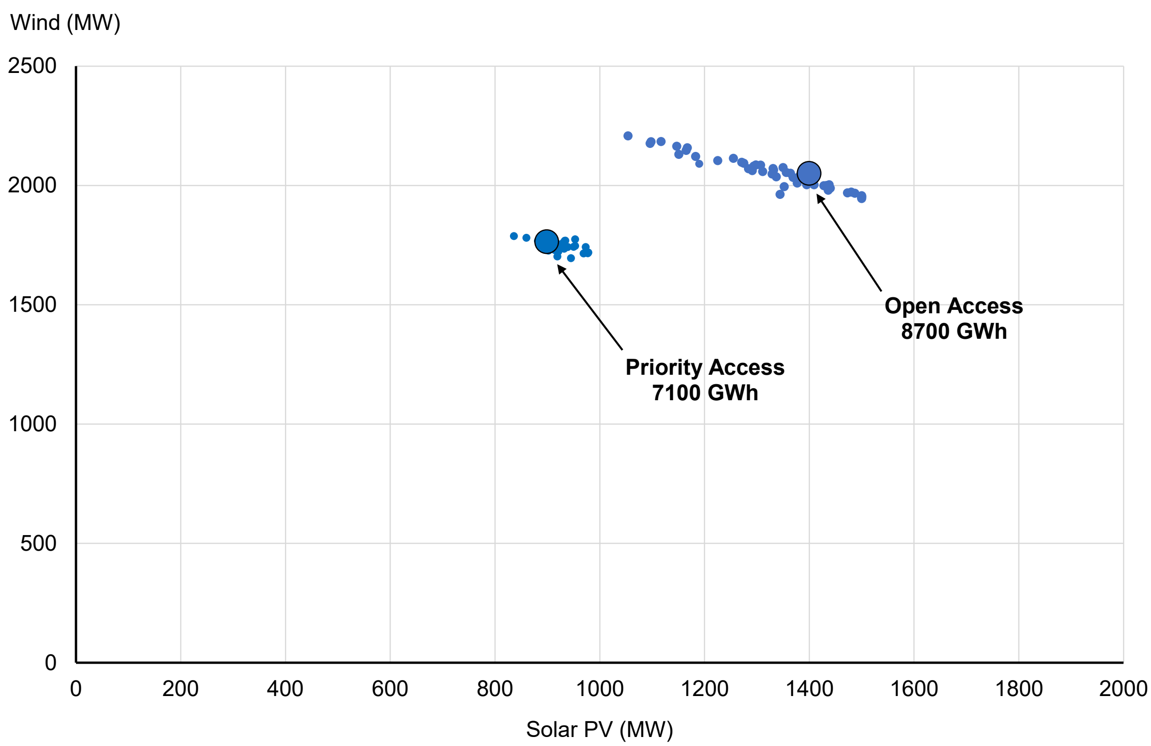
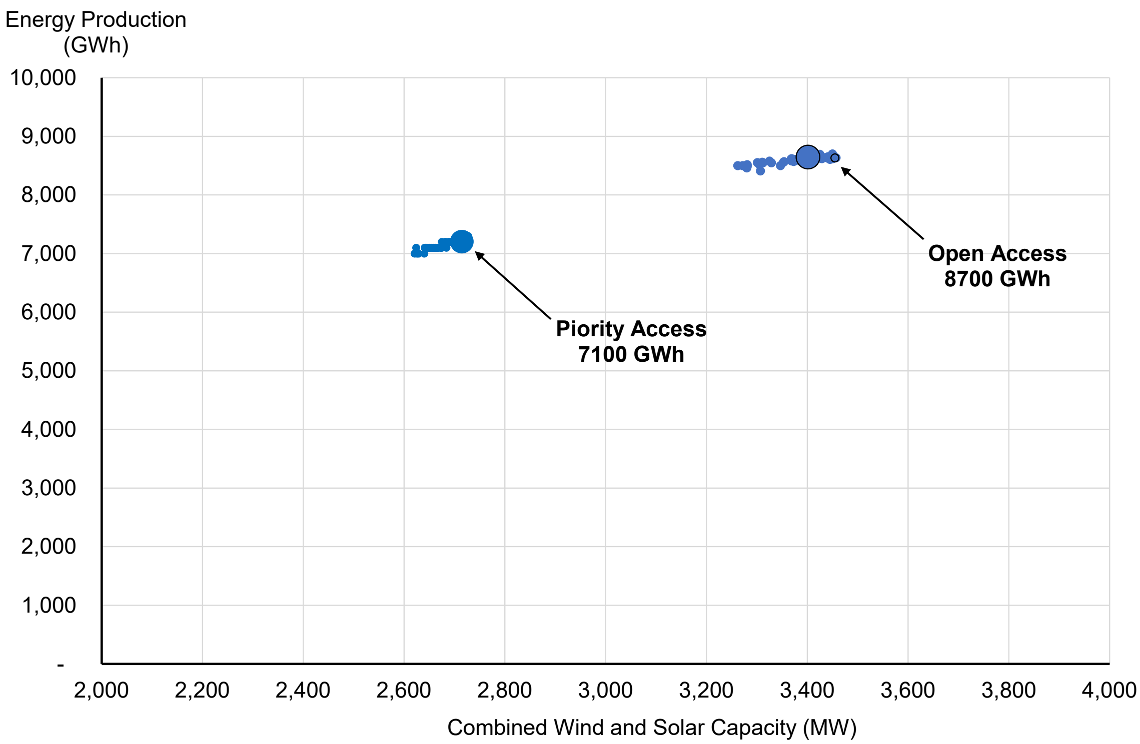


Fig.5 highlights the wide array of viable wind (y-axis) and solar PV (x-axis) portfolio combinations in the open access regime – with the dominant portfolio (larger dot) comprising ~2050 MW of wind and ~1400MW of solar, with aggregate output of 8700 GWh/a. For priority access, the dominant portfolio comprises ~1750MW of wind and ~950MW of solar, with annual output of 7100 GWh.

Fig.6 draws on the same dataset but presents the results in a slightly different way by measuring output on the y-axis, and the combined wind and solar PV capacity on the x-axis. Note the tight range of modelled annual output (y-axis result) against combined wind and solar PV plant capacity for each of the 50 iterations in each access regime. Above all, open access produces consistently higher VRE investment, and output, while meeting all REZ Optimisation Model constraints.

Figure 6: Optimal wind and solar production: open access vs priority access



Tab.6 presents the welfare analysis from the Model. It can be observed that consumers prefer open access (8700GWh/a) as it results in 23% more output than priority access for the same level of transmission infrastructure.

Table 6: Welfare implications - Open Access vs Priority Access

	(Open - Priority Access) ($ Million pa)
1 Chg in Consumer Surplus	$134
2 Chg in Producer Surplus (Wind)	$58
3 Chg in Producer Surplus (Solar)	$73
4 Gross Chg in Producer Surplus	$131
5 *Lost Economic Profits* (Priority Access)	($61)
6 Net Chg in Producer Surplus	$70

In Tab.6, consumer welfare improves by $134m through open access (Line 1). Changes in producer surplus arising from access policy depend on entry timing. Early entrants prefer priority access, since they extract supranormal profits from the market ($61m, Line 5). The NEMs open access regime sees these supranormal profits competed away by latter entrants. Specifically, open access allows latter entrants to proceed to market and remain inside *bankable curtailment rates* because the burden of curtailment is shared across all entrants. Latter entrants would otherwise be *stranded* under priority access. Consequently by comparison, open access expands producer surplus by +$131m, split between wind (+58m, Line 2) and solar (+$73m, Line 3). Net gains between producers amount to +$70m (Line 6). The full model results underpinning Tab.6 appear in Appendix II.

4.3 Adding merchant batteries within Renewable Energy Zones

In the Model, REZ network transfer capacity is a scarce resource. Rising curtailment within a REZ harms VRE producer profits, and places hard limits on bankable renewable plant entry, at ~2050MW of wind, and ~1400MW of solar PV.

Prima facie, it seems logical that adding battery storage within a *fully subscribed* REZ would improve VRE investor prospects. When a battery charges during REZ network congestion events (i.e. creating local demand for spilled VRE output), it may enable more wind and solar PV plant capacity to enter profitably since curtailment rates in the post-battery environment will have reduced back below the *'bankability threshold'*. However as it turns out, such outcomes hinge critically on industrial organisation, and entry timing.

The impact of batteries within a REZ represent the focus of the next set of simulation iterations. For each access regime, two scenarios of industrial organisation are presented:

- Optimised wind and solar with a *coordinated portfolio battery*; and
- Optimised wind and solar with a *competitive // rival battery*.

Before proceeding, a quick overview on the interpretation of scenario iteration results is necessary. Recall from Section 4.2 open access produced the welfare maximising result. The driver of this outcome was maximising bankable VRE capacity and output given model constraints. Consequently in the following analyses, REZ output (constrained by Eq.4-6) can be viewed as the proxy for welfare maximising outcomes – consistent with results in Appendix II.

For the current exercise, the REZ Optimisation Model was allowed to choose any combination of wind, solar and battery storage that would maximise the objective function for open access (Eq.1) and priority access (Eq.6). Recall when entering as a *competitive rival*, the battery strictly follows Eq.(7) – viz. seeking to maximise arbitrage revenues given prevailing zonal spot prices. By contrast, *coordinated portfolio battery* entrants follow Eq.(8). This allows portfolio batteries to re-charge given prevailing zonal spot prices, or during localised REZ congestion events within the REZ (in which case the local price is deemed to be zero inspite of the prevailing zonal price) if this is more profitable. Dispatch of coordinated portfolio batteries also curtail themselves during renewable output congestion events (i.e. again the local price is deemed to be zero in spite of the prevailing zonal price). Clearly, deeming a local price at zero only makes sense to a firm acting in the interests of its portfolio of plant (i.e. wind, solar & battery).

Simulation iteration results are presented in Figs.7-8. Fig.7 commences with the 'no battery' scatterplot results as a benchmark (reproduced from Fig.6, light grey dots), and then layers-in the 2 x 50 iterations from the REZ Optimisation Model for battery storage by access regime (dark blue dots). Note under both access regimes, battery storage boosts annual output modestly, by ~250 GWh. How this is achieved is subtly different by access regime.

For open access, the optimal battery size tends to be smaller (260 MW) with longer duration (4 Hr) by comparison to the priority access battery (345 MW, 3 Hr). These results are intuitive. Priority access places a heavy burden of congestion on the marginal MW (recall Figs.3-4). Consequently with priority access, battery MW are prioritised over MWh. Conversely for the open access regime, the burden of curtailment is shared and therefore battery MWh are prioritised over MW.

Figure 7: Impact of portfolio batteries

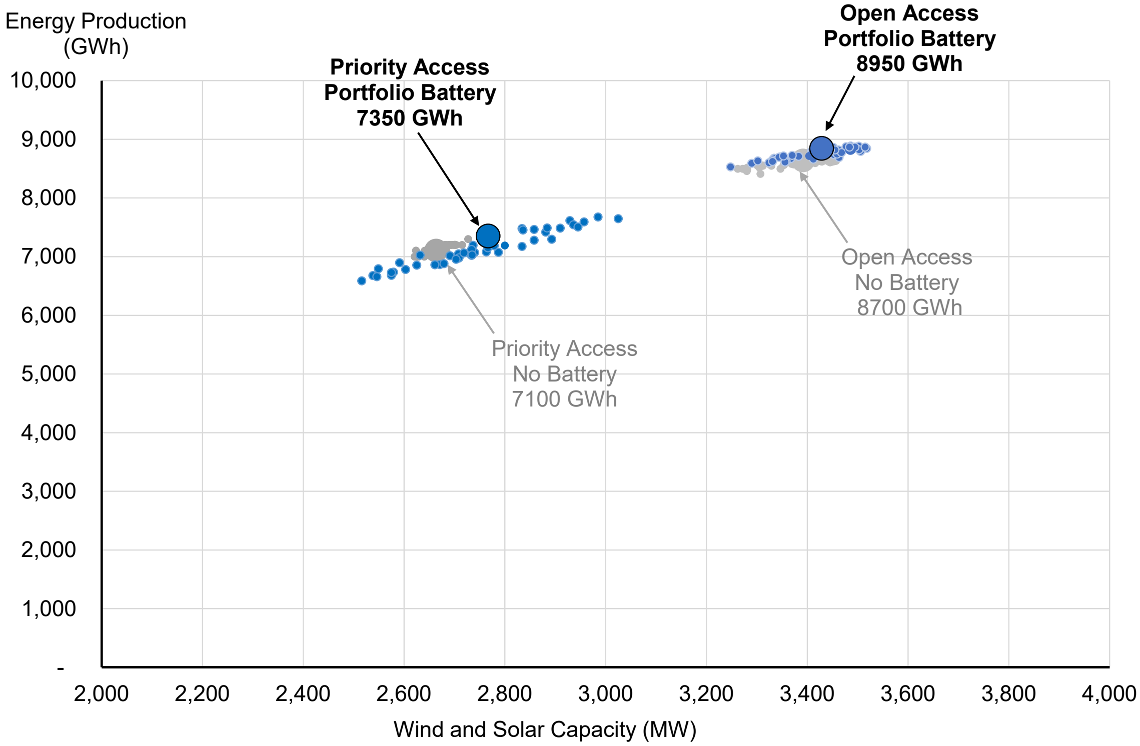
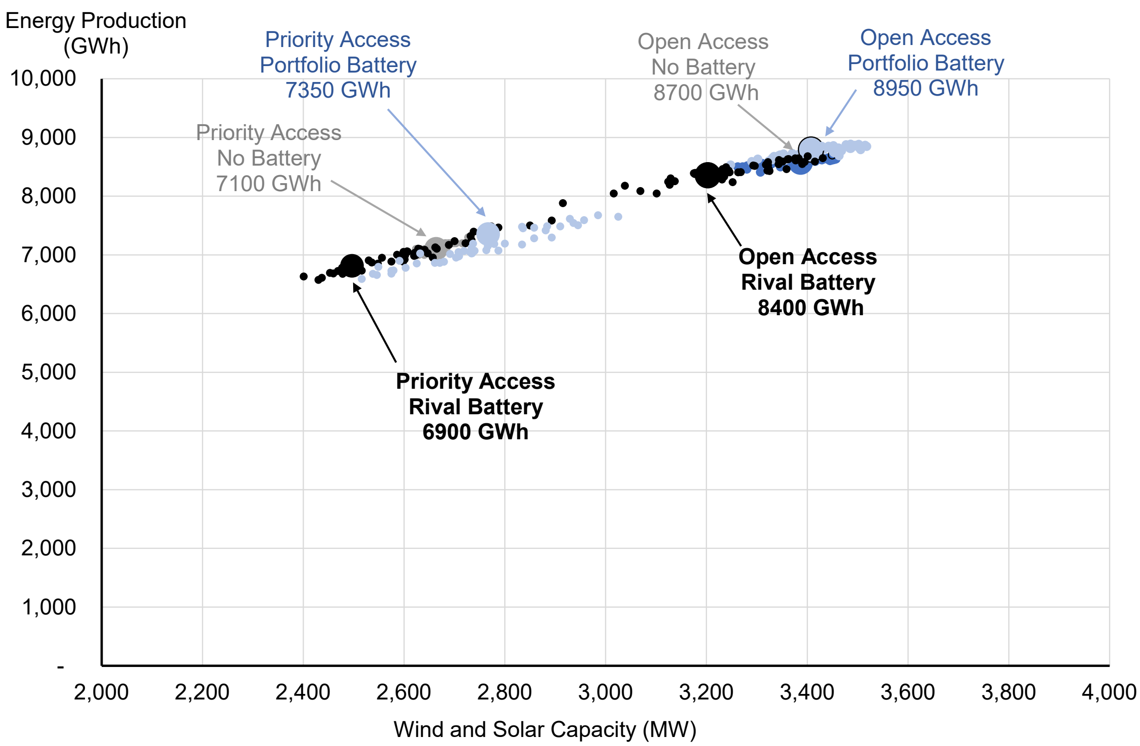


Fig.8 introduces rival batteries (black dots) with the Fig.7 results appearing as light grey and light blue dots. The same relative pattern of battery configuration prevails. Open access induces smaller batteries (MW) with a longer duration (4 Hr), whereas priority access optimises with higher MW (260MW) and lower duration (2 Hr).

Figure 8: Impact of batteries by access regime and industrial form



In Fig.8, the contrasting results between 'competitive rival' and 'coordinated portfolio' battery iterations are striking. In each case, the *rival battery* produces worse results than *no battery at all* from a REZ productivity perspective (albeit noting this applies given the pattern of wind and solar resources on Queensland's Western Downs, and the relative distribution of spot prices in Tab.4[6]). By deduction, competitive batteries within a REZ appear to harm welfare and detract from the task of decarbonisation compared to portfolio batteries. Specifically, a rival battery cannibalises renewable plant capacity by ~200-250MW (x-axis), with output commensurately reducing by as much as ~550 GWh/a (y-axis).

There is an important caveat comes with Fig.8 results. REZ Optimisation Model iterations suggest rival batteries adversely impact welfare. To be clear, this finding relates to rival batteries *'within a congested REZ'* and given the renewable resources modelled. A key advantage of batteries is their comparatively small footprint, and ability to locate at multiple points across a transmission network. What Figs.7-8 suggests is that *within a REZ* approaching its capacity limits, rival batteries aggravate congestion, whereas an optimally-sized and coordinated portfolio battery alleviates congestion and may enhance REZ productivity.

To summarise the 300x iterations of simulations, Tab.7 presents the dominant asset mix and output (10th percentile result). Note that battery impacts on VRE portfolio weightings differs subtly by access regime and industrial organisation. For open access, a portfolio battery induces additional wind (+100MW) at the expense of solar (-50MW) whereas a rival battery induces less wind (-20MW) and solar capacity (-275). For priority access, portfolio batteries materially reduce wind and increase considerably more solar, whereas the rival battery reduces both wind and solar.

Table 7: Portfolio allocation by access regime and industrial form (portfolio, rival)

Open Access		No Battery	Portfolio	Rival
Wind	MW	2,050	2,150	2,100
Solar	MW	1,400	1,350	1,125
Battery	MW	-	260	150
Duration	Hrs	-	4	4
Output	GWh/a	8,700	8,950	8,400
Priority Access		No Battery	Portfolio	Rival
Wind	MW	1,775	1,565	1,755
Solar	MW	950	1,290	800
Battery	MW	-	345	260
Duration	Hrs	-	3	2
Output	GWh/a	7,100	7,350	6,900

To illustrate the evolution of the optimal portfolio battery in an open access regime, Fig.9 runs the REZ Optimisation Model for a 4-hour battery from 1MW of capacity through to 260MW (x-axis) with the REZ pre-populated with 2150MW of wind and 1350MW of solar (per Tab.7). Total plant supranormal profits are measured on the LHS y-axis, while REZ

[6] The distribution of spot prices is important. Specifically, higher intraday spreads may warrant marginally longer duration storage from rival batteries, meaning they then may provide beneficial effects to aggregate REZ production. This in turn may result in a rival battery outperforming a 'no battery' scenario. But to be clear, even in these circumstances a rival battery would not outperform a portfolio battery.

congestion costs, which effectively measures the value of total spilled energy, is measured on the RHS y-axis. Note economic profit is maximised at ~180MW and is competed away as the battery approaches 260MW. If the battery increases in capacity beyond 260MW, it starts to contribute to (rather than relieve) congestion – note the sharp jump in the congestion cost curve at the end of the x-axis.

Figure 9: Evolution of 4 Hr portfolio battery (LHS) vs congestion costs (RHS)

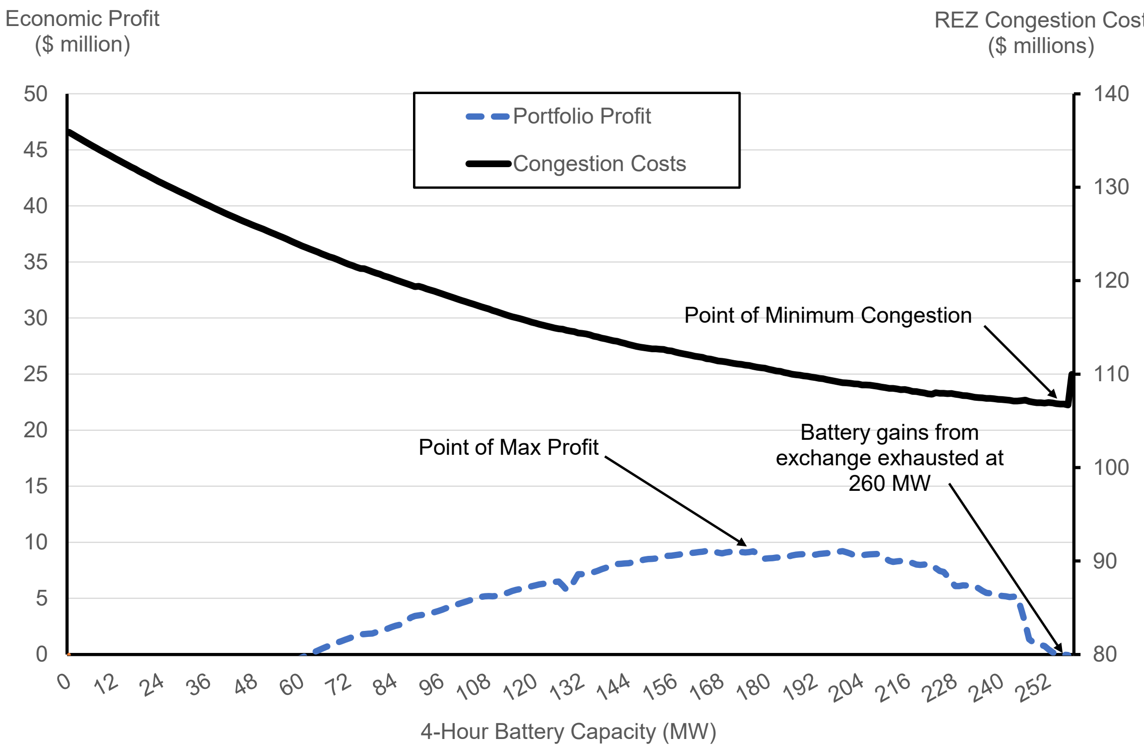


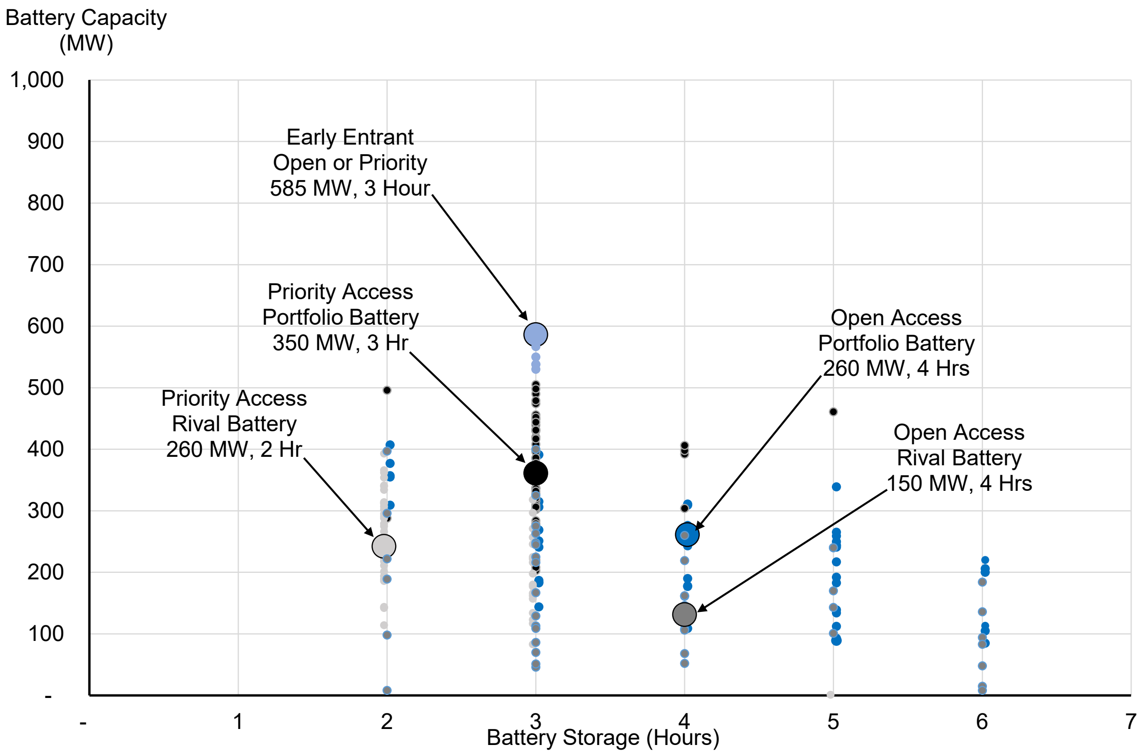
Fig.10 presents the battery size simulation scatterplots for the four scenarios, that is, by access regime and industrial organisation (50 iterations per scenario). As the scatterplots tend to indicate, there is considerable variation in the optimal battery size for any given access regime and industrial form. But to summarise, priority access batteries cluster at higher MW capacity (average 305 MW across the 2 x 50 iterations) but with lower storage duration (average 2.7 hr). Open access batteries tend to cluster at lower capacity (190MW average across the 2 x 50 iterations) but with higher storage (average 4.1 hr), noting the cost of marginal capacity curtailment is less acute. It is also to be noted that entirely different renewable resources, or a material change to expected intraday price spreads, may alter these findings.

Finally in Fig.10, note that a 5th scenario has been highlighted – the *'Early Entrant'* battery at 585MW and 3 hr storage (by far the largest battery by capacity). This was a specific simulation generated by the REZ Optimisation Model under conditions of an under-subscribed REZ in which the anchor tenants were assumed to comprise 1400 MW wind, and 520 MW solar PV (i.e. the scenario used for Figs.3-4). This specific asset configuration was selected because with this level of VRE capacity, the REZ would operate in an unconstrained state (i.e. no congestion).

In this unconstrained state, the Model derived the optimal battery given sunk wind and solar plant capacity commitments of 1400 and 520 MW, respectively. With wind and solar constrained to these fixed MW capacities, the REZ Optimisation Model consistently selected a battery of 3 hours duration, and with very little capacity variation (90th

percentile 540 – 585 MW). This leads to an analysis of whether entry timing matters, in Section 4.4.

Figure 10: Battery size by access regime and industrial form



4.4 Entry timing: early vs. late entrant within a REZ

An important insight from Section 4.3 was that *rival batteries* within a REZ approaching its capacity limits competes with, and therefore may potentially crowd-out, new entrant VRE capacity. Another insight from Section 4.3 was *coordinated portfolio batteries* were smaller in capacity (MW) with more storage (MWh) than rival battery entrants. This raises a subsequent line of inquiry vis-à-vis entry timing. What are the welfare implications of early battery entrants? After all, battery entry times are typically a fraction of solar or wind projects (Clapin and Longden, 2024). Recall from Fig.10 the optimal size of an early entrant, profit maximising battery under open or priority access was 585 MW, with 3 hours duration under the following conditions:

- 1400MW of wind (0% curtailment),
- 520MW of solar PV (0% curtailment), and therefore,
- 585MW, 3 Hour battery (0% curtailment).

Using this zero-constrained plant stock as the starting point, the REZ Optimisation Model then explored two follow-on scenarios:

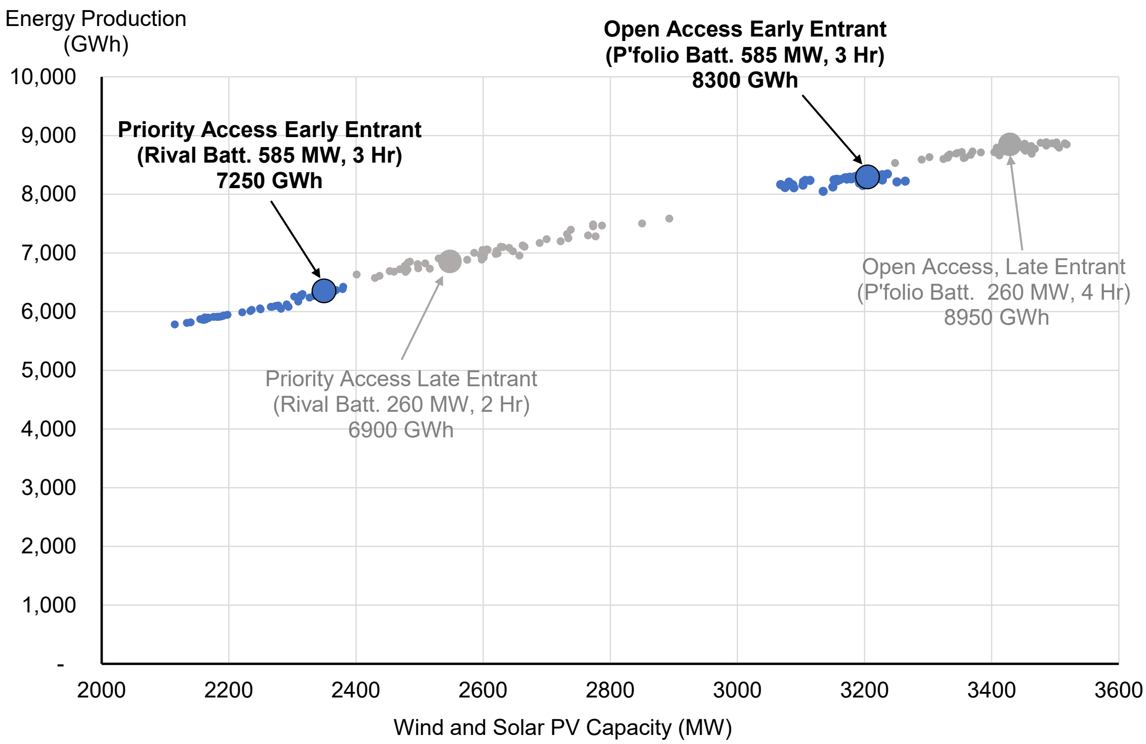
- Optimise VRE within the REZ under an open access regime, given the 585MW, 3 Hour committed battery as a *coordinated (portfolio) asset*; and

- Optimise VRE within the REZ under a priority access regime, given the 585MW, 3 Hour committed battery as a *rival entrant*.

These two scenarios were selected as they would provide bookends of early entrant results. As might be expected, results in Fig.11 illustrate the early entrant battery crowds-out VRE plant capacity from its optimal state in both scenarios. The intuition here is straightforward enough. Under an open access regime, the co-optimised battery tends to be smaller and longer in duration. An early entrant battery finds it profitable to *'oversizes itself'* in capacity (MW) compared to optimality, since there is unconstrained REZ line transfer capacity available. Furthermore, it under-sizes itself in storage (MWh) compared to optimality because there is no spilled energy to arbitrage.

The intuition behind the priority access regime is similarly intuitive. The early entrant battery is larger in both capacity (MW) and storage (MWh) and in a priority access regime, crowds-out potential VRE entrants.

Figure 11: Early Entrant Battery vs. Late Entrant Battery



4.5 Bilateral on-market transactions vs. government-initiated CfD transactions

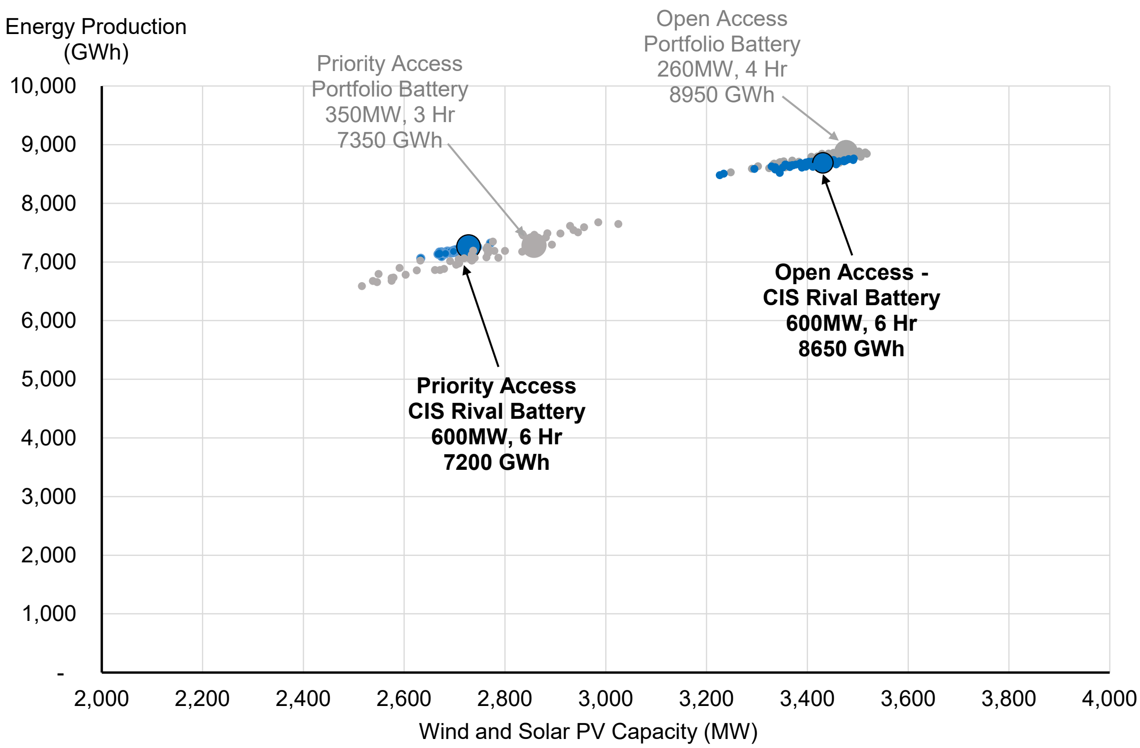
The final set of simulation iterations focus on policy implications for government-initiated CfD auctions. The Commonwealth Government of Australia initiated a policy known as the *Capacity Investment Scheme* or 'CIS' with its current form emerging in late-2023. The stated policy intent is to underwrite 27GW of wind, solar and dispatchable (storage) capacity to reach 82% renewable market share in Australia's NEM by 2030. Thus far, successful CIS battery proponents have typically been 2-4 hours in duration.

Storage in all its formats will become increasingly important for the NEM as system-wide curtailment rates rise. Storage of 6-8 hours (and beyond) will be required (Gilmore, 2024). Accordingly, the final scenario set-up involves a benevolent government underwriting a 600MW, 6-hour battery within a REZ through the taxpayer-funded CIS.

To briefly summarise the workings of the CIS, like all other government-initiated CfD schemes, it is designed to underwrite revenues of a power project asset to enable proponents to optimise project finance. Risk averse project banks prefer government-initiated CfDs given the credit rating of sovereigns, which in turn minimises credit spreads and maximise debt sizing (see Gohdes et al. 2022[7]).

In the Australian case, the CIS achieves such outcomes by awarding successful auction proponents with (taxpayer funded) put- and call option derivatives over the annual profitability of the asset-level 'Special Purpose Vehicle' – in this simulation, a battery. But because the CIS operates at the asset level, any CIS-sponsored battery must, by definition, be a rival entrant because the output of power assets *cannot be hedged twice*. Accordingly, government-initiated CfDs extracts such assets from forward markets, and by implication, from portfolio coordination. Simulation iterations for CIS-awarded batteries under the two access regimes are presented in Fig.12, and contrast with smaller bilateral (on-market) battery transactions. Note in either access regime, a CIS battery reduces REZ productivity.

Figure 12: Govt-initiated CIS Battery vs on-market Portfolio Batteries



While not apparent from the data presented in Fig.12, the annual profitability of the 600MW, 6 Hour battery performs poorly compared to the 585 MW, 3 Hour early entrant. The early entrant earns supranormal profits of ~$4m per annum. If the early entrant battery was increased from 3 to 6 hours duration, profitability deteriorates to a -$22m annual loss. Consequently, a CIS battery under these conditions requires taxpayer underwriting of -$22m per annum given price data in Tab.4.

However, in an open access regime profitable entry by wind and solar remains plausible but at the expense of the CIS-awarded battery. As wind and solar enter and approach

[7] Although as Gohdes et al. (2022) note, whether this is optimal for taxpayers (where alternative BBB-rated on-market transactions exist) is an open question.

their optimal levels (~2045MW wind, ~1380MW solar), the CIS battery incurs annual losses of -$33m per annum. In this instance, consumers are worse off compared to the on-market result of 8950GWh/a as Fig.12 illustrates. Furthermore, taxpayers are worse off through the -$33m annualised losses associated with the CIS battery.

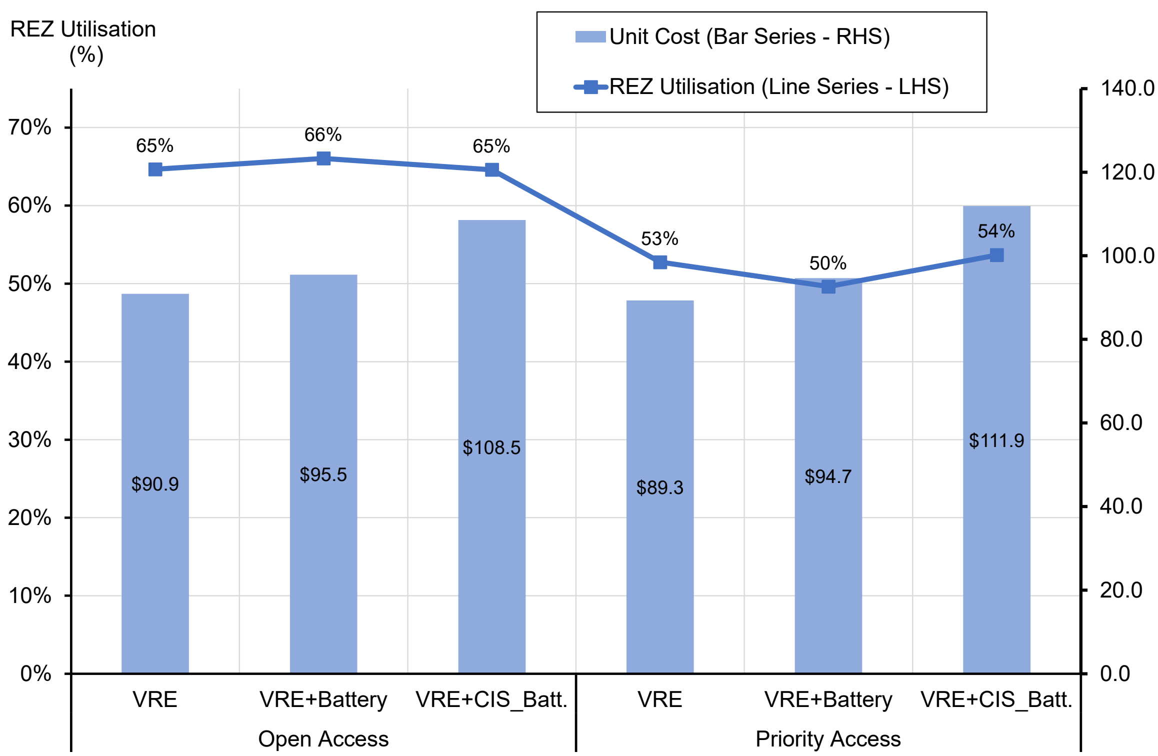
Such results suggest the location of any CIS battery auction transaction is critical in minimising near-term taxpayer losses (i.e. subsidies). Locating the same CIS asset in an unconstrained area of the network, where wind and solar PV cannot be located, will produce better results and be more effective in reducing curtailment without crowding-out local VRE plant capacity.

5. Policy implications

There are four important policy implications for policymakers and REZ investors arising from the ~12 simulation scenarios presented throughout Section 4, as follows.

First, as an absolute general conclusion for a multi-zonal market setup like Australia's NEM, open access maximises welfare. While results in Tab.6 were unambiguous on this point, Fig.8 helped further clarify this outcome across scenarios by comparing various combinations of optimised VRE and battery storage. Fig.13 provides further weight by contrasting the REZ productivity of various scenarios, and reveals open access achieves materially higher output at the same unit cost (+/- $1/MWh). The intuition here is that aggregate congestion under priority access is demonstrably lower than an open access regime (as Fig.3-4 illustrated).

Figure 13: Comparison of REZ Utilisation Rates and Unit Costs



While at first glance it would seem logical that wind and solar average unit costs are minimised when congestion is minimised, such calculations exclude connection costs – and these are minimised when output is maximised. Accordingly, when the fixed and sunk costs of REZ transmission infrastructure are incorporated under a priority access regime, lower VRE unit costs are offset by higher (total) connection costs.

The second policy implication arising from Section 4 is coordinated portfolio batteries are preferred to competitive rival batteries *within a REZ*. Rival batteries compete for scarce REZ transmission transfer capacity and aggravate congestion. Portfolio batteries would be sized, and scheduled, to alleviate congestion. It does so by opportunistically charging during congestion events and withholding dispatch during congestion events.

Third, early entrant batteries within an (uncongested) REZ may harm welfare through oversizing, ex ante, and crowding-out latter-entrant VRE plant. This is the case whether the entrant is a *coordinated portfolio battery*, or *competitive rival battery*. The intuition here is that batteries do not generate renewable energy, they merely help move intermittent output through time. An oversized battery may drive reverse flows into a REZ during renewable lulls, and visibly compete for REZ line access during dispatch cycles. Either way, the effect may be the *crowding-out* of otherwise optimal levels of wind and solar plant capacity.

The final policy implication relates to differences between on-market batteries, and government-initiated CfD auctions for batteries within a Special Purpose Vehicle (or single asset company). No asset in an energy-only electricity market can hedge their output in forward derivative markets twice (e.g. once via the government-initiated CfD, and once to VRE portfolio or end-use customer). The reason for this should be apparent – during a price spike event, the asset would need to pay out difference payments twice – once to each counterparty. Hedging twice in an energy-only market is a sure way of inducing insolvency during scarcity events given the NEMs very high market price cap of ~$17,500/MWh. Consequently, CfD auctions at the asset level *replicate* a rival battery. And as the second policy implication noted, rival batteries within a REZ are likely to harm welfare through aggravating congestion and crowding-out the optimal mix of wind and solar PV plant capacity. Ironically, while wind and solar PV may fall short of their optimum, they may still enter at a rate that degenerates the profits of the government-initiated CfD battery, leaving both electricity consumers, and taxpayers, worse-off by comparison to on-market battery entrants within a REZ.

These policy implications need to be interpreted thoughtfully and in the context of the renewable resources (Fig.2) and prices (Tab.4). It is to be noted that the four policy implications outlined above were carefully caveated with the words *"within a REZ"* and in a multi-zonal market setup where it is assumed credible VRE resources exceed available transfer capacity. These insights *should not* be generalised and interpreted as suggesting that all batteries, in all locations, and in all markets, should be coordinated – and that competition amongst battery proponents should somehow be eliminated.

The issue here is that REZs in Australia's NEM are designed, and declared, because they are locations which exhibit favourable wind and solar resources. Consequently optimising, and indeed maximising, the mix of wind and solar PV plant capacity should take priority *within a REZ*. There is nothing in Section 4 which suggests such a policy should apply across an entire multi-zonal market. And these findings need to be tempered for single zone, nodal market setups and the rich variation in spot market prices that can be expected to emerge as the plant stock changes. Axiomatically, competition amongst battery proponents is important. But in contrast to wind and solar PV plant capacity, batteries can be located throughout the wider transmission network locations due to their comparatively small footprint.

6. Conclusion

Renewable Energy Zones are an important policy initiative of NEM jurisdictional governments, designed to create the necessary hosting capacity for new VRE plant – and stylised on ERCOTs Competitive REZs. Renewable proponents acting independently may otherwise drive duplicate network augmentations which in turn may raise costs above the minimum obtainable, and crucially, over-activate community tension compared to the counterfactual that emerges with a well-designed REZ. There should be no question that, even in a vast NEM region such as Queensland, there will be binding constraints to transmission developments due to the (*understandable*) limits of community acceptance. This is why REZ economics matters at all. It also means when a REZ is developed, optimal productivity should be well planned, and ideally achieved.

In this context, access regimes and the role of battery storage were analysed. The NEM's existing multi-zonal, 'open access' market setup was found to facilitate higher levels of VRE investment within the bounds of *'bankable'* levels of curtailment compared to a priority access regime. Open access shares the burden of spilled energy with all plant facing the average rate of curtailment. Priority access ranks entry with plant following the marginal rate of curtailment.

Deriving the optimal plant stock within a REZ formed the balance of analysis, and the key insight was that as VRE investments approach the limits of lines transfer capacity, the role of battery storage needs to be considered carefully. If transfer capacity is congested, battery storage within the REZ may help alleviate this by moving otherwise spilled energy through space (transmission) and time (battery). What is less obvious is that rival batteries can aggravate congestion, or early-entrant portfolio batteries may be oversized – in either case crowding-out incremental VRE investments. Consequently, portfolio batteries are preferred to rivals, and latter-entrant batteries and preferred to early entrants *within a REZ*.

7. References

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Appendix I - Goncalves & Menezes (2022) NEM spot price coefficients

Hour	Wind			Solar		
	Min95	Est.	Max95	Min95	Est.	Max95
0	-0.00021	-0.00028	-0.00033	0.00350	-0.00067	-0.00095
1	-0.00020	-0.00030	-0.00033	0.00325	-0.00056	-0.00073
2	-0.00019	-0.00033	-0.00036	0.00555	-0.00051	-0.00076
3	-0.00024	-0.00035	-0.00039	0.00421	-0.00041	-0.00061
4	-0.00027	-0.00038	-0.00042	0.00252	-0.00041	-0.00057
5	-0.00028	-0.00038	-0.00044	0.00412	-0.00032	-0.00050
6	-0.00019	-0.00031	-0.00040	0.00534	-0.00015	-0.00070
7	-0.00015	-0.00039	-0.00049	0.00861	-0.00113	-0.00161
8	-0.00023	-0.00029	-0.00034	0.00507	-0.00104	-0.00130
9	-0.00015	-0.00022	-0.00032	0.00456	-0.00082	-0.00116
10	-0.00010	-0.00029	-0.00035	0.00673	-0.00093	-0.00129
11	-0.00009	-0.00033	-0.00040	0.00696	-0.00079	-0.00119
12	-0.00015	-0.00033	-0.00039	0.00903	-0.00086	-0.00119
13	-0.00009	-0.00032	-0.00038	0.00610	-0.00067	-0.00104
14	0.00004	-0.00022	-0.00031	0.00679	-0.00056	-0.00124
15	0.00029	-0.00005	-0.00019	0.01042	0.00013	-0.00105
16	0.00048	0.00003	-0.00018	0.01389	-0.00015	-0.00150
17	0.00066	-0.00001	-0.00026	0.01916	0.00049	-0.00101
18	0.00021	-0.00044	-0.00061	0.01114	0.00074	-0.00045
19	0.00030	-0.00038	-0.00053	0.00941	0.00040	-0.00094
20	0.00005	-0.00028	-0.00033	0.00527	-0.00060	-0.00094
21	-0.00008	-0.00024	-0.00028	0.00348	-0.00068	-0.00092
22	-0.00021	-0.00026	-0.00029	0.00480	-0.00074	-0.00092
23	-0.00017	-0.00024	-0.00028	0.00495	-0.00071	-0.00090

Appendix II

Optimal wind & solar PV capacity – 'open access'

	Wind	2,050 MW	2017	2018	2019	2020	2021	TOTAL
1	Potential Wind Output	(GWh)	5,837	6,714	6,362	6,289	6,214	31,417
2	Practical Wind Output	(GWh)	5,581	6,275	6,002	6,020	5,925	29,802
3	REZ Congestion	(GWh)	257	439	359	270	289	1,614
4	Energy Curtailed	(% of Prod)	4.4%	6.5%	5.7%	4.3%	4.7%	5.1%
5	Economic Wind Output	(GWh)	5,574	6,267	5,952	5,853	5,668	29,314
6	Spill -ve spot prices	(GWh)	7	7	50	167	257	488
7	Energy Spilled	(%)	0	0	0	0	0	0
8	Total Curtail & Spill	(GWh)	264	447	410	437	546	2,102
9	Total Curtail & Spill	(% of Prod)	4.5%	6.7%	6.4%	6.9%	8.8%	6.7%
10	Potential ACF	(% - ACF)	32.5%	37.4%	35.4%	35.0%	34.6%	35.0%
11	Economic ACF	(% - ACF)	31.0%	34.9%	33.1%	32.6%	31.6%	32.6%
12	ACF Loss	(% - ACF)	1.5%	2.5%	2.3%	2.4%	3.0%	2.3%
13	Revenue	$m	677.2	589.0	542.2	312.3	623.2	2,743.9
14	Costs	$m	518.4	518.4	518.4	518.4	518.4	2,591.9
15	REZ Charges	$m	30.3	30.3	30.3	30.3	30.3	151.6
16	Economic Profit	$m	128.5	40.3	-6.5	-236.4	74.5	0.4
17	Unit Revenue	($/MWh)	121.5	94.0	91.1	53.4	109.9	93.6
18	Unit Cost	($/MWh)	93.0	82.7	87.1	88.6	91.4	88.4
19	REZ Cost	($/MWh)	5.4	4.8	5.1	5.2	5.3	5.2
20	Economic Profit	($/MWh)	23.1	6.4	-1.1	-40.4	13.1	0.0
	Solar PV	**1,400 MW**	2017	2018	2019	2020	2021	TOTAL
21	Potential Solar Output	(GWh)	3,266	3,342	3,326	3,184	3,140	16,258
22	Practical Solar Output	(GWh)	3,092	3,042	3,077	3,001	2,934	15,146
23	REZ Congestion	(GWh)	174	300	249	183	206	1,111
24	Energy Curtailed	(% of Prod)	5.3%	9.0%	7.5%	5.7%	6.6%	6.8%
25	Economic Solar Output	(GWh)	3,087	3,033	2,945	2,672	2,449	14,186
26	Spill -ve spot prices	(GWh)	4	9	132	329	485	960
27	Energy Spilled	(%)	0	0	0	0	0	0
28	Total Curtail & Spill	(GWh)	178	309	381	512	691	2,071
29	Total Curtail & Spill	(% of Prod)	5.5%	9.3%	11.4%	16.1%	22.0%	12.7%
30	Potential ACF	(% - ACF)	26.6%	27.3%	27.1%	26.0%	25.6%	26.5%
31	Economic ACF	(% - ACF)	25.2%	24.7%	24.0%	21.8%	20.0%	23.1%
32	ACF Loss	(% - ACF)	1.5%	2.5%	3.1%	4.2%	5.6%	3.4%
33	Revenue	$m	426.6	265.3	233.4	120.2	168.8	1,214.3
34	Costs	$m	227.6	227.6	227.6	227.6	227.6	1,138.0
35	REZ Charges	$m	14.7	14.7	14.7	14.7	14.7	73.4
36	Economic Profit	$m	184.4	23.0	-8.9	-122.1	-73.5	2.9
37	Unit Revenue	($/MWh)	138.2	87.5	79.2	45.0	68.9	85.6
38	Unit Cost	($/MWh)	73.7	75.0	77.3	85.2	93.0	80.2
39	REZ Cost	($/MWh)	4.8	4.8	5.0	5.5	6.0	5.2
40	Economic Profit	($/MWh)	59.7	7.6	-3.0	-45.7	-30.0	0.2
41	Portfolio Output (Line 5+25)	(GWh)	8,661	9,300	8,898	8,525	8,117	43,501
42	Portfolio Profit (Lines 6+36)	$m	312.9	63.3	-15.4	-358.5	1.0	3.3

Optimal wind & solar PV capacity – 'priority access'

	Wind	**1,775 MW**	2017	2018	2019	2020	2021	TOTAL
1	Potential Wind Output	(GWh)	5,054	5,813	5,508	5,446	5,381	27,202
2	Practical Wind Output	(GWh)	4,982	5,660	5,399	5,364	5,288	26,693
3	REZ Congestion	(GWh)	72	153	110	82	93	509
4	Energy Curtailed	(% of Prod)	1.4%	2.6%	2.0%	1.5%	1.7%	1.9%
5	Economic Wind Output	(GWh)	4,976	5,654	5,349	5,200	5,031	26,210
6	Spill -ve spot prices	(GWh)	6	6	50	164	257	483
7	Energy Spilled	(%)	0	0	0	0	0	0
8	Total Curtail & Spill	(GWh)	78	159	159	246	350	992
9	Total Curtail & Spill	(% of Prod)	1.5%	2.7%	2.9%	4.5%	6.5%	3.6%
10	Potential ACF	(% - ACF)	32.5%	37.4%	35.4%	35.0%	34.6%	35.0%
11	Economic ACF	(% - ACF)	32.0%	36.4%	34.4%	33.4%	32.4%	33.7%
12	ACF Loss	(% - ACF)	0.5%	1.0%	1.0%	1.6%	2.2%	1.3%
13	Revenue	$m	605.6	531.0	485.1	276.4	547.8	2,446.0
14	Costs	$m	448.8	448.8	448.8	448.8	448.8	2,244.2
15	REZ Charges	$m	32.5	32.5	32.5	32.5	32.5	162.3
16	Economic Profit	$m	124.3	49.7	3.8	-204.9	66.6	39.6
17	Unit Revenue	($/MWh)	121.7	93.9	90.7	53.2	108.9	93.3
18	Unit Cost	($/MWh)	90.2	79.4	83.9	86.3	89.2	85.6
19	REZ Cost	($/MWh)	6.5	5.7	6.1	6.2	6.5	6.2
20	Economic Profit	($/MWh)	25.0	8.8	0.7	-39.4	13.2	1.5
	Solar PV	**955 MW**	2017	2018	2019	2020	2021	TOTAL
21	Potential Solar Output	(GWh)	2,228	2,280	2,269	2,172	2,142	11,090
22	Practical Solar Output	(GWh)	2,192	2,201	2,212	2,131	2,092	10,828
23	REZ Congestion	(GWh)	35	79	57	41	49	262
24	Energy Curtailed	(% of Prod)	1.6%	3.5%	2.5%	1.9%	2.3%	2.4%
25	Economic Solar Output	(GWh)	2,189	2,195	2,117	1,892	1,737	10,130
26	Spill -ve spot prices	(GWh)	3	6	95	239	356	699
27	Energy Spilled	(%)	0	0	0	0	0	0
28	Total Curtail & Spill	(GWh)	38	85	152	280	405	960
29	Total Curtail & Spill	(% of Prod)	1.7%	3.7%	6.7%	12.9%	18.9%	8.7%
30	Potential ACF	(% - ACF)	26.6%	27.3%	27.1%	26.0%	25.6%	26.5%
31	Economic ACF	(% - ACF)	26.2%	26.2%	25.3%	22.6%	20.8%	24.2%
32	ACF Loss	(% - ACF)	0.5%	1.0%	1.8%	3.3%	4.8%	2.3%
33	Revenue	$m	300.5	192.0	167.2	84.8	118.8	863.4
34	Costs	$m	155.3	155.3	155.3	155.3	155.3	776.3
35	REZ Charges	$m	12.5	12.5	12.5	12.5	12.5	62.7
36	Economic Profit	$m	132.7	24.2	-0.6	-83.0	-49.0	24.4
37	Unit Revenue	($/MWh)	137.3	87.5	79.0	44.8	68.4	85.2
38	Unit Cost	($/MWh)	70.9	70.7	73.3	82.0	89.4	76.6
39	REZ Cost	($/MWh)	5.7	5.7	5.9	6.6	7.2	6.2
40	Economic Profit	($/MWh)	60.6	11.0	-0.3	-43.9	-28.2	2.4
41	Portfolio Output (Line 5+25)	(GWh)	7,166	7,849	7,466	7,092	6,767	36,340
42	Portfolio Profit (Lines 6+36)	$m	257.1	73.9	3.3	-287.9	17.5	63.9