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Renewable Energy Zones: generator cost allocation under uncertainty

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Renewable Energy Zones (REZ) and the associated transmission network infrastructure are an important policy development in Australia's transitioning electricity market. REZs form the basis upon which to expand the renewable hosting capacity of the National Electricity Market (NEM) at scale, while simultaneously minimising the footprint of infrastructure – noting community, cultural heritage and environmental (i.e. biodiversity) sensitivities. In the NEM's Queensland region, REZs are developed outside the regulatory framework as non-regulated or 'merchant' assets, with connecting generators paying user charges. Early REZs involved a small number of committed generators connecting to, and fully subscribing, the REZ asset. Under such conditions, cost allocation is straight forward. But when a geographically dispersed coalition of generators seek to connect over different timeframes and with longer distances involved – the cost allocation task and the tractability of merchant REZ commitment rises in complexity. Since merchant REZs are a novel concept, there is no historic practice to draw from. In this article, we identify the optimal coalition of connecting generators and rely on Shapley's (1951) seminal work to devise a fair and efficient set of user charges, albeit in the context of renewable power project development. We also examine how to deal with transient idle capacity through structured financing and regulatory policy.

Keywords: Renewable Energy Zones, Renewables, Battery Storage, Shapely Value.

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

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February 2025

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Introduction

Renewable Energy Zones (REZs) are a key policy initiative in Australia's National Electricity Market, designed to coordinate multiple renewable projects and minimise marginal transmission costs. If transmission costs were trivial and community attitudes consistently favourable, such coordination may be unnecessary. However, renewable projects and transmission augmentations encroach on private land, compete with environmental (i.e. biodiversity) and agricultural objectives, and risk disturbing cultural sites (Simshauser & Newbery, 2024). Above all, transmission is costly. Consequently, REZs are essential, even in a country as vast as Australia.

REZ policies in New South Wales, Queensland, and Victoria have taken different approaches. NSW opted for a contestable model in 2020, planning large-scale, capital-intensive augmentations capable of hosting ~4.5+ GW in each REZ. But time, complexity and costs were vastly understated with none reaching financial close after five years of activity. Victoria created VicGrid in 2021, with no progress to date. Queensland pursued 'merchant

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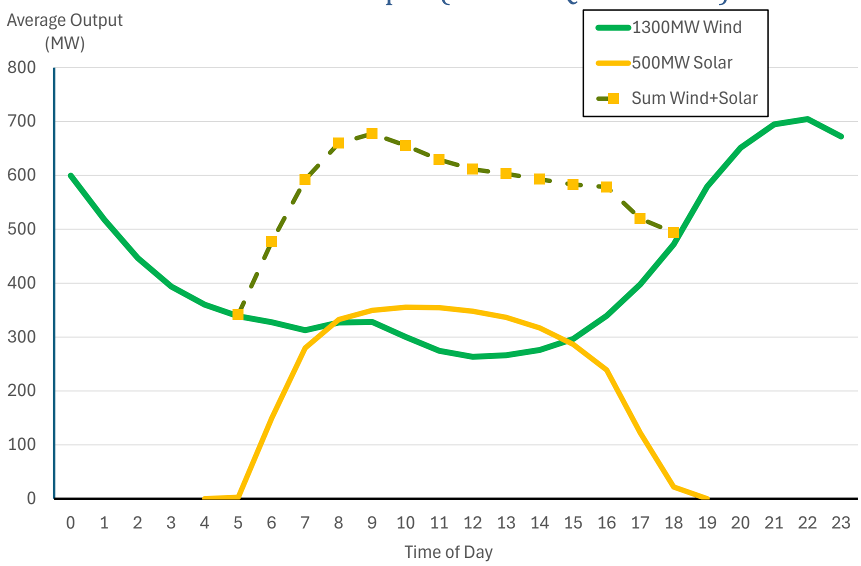
REZs', non-regulated augmentations extending from the transmission backbone and underwritten by generator user charges rather than through the Regulated Asset Base (i.e. paid by end-use consumers). This model enabled rapid deployment, with three REZs planned, developed and energized in just four years – adding a cumulative 4.5GW hosting capacity. Two more REZ (at ~2.5GW each) are under development at the time of writing.

The Queensland model, however, presents challenges. As a merchant framework, revenues come from generators accustomed to paying 'shallow' connection costs. Furthermore, REZs require multiple projects to connect before transmission infrastructure meets financial viability. Yet wind and solar projects take years to develop and secure financing, meaning simultaneous generator commitments could only occur by chance. Additionally, as REZs extend further from the transmission backbone, costs rise. Under such conditions, REZ user charges will invariably exceed generators' (credible) capacity to pay. Accordingly, this article examines three key questions:

1. How should REZ costs be allocated efficiently amongst a coalition of connecting generators with varying locations and transmission network asset requirements?
2. How should user charges and cost recovery be managed under uncertainty vis-à-vis transient idle capacity?
3. How should user charges be structured if REZ costs exceed generators' credible capacity to pay?

Our approach identifies REZ transmission assets, their capital costs, and the optimal mix of connecting generators. Queensland's wind and solar complementarity (see Figure 1) means the efficient level of generation capacity (MW) will exceed REZ transmission network transfer capacity (MW). Using the Shapley value method (Shapley, 1951), we define fair user charges and extend Simshauser (2021) on managing idle capacity amid rising capital costs.

Average Summer Wind and Solar PV output (Central Queensland)



This article is structured as follows: Section 2 reviews the literature, Section 3 introduces models and data, Section 4 presents results, followed by policy implications and conclusions.

Review of Literature

By definition, REZs are areas comprising high quality renewable resources which can be developed at scale (Pack *et al.*, 2021). The origins of renewable zones can be traced back to the Texas // ERCOT market, with the Public Utilities Commission of Texas approving the first 'Competitive REZ' (or 'cREZ') in 2008 (Dorsey-Palmateer, 2020). By 2009, investment in wind capacity had stalled with curtailment rates rising to ~17% (Gowdy, 2022; Du, 2023). This had been anticipated in 2005, and consequently 2400 miles of 345kV transmission was approved at a final investment cost of ~$6.8 billion – specifically to connect remote wind resources with urban load centres (Jang, 2020). Wind transfer capacity in West Texas and the Panhandle was increased from ~6900 to 18,500MW (Du and Rubin, 2018). Following the cREZ, wind investments surged, and curtailment rates were cut to ~0.5% (Dorsey-Palmateer, 2020).

In Australia, REZs have become an important initiative to facilitate additional renewable hosting capacity (McDonald, 2024). In the NEM's Victorian and New South Wales regions, planned REZs are largely being led by state-based developments and as predominantly regulated assets. In the NEM's Queensland region, REZs are subtly different – being comparatively smaller in scale (i.e. ~2GW transfer capacity in each REZ), larger in number, and thus far, merchant transmission investments by a benevolent, state-owned transmission planner (Simshauser and Newbery, 2024).

Queensland's long skinny network is well suited to renewable developments. The transmission backbone runs parallel to Australia's Great Dividing Range (i.e. favourable wind resources), and Queensland is known as 'the Sunshine State'. With more than 60 renewable projects reaching financial close over past eight years, the main advantage of REZs is their ability to coordinate the connection of disparate VRE proponents that would otherwise act independently by seeking singular radial connections to the transmission backbone (Simshauser, 2021; McDonald, 2023; Newbery and Biggar, 2024). In this sense, REZs in Queensland were designed to eliminate otherwise duplicate network investments (Simshauser, Billimoria and Rogers, 2022; McDonald, 2024).

Prior research on merchant REZs in the NEM's Queensland region examined how to manage transient idle capacity through exotic financing structures (Simshauser, 2021), how to exploit the complementarity of renewable resources (Simshauser, Billimoria and Rogers, 2022; McDonald, 2023, 2024), the impact of real-time line ratings on user charges (Simshauser, 2024), access regimes which maximise welfare (Simshauser and Newbery, 2024) and the impact of storage on curtailment rates (Simshauser, 2025). However, in all prior research the allocation of REZ infrastructure costs to connecting generators has been greatly simplified, averaged, and therefore connections under uncertainty have been largely overlooked.

The literature on cost sharing in transmission networks is extensive and has a long-standing history. The use of Game Theory to address multiple aspects of cost sharing in power systems is well known (Contreras, 1997). This interest was inspired in the United States by the deregulation of the electricity industry and the need for multiple generators to co-operate to cost-effectively deliver energy amongst different private entities. A thorough review of approaches to cost sharing in transmission networks in these circumstances is presented in Khan and Agnihotri (2013).

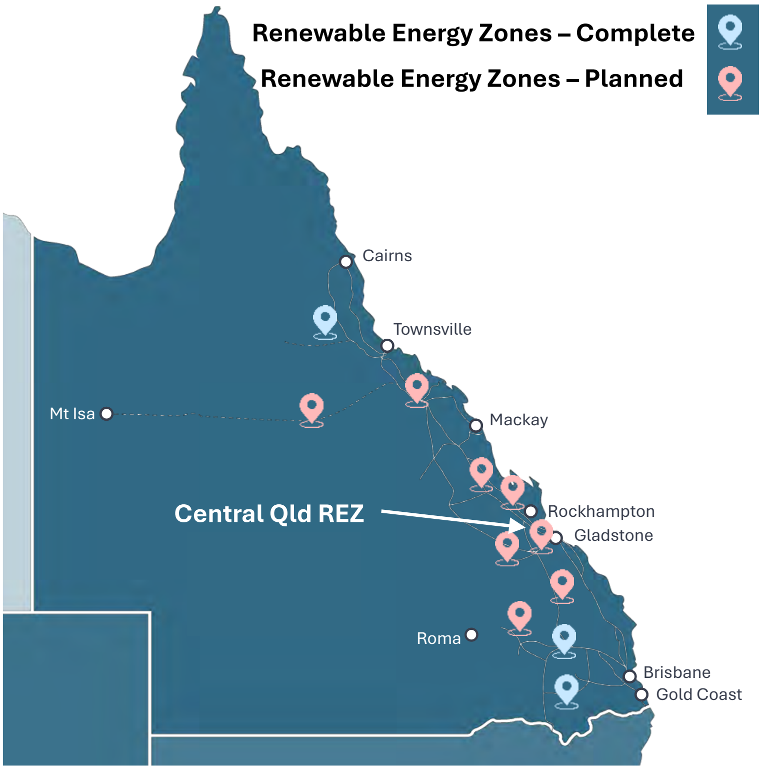
Much of this literature focuses on the classic 6-bus system introduced by Garver (1970). This is a system involving a DC load flow model subject to a series of constraints (e.g. Kirchhoff's laws). Our situation is different to the bus literature in that our focus on REZs leads to a joint asset that power generators can access (it effectively becomes a sink for all generated power). Our equivalence to the traditional bus approach would be to take the volume weighted production price as the synthetic version of a bus system (price being a proxy for demand with intermittent resources). However, this is still not a good match, as in our REZ situation there are definite economies of scale with shared assets, hence our approach in this article. The closest research to the work presented in this article is that found in Nylund (2014), where multiple entities in different countries collaborate to regionally expand power networks. We apply the concepts of cost sharing based on cooperative game theory (Hougaard, 2009). Other approaches from the cost allocation literature are also possible. However, these approaches don't consider coalition structures and combined cost profiles of multiple players – which are relevant for the current context. In addition, given the costs of projects considered in this article are transferable between parties, a TU-game (or transferable utility game) is an appropriate approach to model the current situation (see Shellshear and Sudhölter, 2009).

For the above reasons, in this article we choose to solve the current cost allocation problem using the Shapley Value (Shapley, 1957) given its properties are desirable characteristics sought in the current context.

REZ Data and Models

Our task is to examine the allocation of REZ costs to a coalition of participating, but rival, renewable generators with imperfect entry. The specific area (and weather data) being modelled is a REZ in Central Queensland (Fig.2).

Renewable Energy Zones in Queensland



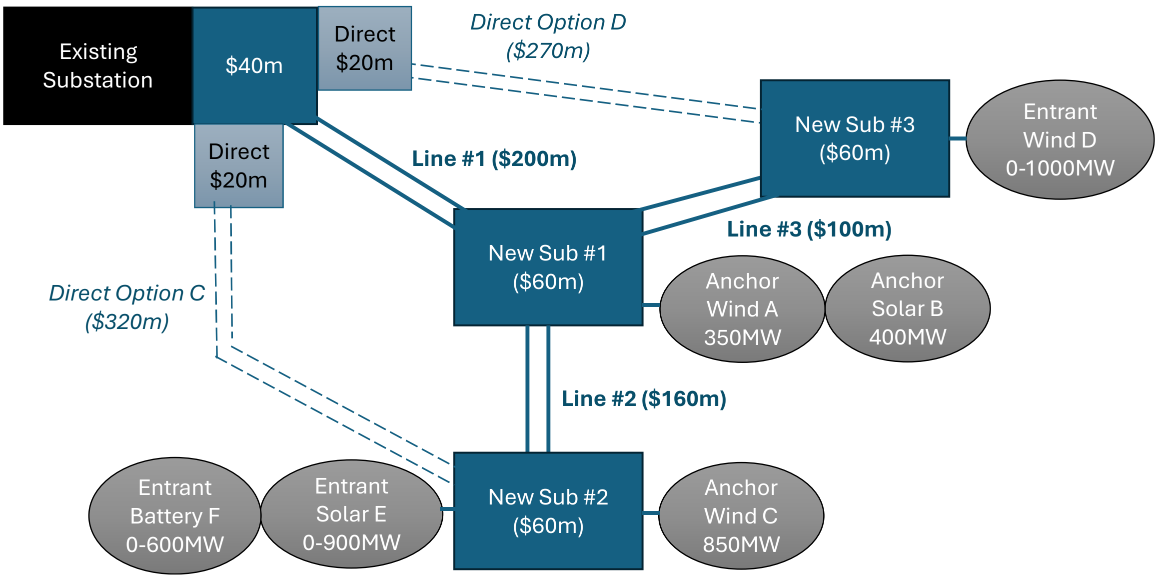
The layout of our example REZ is presented in Fig.3 and to summarise, there are three anchor tenants (Wind A, Solar B, Wind C) which trigger investment in Lines #1 and #2, and Substations #1 and #2 along with a $40m modification to the Existing Substation. Note also in Fig.3 there are three potential entrants, 'Wind D' (which triggers investment in New Sub #3 and Line #3), along with 'Solar E' and 'Battery F'.

Note 'Wind C' and 'Wind D' have alternate options to connect to the existing substation, involving Direct Options 'C' and 'D', respectively, along with $20m costs at the Existing

Substation. It can be seen that the optimised REZ involves an investment of ~$680m (i.e. the sum of Lines 1-3, Substation 1-3 and the $40m expansion of the Existing Substation). If each generator seeks to pursue their own direct connection, resulting in the removal of Line #2 and Line #3, and the addition of Direct Option C and Direct Option D, total investment rises to $1b.

Our task is to identify the optimal REZ development plan and associated generation capacity, along with an efficient and fair allocation of REZ costs in the form of user charges, noting imperfect and uncertain generator entry.

Renewable Energy Zone Layout



REZ transmission line capacity is assumed to comprise double circuit 275kV radial connections in Central Queensland which traverse from the transmission backbone (Fig.2). As Fig.3 notes, the radial REZ network comprises three new connection points with up to six new generators – anchor tenants who are fixed in MW capacity, and entrants with a credible range of capacity options. REZ network transfer limits are driven by conductor type, allowable operating temperatures with seasonal line ratings at ~200km from Australia's coastline. Seasonal transfer limits, total capital cost and total annual user charges are as follows:

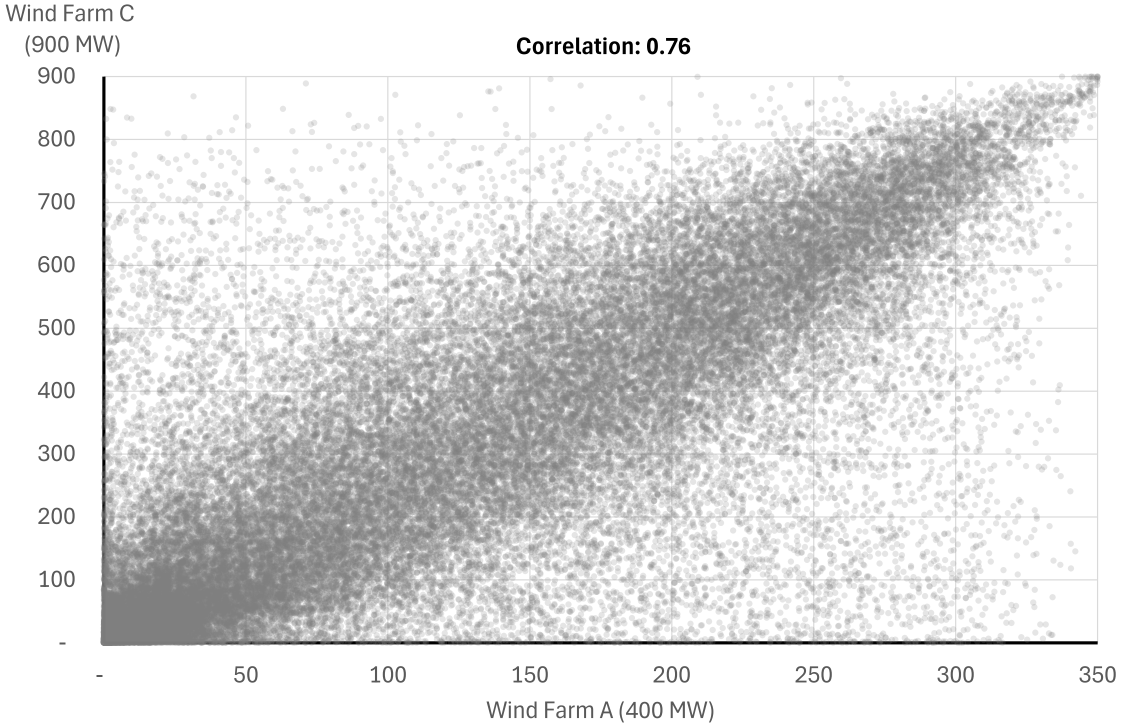
Double Circuit 275kV REZ, Seasonal Transfer Limits and Costs

	Normal Rating (MW)
Summer	1535
Spring/Autumn	1755
Winter	1915
Total REZ Capital Cost	$680 million
Annual REZ User Charges	$68 million pa

Wind and solar data

Fig.1 noted the diurnal pattern of VRE in Central Queensland's exhibits a level of complementarity, with average wind output rising either side of solar PV output. The hourly correlation between wind and solar is -0.42 during summer, -0.29 in winter and -0.43 during spring. Even for the same technology (Wind A and Wind C in Fig.3) at different locations, output exhibits high but not perfect correlation, as Fig.4 illustrates.

Six years of wind output at adjacent locations (Central REZ)



As discussed in Section 1, given the complementarity of wind and solar, the optimal installed VRE plant capacity (MW) will vastly exceed REZ transmission line transfer limits (MW). However, only time-sequential modelling is capable of identifying the true extent of portfolio diversity (see Guerra et al., 2020; Merrick et al., 2024), and this is where our REZ Optimisation Model becomes necessary (Section 3.4).

We rely on 6½ years of historic hourly weather reanalysis from 2018-2024 (drawn from an updated database contained in Gilmore et al., 2022). A summary of the appropriately time-matched spot price statistics over the same period appears in Tab.2.

Statistical summary of spot prices and dispatch-weighted prices (2024$)

	Spot Prices		2018	2019	2020	2021	2022	2023	2024	AVG
1	Time Weighted Average	($/MWh)	90.1	85.0	48.9	101.9	146.2	94.1	110.3	95.6
2	Wind Dispatch Weighted	($/MWh)	90.6	89.8	53.6	107.6	161.0	115.5	123.8	104.2
3	Wind % of Average Spot	(%)	101%	106%	110%	106%	110%	123%	112%	109%
4	Solar Dispatch Weighted	($/MWh)	88.3	78.8	44.8	69.2	89.1	68.0	70.1	73.4
5	Solar % of Average Spot	(%)	98%	93%	92%	68%	61%	72%	64%	77%
6	Negative Price Events	(Hrs)	10	157	388	546	423	1190	394	3108
7	90th Precentile Spot Price	($/MWh)	60.5	47.4	19.5	17.8	24.0	-20.8	7.1	24.0
8	10th Precentile Spot Price	($/MWh)	128.2	127.9	74.0	141.2	246.0	172.2	204.4	163.5
9	Coefficient of Variation*	($/MWh)	0.6	0.6	1.6	4.6	2.6	2.6	3.1	2.9
10	Kurtosis	($/MWh)	1,237.0	32.5	746.6	660.9	405.9	503.8	491.1	1,205.1
11	Skewness	($/MWh)	25.6	-1.0	22.7	22.5	18.4	20.2	20.4	29.5
12	Mininum Spot Price	($/MWh)	-370.4	-738.9	-796.5	-1,000.0	-71.8	-83.2	-88.8	-1,000.0
13	Maximum Spot Price	($/MWh)	2,992.4	462.4	2,964.0	17,349.0	10,694.2	8,243.7	10,502.8	17,349.0

* Coefficient of Variation based on hourly data (Std Dev / Time Weighted Average)

Source: Australian Energy Market Operator.

Renewable plant capacity additions impact hourly prices differentially. During daylight hours, adding solar PV has a depressing effect (i.e. merit order effect) on spot prices– but as Bushnell and Novan (2021) and Gonçalves and Menezes (2022) identify, spot prices rise during non-solar periods. The same is true of wind output. Consistent with the modelling approach in Simshauser and Newbery (2024), our REZ Optimisation Model recasts historic hourly prices using hourly regression coefficients from Gonçalves and Menezes (2022) on a dynamic basis as wind and solar capacity levels are altered. The coefficients are outlined in Appendix I.

Renewable and Storage Plant costs

Our *Project & Corporate Finance Model* (PCF Model) is a multi-period power project program designed to generate commercial-grade unit cost estimates of renewable and storage technologies. As the title suggests, the model is capable of producing either on-balance sheet or project financings. The generalised post-tax, post-financing Levelized Cost of Electricity estimates calculated by the model incorporate co-optimised structured finance and taxation variables. Model input parameters appear in Appendix II and are broadly consistent with Gohdes et al., (2022, 2023), while the model logic appears in Appendix III. Estimated entry costs from the PCF Model are as follows:

- Entry Cost of Wind — $79.2/MWh (excl. REZ user charges, ACF = 33%)
- Entry Cost of Solar PV — $51.1/MWh (excl. REZ user charges, ACF = 27%)
- Entry Cost of Batteries[1] — $10.7/MWh for 1st hour storage,
  $5.0/MWh for each subsequent hour of storage.

Overview of REZ Optimisation Model

The REZ Optimisation Model follows a Stackelberg setup in a manner analogous to Hassanzadeh Moghimi et al., (2024). We start with a welfare maximising and benevolent transmission utility as the leader with renewable generators being the followers. The first stage of the model setup commences with the benevolent transmission utility identifying the optimal mix of generation plant for a given access regime, while the second stage involves conventional Nash-Cournot games amongst profit-maximising generators in two timeframes involving (i) least cost plant investment in planning timeframes, and dynamic plant dispatch with hourly resolution in operational timeframes. Our REZ Optimisation model is grounded firmly in welfare economics, as follows:

[1] 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.

Let $r \in R$ be the set of generators, each with installed capacity K_r. The REZ has network transfer capacity which varies by season, REZ^s. Let $t \in T$ be the set of hourly dispatch intervals over our 6½ year simulation. In the model, $C_{r,t}$ is the divisible unit cost of each generation technology regardless of scale ($/MWh) and represents an output from our PCF Model. Let plant availability $\beta_{r,t}$ be a binary variable equal to an element of the set $\{0,1\}$. Let the ex-post or actual output of generator r in trading interval t be $q_{r,t}$ while the ex-ante 'expected' output be $e(q_{r,t})$, noting that expected output can be adversely impacted by uncertain events, viz. REZ transmission line congestion and negative price events which are ultimately constrained by a bankable curtailment rate (δ_r). The relevant spot price for each trading interval is given by $p_{r,t}$. The welfare maximising objective function from this point becomes a relatively straightforward one:

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

S.T.

$$\sum_{r\in R} q_{r,t}\ \leq K_r \cdot \beta_{r,t}\ \forall\ r \in R, t \in T, \tag{2}$$

$$\sum_{r\in R} q_{r,t} \leq REZ_t^s\ \forall\ t \in T \mid \left(q_{r,t} = 0\ if\ p_{r,t} < 0\right) \tag{3}$$

$$\left(\sum_{t\in T}\sum_{r\in R} q_{r,t}\right) \geq \left[\sum_{t\in T}\sum_{r\in R}(1-\delta_r)\cdot e\left(q_{r,t}\right)\right], \tag{4}$$

$$\left(\sum_{t\in T}\sum_{r\in R} q_{r,t}\cdot p_{r,t}\right) - \left(\sum_{t\in T}\sum_{r\in R} K_r \cdot C_{r,t}\right)\ \geq 0. \tag{5}$$

The Objective Function set out in Eq.(1) seeks to maximise production subject to a set of constraints. Wind and solar projects bid their output into the spot market at the relevant marginal running cost (i.e. $0/MWh). Eq.(2) ensures that generation dispatch is constrained by both total plant capacity and plant availability $K_r \cdot \beta_{r,t}$. Aggregate output for trading interval $t \in T$ is also constrained by the transmission line transfer limits REZ_t^s which adjust by season in Eq.(3). Crucially, wind and solar curtailment rates (δ_r) which drive the difference between expected $e\left(q_{r,t}\right)$ and actual output $\left(q_{r,t}\right)$ must not exceed the exogenously determined *bankability limit* associated with contemporary project financings as outlined in Gohdes et al (2023) and Simshauser & Newbery (2024). Finally, any production maximising solution is also constrained by normal returns in Eq.(5). Here, renewable fleet revenues are derived by production output $q_{r,t}$ and spot prices $p_{r,t}$ with normal profit being determined by the point at which unit revenues meet plant entry costs $C_{r,t}$. Supernormal profits arise when revenues exceed entry costs because in the PCF Model, entry costs include a normal return to equity. The objective function for profit maximising scenarios (OBJ_{EP}) is similarly straight forward:

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

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

In our model, batteries h form part of the potential coalition of REZ generators such that $h, r \in R$. Batteries may be a *rival or form part of a portfolio*. A rival battery strictly maximises arbitrage profit each day $\left(Arb_{h,d}\right)$ for any given level of storage, j, via generating $\left(q_{h,t}\right)$ at round trip efficiency (γ_h) during maximum daily spot market price events $(pmax_t)$, and re-charging $\left(-q_{h,t}\right)$ during minimum spot price events $(pmin_t)$, such that $q_{h,t} \in$

$[-K_h, +K_h]$. We assume batteries constrain their activity to one cycle per day with the optimisation ensuring the diurnal storage balance $\left(\sum_{t=1}^{n} q_{h,t} = 0\right)$ is met. This is formally implemented in the model with perfect foresight of day ahead spot prices. Consequently, bids and offers are dynamically solved each day to meet the objective function[2]:

$$Arb_{h,d} = \left(\left(\sum_{t=1}^{n} pmax_{h,t} \cdot q_{h,t} \cdot \gamma_h\right) + \left(\sum_{t=1}^{n} pmin_{h,t} \cdot -q_{h,t}\right)\right), \tag{7}$$

For portfolio batteries, rechanging and generation dispatch requires a different approach. In any trading interval where aggregate wind and solar output $q_{r,t}$ exceeds seasonal transmission line ratings REZ_t^s, the spot price for the battery during that interval $(p_{h,t})$ is deemed $(\hat{p}_{h,t} = 0)$, meaning that the any signal to generate disappears, and may provide an opportunity to re-charge at a zero price:

$$Arb_{h,d} = \left(\left(\sum_{t=1}^{n} \hat{p}max_{h,t} \cdot q_{h,t} \cdot \gamma_h\right) + \left(\sum_{t=1}^{n} \hat{p}min_{h,t} \cdot -q_{h,t}\right) \middle| if \begin{cases} \sum_{r=1}^{R} q_{r,t} \geq REZ_t^s, \hat{p}_{h,t} = 0 \\ \sum_{r=1}^{R} q_{r,t} < REZ_t^s, \hat{p}_{h,t} = p_{h,t} \end{cases}\right). \tag{8}$$

Overview of Cost Sharing Model

Our approach to efficient and fair cost allocation amongst the final coalition of connecting generators, $h, r \in R$, leverages Game Theory techniques to provide a set of market-inducing characteristics of a cost sharing solution. Game Theory is a rich theoretical edifice providing a versatile set of techniques which have been applied to everything, from apportionment methods (Shellshear, 2010) to electricity markets (Contreras, 1997).

Our cost allocation approach is based on a set of desirable principles, viz. a cost sharing approach for the coalition of generators should fulfill and build upon principles that are known to produce closed-form cost sharing solutions that can be applied directly.

Before we explain the desirable characteristics of a cost sharing solution, we provide four *core principles* that guide our cost sharing solution, which in turn provide the right incentives for generators to participate in REZs:

1. REZ cost sharing should incentivize generators to co-operate as a coalition, that is, provide each *expected generator* with a better solution than if they attempt to act independently.

2. Any cost sharing solution for the coalition of expected generators must always exist irrespective of the cost profiles of each generator, because infrastructure costs associated with connecting each generator are not obliged to adhere to any specific mathematical structure (meaning our solution cannot guarantee a non-empty core).

3. Any cost sharing solution must identify a single unique value to ensure each expected generator faces a binary option to join the coalition (i.e. no ex-post negotiations are required); and finally,

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[2] It is to be noted that in a zonal market setup when congestion occurs and inframarginal rents are available given prevailing spot prices, generators behind a constraint may each bid below their marginal cost in order to create tied-bids, in which case their output will be dispatched on a volume-weighted basis. This is a known distortion in zonal market setups and primarily impacts producer welfare and may adversely impact resource costs.

4. The cost sharing solution must observe a broader *capacity to pay* constraint, meaning there is an affordability cap which may leave some of the costs recommended by the cost sharing protocol to be recovered from other sources.

Based on the above considerations, a cooperative game theory approach makes sense as our problem structure is a standard cost sharing problem with a group of players, or rival generators, that ultimately need to be coordinated by the benevolent transmission network planner in a transparent manner (noting direct cooperation amongst rivals violates competition law).

We now introduce the needed game theoretical notation. Let $N = \{1, 2, 3, \ldots, n\}, n \in \mathbb{N}$, represent the set of players in the game. A coalition S is defined as a subset of N, i.e. $S \subseteq N$. The null set is called the empty coalition and the set N is called the *grand coalition*. A *game* is a pair, (N, v), where v is a real-valued function, called the characteristic function, defined on the subsets of N, i.e., $v: 2^N \rightarrow \mathbb{R}$, that satisfies $v(\emptyset) = 0$. The value $v(S)$ represents the value of a coalition S, which in our case is the minimal capital cost the coalition S can guarantee by acting on its own and coordinating with its own members, irrespective of what other players and coalitions do. Another useful concept is that of monotonicity. A game is *monotonic* if for all coalitions $S, T \subseteq N$, with $S \subseteq T$, implying that:

$$v(S) \leq v(T)$$

The cost allocation function in our game is defined by the cost of the minimum transmission infrastructure required to serve the coalition of generators, noting such a definition means the game is monotonic. Specifically, we have a set of players, $h, r \in R$, and we number them, $N = \{1, \ldots, n\}$ where $n = |R|$. For a coalition S, let $C(S)$ be defined as the minimum cost infrastructure required to connect the generators in S to the REZ including the REZ costs. The coalition function v is then defined as $v(S) \coloneqq C(S)$. This defines a game (N, v). The minimum infrastructure costs are provided below in the Model Results section.

A cost allocation rule is a function, $\phi(N, v) \rightarrow \mathbb{R}^n$, defined on a game (N, v) which assigns to each player a cost share, $\phi_i(N, v) \in \mathbb{R}$ to each player $i \in N$ such that,

$$\sum_{i \in N} \phi_i(N, v) = v(N). \tag{9}$$

In the following we supress the (N, v) in our solution notation as the specific game will always be clear. In addition, we will write $\phi(S) \coloneqq \sum_{i \in S} \phi_i$. Based on the two principles above, our solution concepts must be defined for all games and satisfy the following constraint:

$$\phi_i \leq v(i), i \in N. \tag{10}$$

Any vector satisfying the previous constraint and $\phi(N) = v(N)$ from Eq.(9) is called an imputation.

When allocating REZ costs, we have a number of desirable or 'optimal' criteria that any solution should fulfill. These desirable properties are as follows (note there are other criteria such as *anonymity* which may or may not be required, hence are not included below):

1. *Individual Rationality*: Each generator should pay less than what it would cost them were they to act in isolation per Eq.(9).

2. *Linear*: For each REZ, the cost allocation should be additive across other zones, i.e. for each REZ sub-game, the combined cost solutions should be linear.

3. *Dummy generator*: if a generator causes no cost, it should not be charged anything.

4. *Efficiency*: The sum of costs allocated to generators should equal the total cost, i.e. no cost should not be covered, and the sum of allocated costs should not exceed total costs per Eq.(10).

5. *Symmetry*: Generators with identical cost profiles should have the same solution value, i.e. for $i, j \in N, i \neq j$, if $v(S \cup i) = v(S \cup j)\ \forall\ S \subseteq N, i, j \notin S$, then $\phi_i = \phi_j$.

6. *Monotonicity*: Generators with higher transmission network requirements should pay more, i.e. if $i, j \in N, i \neq j$, if $v(S \cup i) \leq v(S \cup j)\ \forall\ S \subseteq N, i, j \notin S$, then $\phi_i \leq \phi_j$.

These six criteria are considered highly desirable, to which one could add further criteria such as $\phi(S) \leq v(S)$. However, by adding this additional criterion we violate our second core principle above, that a solution always exists (an imputation that satisfies this additional condition belongs to the core, which is empty for some games). By keeping the above six criteria, we are able to guarantee a suitable solution concept that always exists and has a simple expression and intuitive interpretation, the Shapley value, and also fulfills our four core principles.

The Shapley value is defined for a game (N, v) as follows:

$$\phi_i = \sum_{S \subseteq N \setminus i} \frac{|S|!(|N|-|S|-1)!}{|N|!} (v(S \cup i) - v(S)), \tag{11}$$

where $|S|$ stands for the cardinality of S. It is known that the Shapley value fulfills the six criteria above (Hougaard, 2009) and can be interpreted as a type of average across a particular contribution by a connecting generator to a coalition of connecting generators, independent of the way that the generator joins the REZ coalition.

Other solutions such as the core, von Neumann-Morgenstern set, nucleolus, kernel, tau value (Hoougard, 2009) and others may also be relevant. However, each of these options was rejected for the following reasons:

- *The core*: it is not guaranteed to be non-empty as mentioned above.

- *The von Neumann-Morgenstern set*: it is not guaranteed to be non-empty.

- *The nucleolus*: we are not interested in the excesses of each coalition and trying to maximise them as this is not a realistic aspect of our model given geographical limitations – that is, generators either join the REZ or not, and cannot form another sub-coalition given community and environmental limits (i.e. of developing transmission assets).

- *The kernel*: although it always exists, it does not provide a unique payoff outcome, however, a set of outcomes, hence violating one of our principles.

- *The tau value* is defined on the set of quasi-balanced games and so is not defined for all games. In addition, it does not satisfy another possible desirable property called aggregate monotonicity (i.e. if the value of the grand coalition increases while all other coalitions remain the same, then no generator should get less than before) as well as not necessarily satisfying individual rationality (Hoougard, 2009).

We apply the Shapley value in our Model Results section given its desirable properties and ease of calculation for games with a small number of generators, as is invariably the case with REZs.

Model Results

In any REZ, the final plant capacity that enters $(r, h \in R)$ and the entry timing of that capacity $(t \in T)$, is inherently uncertain. However, Fig.3 provides sufficient approximate information to enable the determination of a fair and efficient allocation of connection costs by entrant and by location, that is, our Shapley values.

Determining Shapley values and final REZ user charges

Recall from the Fig.3 line diagram the Central Queensland REZ is planned by a benevolent transmission planner on the premise of three anchor tenants (generators A, B and C) at two locations (i.e. Substations #1 and #2) – with entry expected in *comparatively* quick succession. Latter entrants are also envisaged at Substation #3 (generator D) and at Substation #2 (generator E, battery F), with entry timing uncertain.

In our Fig.3 line diagram, recall the $40m extension to the existing substation, new Line #1 at $200m and new Substation #1 at $60m – totalling $300m – represent common or 'core' infrastructure to all coalition members of the REZ. Our 4th principle (in Section 3.5) noted any solution needs to adhere to a broader 'capacity to pay' principle. A generator's *capacity to pay* transmission connection costs is a complex area and worthy of a research article in its own right. For our purposes, we rely on the work of Aurecon (2025) which suggests connection capital costs of ~10%.

For this reason, we allocate 50% of the core capital costs (i.e. Line #1, Substation #1 and modifications to the Existing Substation) to each expected coalition member regardless of technology and final topology (i.e. 50% of $300m = $150m). These fixed charges appear in Col.1 of Tab.3.

This leaves residual REZ capital costs of $530m to be allocated to coalition members by way of Shapley values (column c, Tab.3). The next best stand-alone alternative for each project is presented (column d). Note each coalition member is materially better off. Annual user charges (at 10% of the allocated REZ asset values, expressed in $m pa) are presented in column e.

Generator cost allocations (Fixed plus Shapley Value vs Best Alternative)

	Coalition Member	Fixed	Shapley	Total	Best Alt.	Annual Chg
		$m	$m	$m	$m	$m pa
		a	b	a +b = c	d	e
1	Anchor A & B Wind+Solar	50	38	88	300	9
2	Anchor C Wind	25	148	173	425	17
3	Entrant D Wind	25	198	223	350	22
4	Entrants E & F Solar+Battery	50	148	198	400	20
		150	530	680	1475	68

Given these results, we can now proceed with the REZ Optimisation Model under an array of different access and portfolio entry timing scenarios.

Optimal mix of renewables with perfect entry

Implicit in the calculations outlined in Section 4.1 was assumed knowledge of the set of 'expected' connecting generators (per Fig.3 line diagram). This in turn requires that we identify the optimal mix of renewable plant. In doing so, we commence REZ Optimisation Model simulations under conditions of *perfect entry*, that is, where all five wind and solar projects enter simultaneously, with latter entrant projects (Projects D-F in Fig.3) being perfectly divisible in MW capacity.

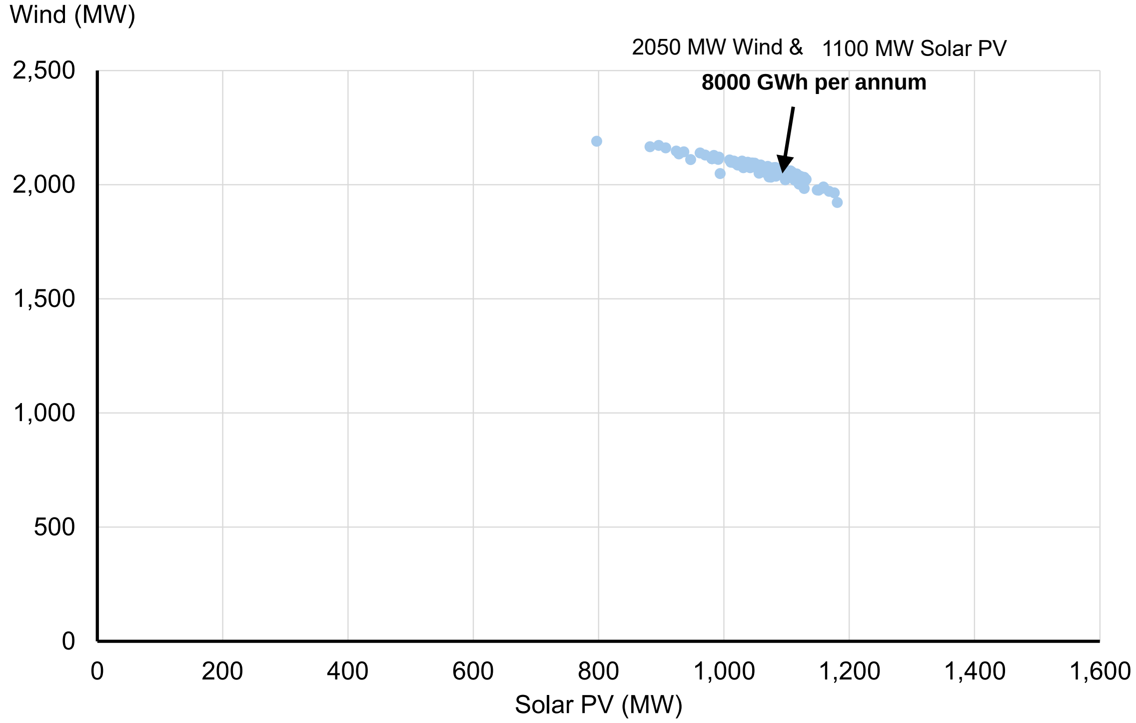
Entry is assumed to occur under conditions of the NEM's 'Open Access' regime, meaning renewable plant curtailment in any trading interval is shared amongst coalition members on a volume-weighted basis. Finally, note in this first round we limit entry to wind and solar PV only. This assumption will be relaxed in Section 4.3 by introducing batteries.

We noted earlier that some level of congestion (i.e. renewable plant curtailment) is efficient inside a REZ. In practice, renewable project investors (equity) and project banks (debt) will – understandably – apply *'tolerable limits'* to curtailment. Recall the REZ Optimisation model includes a variable for this purpose, viz. the curtailment constraint (δ_r) in Eq.(4). For our purposes, we have set (δ_r) to $\ngtr$ 5.25% for wind entrants and $\ngtr$ 8% for solar PV entrants, consistent with the assumptions in Simshauser and Newbery (2024) and Simshauser (2025).

Together with all other data inputs from Section 3, the REZ Optimisation Model runs through 100 iterations. We run 100 iterations due to the nonlinearity of the problem and due to the non-smooth nature of certain constraints, we rely on an evolutionary algorithm to find optimal solutions. Note that because an optimal solution is not guaranteed (unlike with Linear Programming) we run the algorithm a number of times (100x) and store the output of each iteration (of the 100 algorithm simulations) to analyse the different solutions the evolutionary algorithm produces. To improve optimality, after each iteration, we run a generalised reduced gradient nonlinear solver to improve the solution obtained by the evolutionary algorithm. In exploring the space of optimal solutions, we set a range of possible generation values for New Entrant Wind and New Entrant Solar from 400 MW to 1000 MW and 250 MW to 1000 MW respectively (i.e. selected as credible maximum ranges given REZ transfer capacity outlined in Table 1), with iterations exploring generation values between these two ranges in order to analyse this variable's impact on the objective function of the model.

Consequently, as results illustrate in Fig.5, there are multiple credible equilibria arising, due to the diversity of wind and solar resources (and dynamic merit-order spot price impacts) across the five entrant projects. While all combinations are credible, our preferred result with the highest output level is highlighted, at 2050 MW of wind and 1100 MW of solar PV, which produces ~8000GWh per annum. At this point, both wind (5.25%) and solar (8.0%) curtailment limits (δ_r) were binding.

Optimal wind and solar PV in the Central Queensland REZ

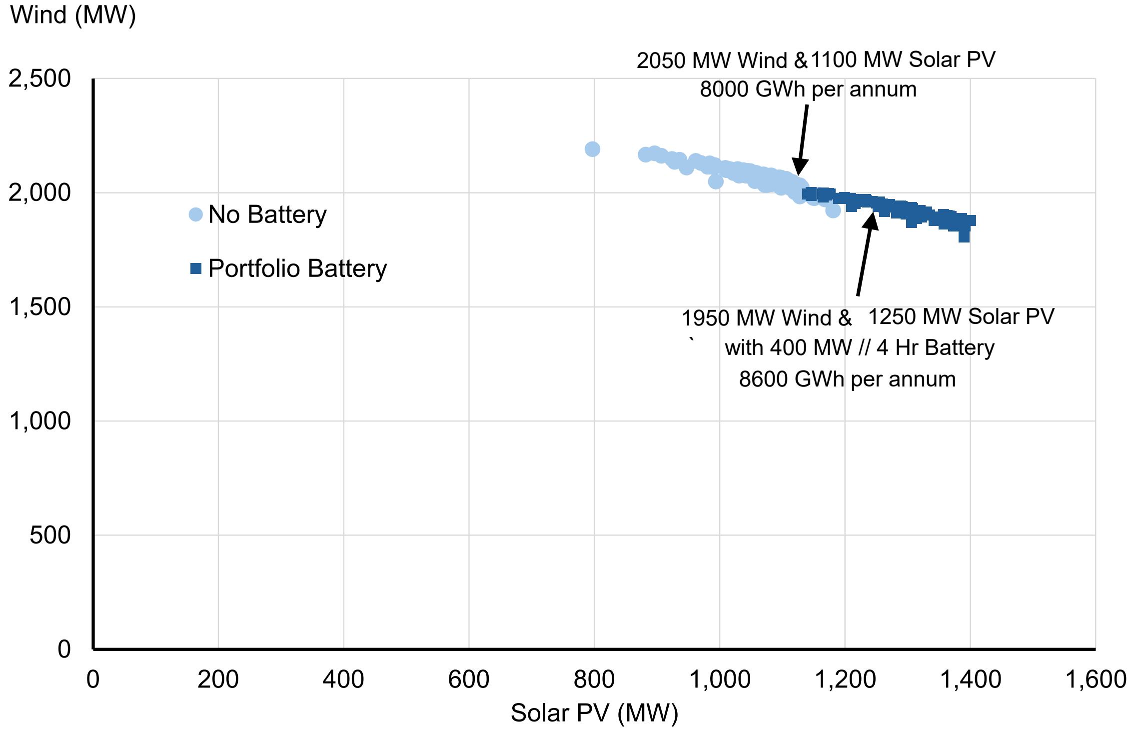


Adding battery storage with perfect entry

Our next set of simulation iterations contrasts the results from Section 4.2 (no storage) with battery storage added. In the Model, we provide a range of battery options comprising 200-600 MW of capacity, with 2-4 hours of storage, consistent with the observed (2000+MW) battery entrants in the Queensland region.

In our first pass of simulation results, we allowed the model to identify the optimal size of the 'Entrant F' Battery (see Fig.3). While a range of capacity (MW) results emerged spanning 250-590 MW, the average was 400MW, with 4 hours storage being consistently preferred. In a second pass of simulation results, in a Stackelberg sequence we committed to a fixed 400MW, 4 hours battery and then allowed the model to solve the optimal mix of renewables (noting in practice, battery development times are considerably faster than wind and solar). Results are presented in Fig.6.

Optimal wind, solar and battery capacity in the CQ REZ



The striking feature of the comparative results in Fig.6 (i.e. no battery vs portfolio battery) is the broadly linear shift in the renewable plant stock, involving slightly less wind in exchange for more solar. This result is not unexpected – solar PV has a lower unit cost, and therefore a battery prefers to '*shift intermittent solar energy through time'* over wind.

Across the 100 iterations, the optimal result involving a 400 MW // 4 hour battery had the effect of reducing wind by -100 MW, and increasing solar PV by 150 MW, with a commensurate increase in output to ~8600 GWh per annum. The plant mix is largely constrained by the curtailment (δ_r) limit in Eq.(4). When this curtailment limit is relaxed by 1 percentage point, the model opts for additional solar capacity (150MW) with no change in wind.

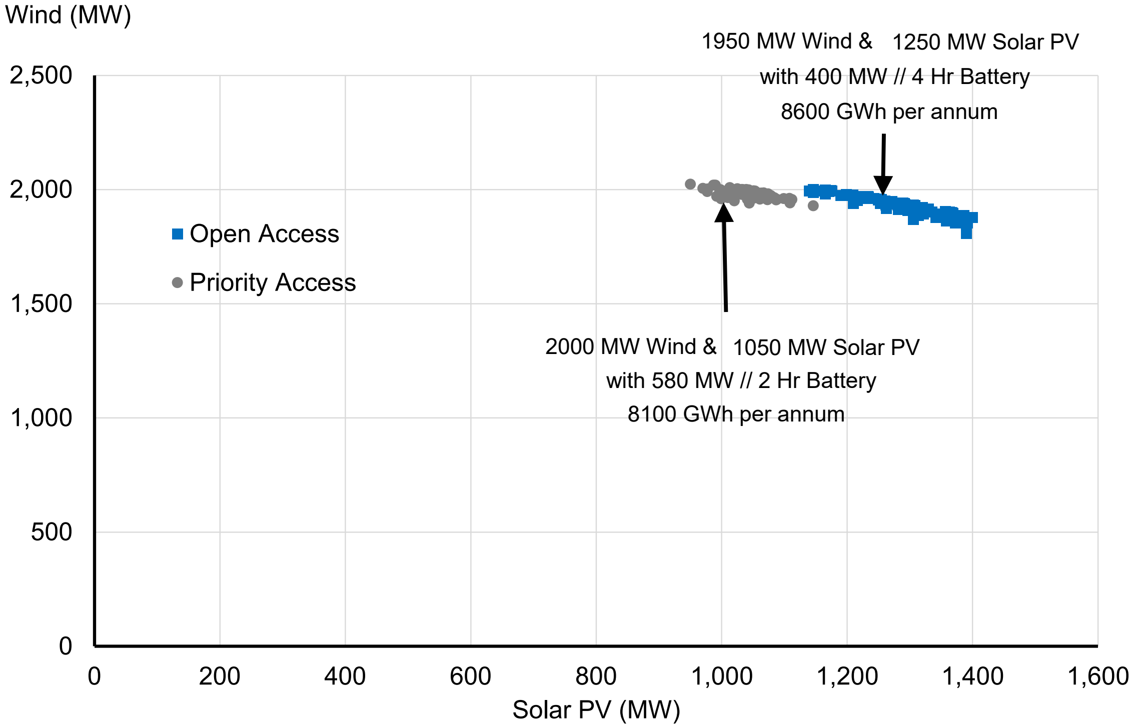
Perfect entry and Access Regimes: Open vs Priority Access

One line of inquiry which has been persistent amongst Australian policymakers is whether the NEM's 'Open Access' regime – whereby any generator may connect to the transmission upon satisfying technical requirements – is workable in the long run. The primary concern here is that in the absence of *'allocated transmission rights'* within a REZ (as occurs in nodal markets through financial transmission rights), renewable entrants may vastly exceed REZ transmission line transfer capacity, leading to financially destructive levels of congestion and curtailment for incumbent renewable generators who invested in good faith – and caused by the actions of *the last entrant* who created the excess congestion event. There are two reasons why an alternate model of 'Priority Access' in the NEM – where connecting generators are allocated or acquire transmission rights – is unhelpful.

First, the premise that entry will vastly exceed REZ transfer limits assumes the marginal investor is technically (and financially) incompetent, incapable of identifying congestion risk, and not constrained by the due diligence processes of project banks (debt) and utility or institutional investment committees (equity). Occasional entry failures in the NEM do occur, but when they do, they are invariably high-profile events. The practical experience from Australia is that it takes just one poorly located generator entrant in the NEM to trigger a rapid recalibration of due diligence processes, screening tests and lending covenants by project banks (not to mention equity investor reactions). The array of consequences (i.e. congestion, rapidly falling marginal loss factors – the NEM's locational or nodal spot price multiplier and primary locational signal) ensures this is the case.

Second, as the set of comparative iterations in Fig.7 and Tab.4 subsequently illustrate, priority access with a fleet of intermittent renewable generators is *not* welfare enhancing (a result consistent with Simshauser and Newbery 2024).

Open Access vs Priority Access



In Fig.7, Open Access iterations with a portfolio battery per Eq.(8) are compared to 'Priority Access' iterations with a rival battery per Eq.(7). To summarise, the optimal plant mix under Priority Access results in, on average, a 50MW increase in wind, and a 200 MW decrease in solar PV. Furthermore, in Priority Access iterations, the model universally prefers 2-hour duration batteries, with close to maximum battery capacity at 580MW (noting the limits were set to 200-600 MW, and 2-4 hours).

At one level, Priority Access gives incumbent investors greater certainty since the aggregate level of congestion and lost output (5%) will always be lower than in an Open Access regime (7%). However, from a policy perspective what matters are the welfare implications, which are clearly set out in Tab.4 – with the full data set in Appendix III.

Welfare changes in Open vs Priority Access

		Open vs Priority Access ($ Million pa)
1	Chg in Consumer Surplus	346.6
2	Chg in Producer Surplus (Wind)	-15.2
3	Chg in Producer Surplus (Solar)	63.1
4	Gross Chg in RE Producer Surplus (2+3)	47.9
5	*Lost Economic Profits* (Priority Access)	-14.7
6	Net Chg in RE Producer Surplus (4+5)	33.2
7	Change in Total Welfare (1+6)	379.8

As Tab.4 illustrates, when contrasting Open Access with Priority Access, consumer surplus rises by $346.6m per annum (Line 1), largely driven by REZ productivity (nb. higher output levels with an Open Access regime). Producer surplus expands by $33.2m in aggregate (Line 6) but involves wealth transfers amongst generators since economic profits of early entrants will be lower (Line 5. -$14.7m). But in aggregate, welfare is maximised and $379.8m per annum higher under Open Access than Priority Access.

REZ Investment under uncertainty: imperfect entry

Recall from Section 1 that in the NEM's Queensland region, REZ are *market led* and merchant, meaning they are ultimately underwritten by connecting renewable generators. Throughout Sections 4.1-4.4, entry was assumed to be perfect and generator connection costs were optimal. The optimal mix of generation entered simultaneously and the REZ was, in turn, fully subscribed. Under these conditions, the task of the benevolent transmission planner was a simple one. However, renewable plant entry in the real world bears no resemblance to these highly idealised conditions. Even with clearly articulated Shapley values, entry and entry timing is uncertain:

- The task of banking a single renewable project takes several years of development, culminating in the simultaneous execution of multiple (highly complex) legal documents involving primary plant supply from Original Equipment Manufacturers, Balance of Plant suppliers and transmission connection (which in turn follows environmental and local government approvals, transport movement approvals, allocation of water rights during construction), and in the process of coordinating these – holding a Power Purchase Agreement in place while the critical constraint – project finance (banks) and equity commitment (investment committees) are completed. Holding this 'web of contracts' in place for more than 6-8 weeks often proves intractable.

- Consequently, the notion that an entire coalition of renewable projects in the same REZ area could achieve financial close, simultaneously, is implausible. Indeed, two sequentially located projects reaching financial close in the same month would be highly irregular in Australia's NEM.

- More likely, project proponents will target a certain month to reach financial close and will almost always run 6+ months behind the target date despite best efforts – because the banking of any power project is exceedingly difficult.

How then does a benevolent transmission planner proceed with a REZ under uncertainty? In the Queensland case, there are five guiding parameters:

1. Anchor tenant(s) need to be of significant scale to warrant REZ investment commitment; and

2. The investment quality and track record of (near-term) *latter entrants* needs to be understood, with evidence of extensive sunk development; and

3. Some level of *structured finance* which has the effect of reorganising the timing of REZ cashflows becomes essential (see Simshauser, 2021); and

4. The benevolent transmission planner must be prepared to warehouse some level of (transient) idle REZ transmission hosting capacity; and

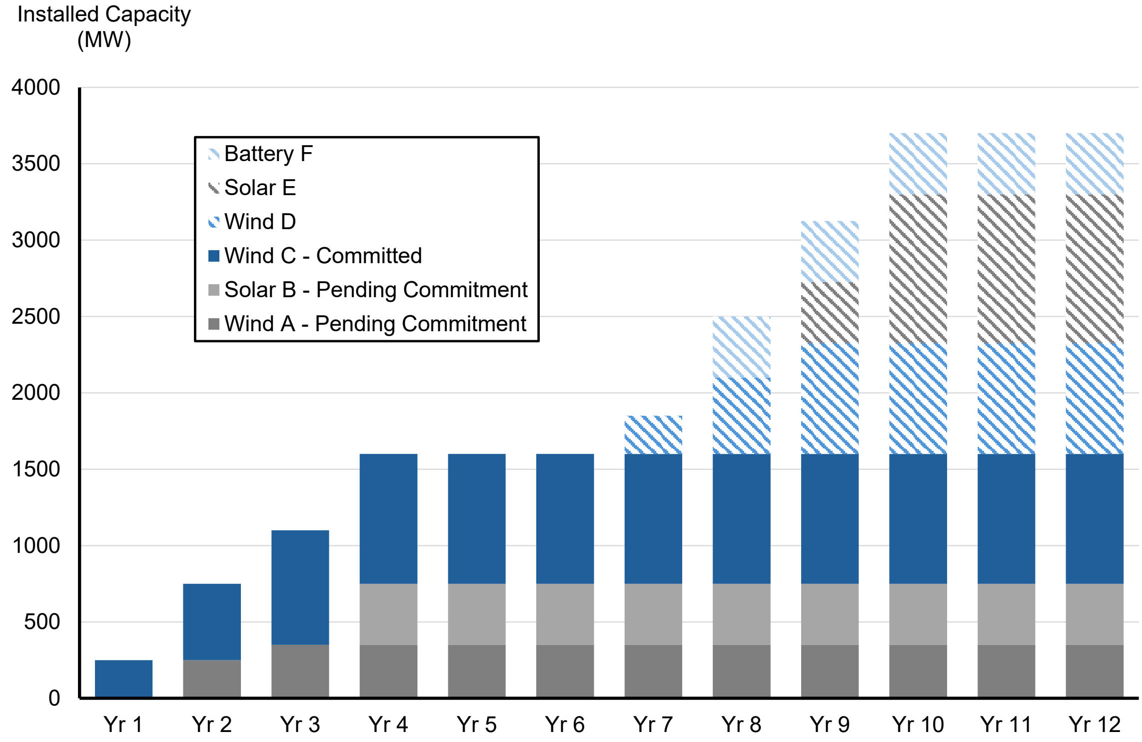
5. Ultimately, a backstop mechanism is required – the ability to recover some level of idle REZ hosting capacity through a regulatory rate case (i.e. as a regulated con-

sumer charge) should distances and resulting investment costs breach renewable generators' *capacity to pay*.

Anchor tenants

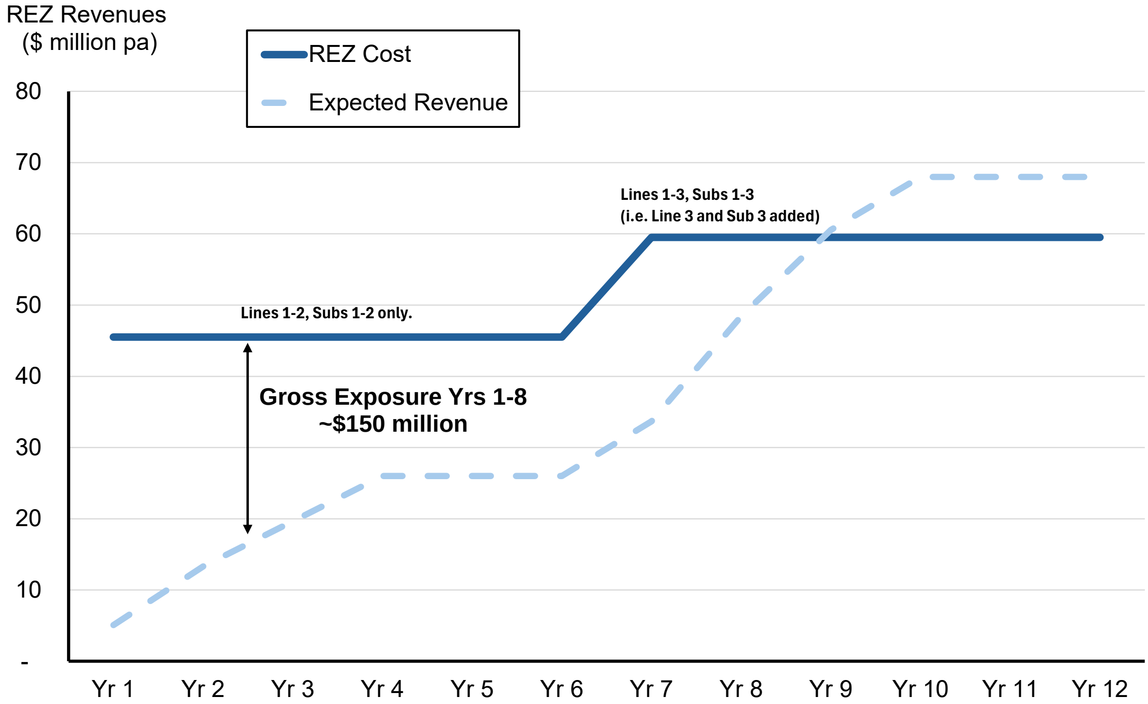
In the analyses that follow, we introduce imperfect entry outlined in Fig.8. Entry timing could be modelled as a stochastic process with associated probabilities, but to begin with, we use a fixed entry schedule to illustrate the problem.

Committed vs Expected Entry



It is apparent from Fig.8 with only Project C being committed, and Projects A and B pending commitment as at Year 1 (i.e. with Projects A-B expected to reach financial close during Yr 1, with 1-2 year construction lag). At the same time, Line #3 and Substation #3 do not need to be built until Project D commits (in Year 6). Regardless, even with the delayed construction of Line #3, imperfect entry means a gap exists between the annual REZ Cost and Expected Revenues during Years 1-8. This is illustrated in Fig.9. Note from Fig.9 the initial exposure from years 1-8 amounts to \$150m given the entry schedule in Fig.8. From Year 10 onwards, Expected Revenues exceed REZ Costs at the rate of ~\$8m per annum. However, this latter-period premium is not sufficient to recover the initial loss of \$150m. In other words, the transmission planner appears to face a negative NPV project. If we were to introduce additional uncertainty over entry timing, it would further compound the benevolent transmission planner's level of financial exposure. At this point, the entire REZ program would stall.

Revenue implications of uncertain entry timing



There are three plausible solutions to the problem outlined above:

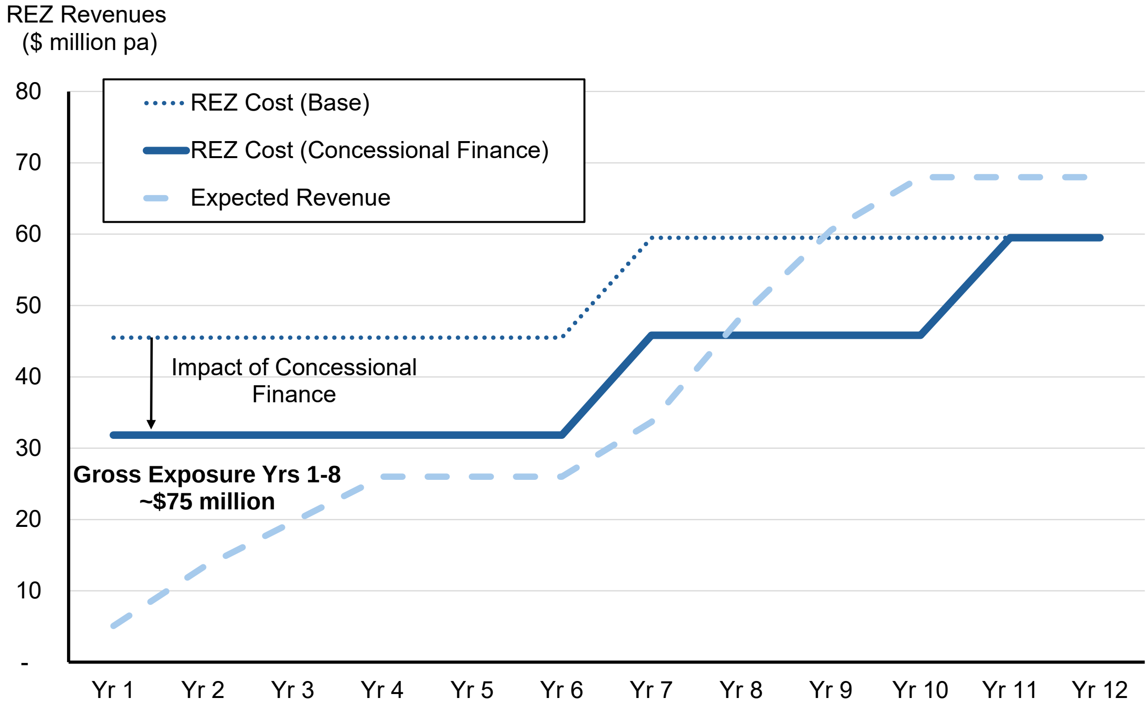
1. User charges could be uniformly increased by ~10%. This would ensure losses incurred during Yrs 1-8 would be recovered over the remaining useful asset life;
2. Deploy concessional finance; or
3. Allocate some element of the REZ asset base to the broader (consumer-funded) Regulatory Asset Base (RAB).

The impact of concessional finance

In various jurisdictions, renewable finance agencies exist which provide concessional debt facilities to reduce the costs of the so-called energy transition. In Australia, the Commonwealth Government set up the Clean Energy Finance Corporation (CEFC) for this purpose. Under certain conditions the CEFC may issue concessional debt facilities. When applied to a REZ, the level (and/or) timing of cash flows are re-organised. Here, we demonstrate the impact of a 10-year concessional debt facility set within a semi-permanent structure[3] with a 300 basis point discount. When applied, REZ Costs drop from ~$46m to ~$32m during the first 10 years. Applying these conditions to the problem outlined in Fig.9 (i.e. Gross Exposure of $150m) has the effect of reducing the Gross Exposure to $75m. Given premium rents are expected to be earned from Yr 10 onwards (i.e. Expected Revenues > REZ Cost), initial losses are more than offset over time, meaning the benevolent transmission planner's project is now NPV positive.

[3] Semi-permanent debt structures involve longer tenors (e.g. 5-10 years) than mini-perm (3-5 years) facilities. Both involve principal repayments according to a set schedule (e.g. nominal 30-year repayment) with a balloon payment for the outstanding balance at the end of the loan tenor. Balloon payments ultimately involve debt refinancing.

Impact of structured finance



REZ costs exceeding the *capacity to pay* under perfect entry

The concept of merchant REZs is based on the principle that transmission investment costs may be recovered from connecting generators. What happens if system-wide analysis suggests a REZ investment program is NPV positive, but REZ user-charges exceed the coalition of market generators' *capacity to pay*? Conversely, what if the entry timing of the coalition is so uncertain that a benevolent planner baulks at the initial merchant exposure? Either scenario suggests being NPV positive, and therefore welfare maximising in aggregate, the REZ investment program should proceed, with the gap covered through some other set of charges.

Recall from Section 4.1 we identified NEM generator 'capacity to pay' translates to ~10% of committed capital (i.e. a $3 billion wind farm could underwrite ~$300 million of REZ investment costs and associated user charges). In our scenarios thus far, total REZ user charges of $68 million per annum were comfortably within this 'capacity to pay' limit (while not defined explicitly, the aggregate 'capacity to pay' result is ~$85 million pa based on Projects A-F). In Section 4, no financial losses were incurred by the transmission planner because perfect entry meant simultaneous entry on day 1 – which is not credible. In Section 5.2, staggered entry led to transient idle losses (Fig.9), and these were able to be offset through a concessional debt financing facility (Fig.10). But what if REZ investment costs and associated user charges meet or exceed the aggregate capacity to pay limit of $85 million per annum?

In our final scenario, we assume the distances of Transmission Lines 1, 2 and 3 are extended such that total REZ investment costs equate to $890 million and implied user charges rise to $89 million per annum – which breaches the generators' capacity to pay limits – particularly for Entrants D, E and F as Table 5 illustrates – by ~$83 million (lines 3-4, columns c vs d). Consequently, if the overall REZ transmission infrastructure and coalition of generators are welfare maximising, then this residual asset of $83 million may be most efficiently dealt with by adding it to the benevolent transmission planner's Regulatory Asset Base or 'RAB', as illustrated in Table 5 (Line 5).

The intuition underpinning 'RAB allocation' is as follows. First, given the REZ and coalition of generators are assumed to have exhausted any supernormal profits and represent a welfare maximising combination of assets, then the REZ investment should proceed with the key issue being how the $83 million 'residual' should be recovered. Two options exist, (1) increase the entry costs of Entrants D, E and F, or (2) allocate the residual to the RAB. Option (1) raises the weighted entry cost of wind and solar by ~$4/MWh and if this became the market clearing price for new renewable projects in a 55TWh system like Queensland, consumer costs would rise by ~$200 million pa. By allocating the residual to the RAB, Option (2) raises consumer costs by just $8 million per annum as Table 5 (line 5, column f) illustrates.

REZ asset allocation to Regulatory Asset Base under perfect entry

	Coalition Member	Fixed	Shapley	Sub-Total	Limit*	Total	Annual Chg
		$m	$m	$m	$m	$m	$m pa
		a	b	a +b = c	d	Min (c , d) = e	f
1	Anchor A & B Wind+Solar	75	56	131	165	131	13
2	Anchor C Wind	38	186	224	255	224	22
3	Entrant D Wind	38	236	*274*	240	*240*	24
4	Entrants E & F Solar+Battery	75	186	*261*	212	*212*	21
5	Allocate to RAB**			*Lines 3-4, ∑(c - d) = $83m --->*		83	8
	*Limit = *Capacity to Pay*	225	665	890		890	81
	**RAB = Regulatory Asset Base						

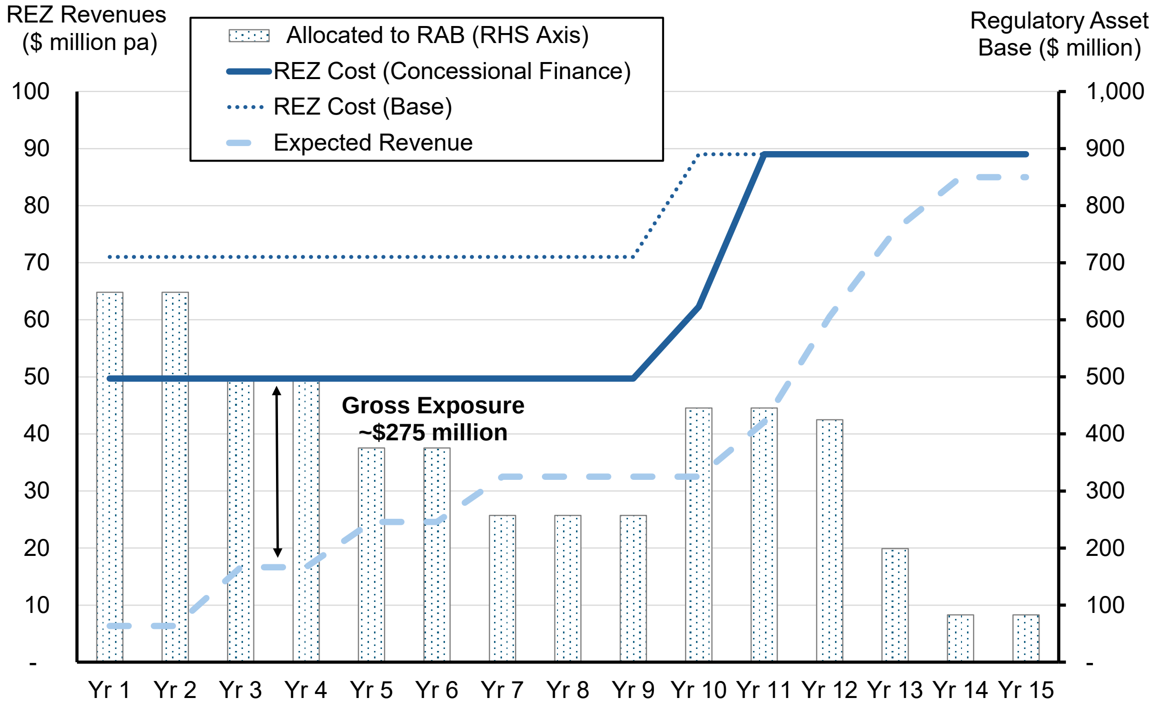
REZ costs, capacity to pay and imperfect entry

Recall from Section 5.3 that $83 million of REZ assets need to be allocated to the transmission planner's RAB. This covers the gap between the REZ Cost, and the coalition of renewable generators (binding) capacity to pay under conditions of perfect entry.

What happens when REZ costs are high, <u>*and*</u> entry timing is *uncertain*. Figure 11 identifies the shortfall and the mechanism for its resolution. First, note REZ Cost (Base) commences at $71m for years 1-9, as represented by the dotted line. The REZ Cost reflects the partial REZ assets developed (Lines 1-2, Subs 1-2) at the new and higher construction cost of $710 million. From Year 10, REZ assets step up in value with Line 3 and Sub 3 constructed following commitment by Wind Entrant D. At this point, REZ Cost rises to $89 million per annum.

Next, concessional finance is applied. A 10-year semi-permanent facility reduces the REZ Cost to ~$50m per annum, thus lowering the Gross Exposure to $275 million. At this level of exposure, the benevolent transmission planner may not proceed despite our assumption that the REZ is a system-wide beneficial program of investment. For the transmission planner to revert to a risk neutral state, some level of REZ assets may be allocated to the RAB on a transient basis (see bar series, RHS axis in Fig.11). As REZ assets are deployed, connecting generators pay their user charges and any transient shortfall is then allocated to the RAB (rising bars). As entrants commit and user charges commence (dash line series), a portion of REZ assets may be withdrawn from the RAB (falling bars). In effect, transient idle capacity is carried in the RAB until its entry is committed.

REZ costs, capacity to pay and entry under uncertainty



Policy implications

REZ are an important policy initiative for Australia's NEM and their successful development is important to minimise the cost of the energy transition, and to navigate the challenges and constraints associated with communities, the environment and cultural heritage. REZs are designed to coordinate multiple renewable projects and minimize marginal transmission costs, all of which is crucial given transmission is costly and community, environmental and cultural sensitivities are involved.

Different NEM states have adopted different approaches to REZs. Queensland opted for a merchant model, where connecting generators pay user charges – which in turn enabled rapid deployment by bypassing regulatory lag. However, a model of this nature would inevitably meet structural challenges, specifically, a requirement for multiple connecting projects to effectively underwrite transmission augmentations in the presence of entry under uncertainty. Furthermore, there is ultimately a supply curve of REZs, and like all supply curves, it is upwards sloping. This implies that the absolute cost of future REZs – necessarily extending further away from the transmission backbone – will be rising in cost and will ultimately breach the limits of renewable generators' capacity to pay.

To navigate what are predictable challenges, we examined a basis upon which to allocate REZ costs and associated user charges amongst a coalition of connecting generators, bounded by their capacity to pay. The Shapley value method, a concept from cooperative game theory, was used for this purpose and in doing so, was able to define fair and defendable user charges. As a policy mechanism the method has several desirable properties, including individual rationality, efficiency, symmetry, and monotonicity

If a REZ development encounters conditions of acute entry under uncertainty, or costs that exceed the reasonable level of generators' capacity to pay due to longer distances involved, combinations of concessional finance and allocation to the Regulatory Asset Base provide pathways to facilitate a benevolent transmission planners' welfare maximising program of investment to proceed. Allocation to the Regulatory Asset Base may well be transient, as initial idle transfer capacity is gradually absorbed by latter entrant generators.

Conclusion

Development of REZ in Australia's NEM represents a critical policy initiative aimed at facilitating the energy transition in an efficient manner. REZ are designed to coordinate multiple renewable projects that would otherwise act independently, thereby minimizing marginal transmission costs, and the various community, environmental, and cultural sensitivities associated with large-scale infrastructure development.

Queensland's approach to REZ development, characterized by a merchant model, has enabled rapid deployment of renewable projects with its distinctive feature being that connecting generators underwrite the capital cost through user charges. This model has proven effective in accelerating the development of REZs, with several projects operational within a period of 4 years from start to finish.

However, the merchant model presents significant challenges vis-à-vis cost allocation and financial tractability as REZs extend further away from the transmission backbone. The complexity of coordinating multiple projects with varying timelines and locations necessitates a fair and efficient method for allocating costs among generators. The application of the Shapley value method provides a robust solution for defining fair user charges based on the individual contributions of each wind or solar producer to the coalition of REZ-connected generators.

When renewable entry is perfect and REZ distances are small, investment commitment by a risk neutral benevolent transmission planner is clear cut. When entry under uncertainty is introduced, user charges may fall short of REZ Costs. Similarly, as REZ distances are extended from the transmission backbone, the capital costs rise, and user charges may exceed generators' reasonable capacity to pay. Use of concessional finance, and transient allocation of capital to the Regulatory Asset Base may provide a mechanism to ensure continuity of timely REZ investments – noting network hosting capacity is a precondition for renewable project entry.

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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 – PCF Model Inputs

Table A1: Plant Technical & Cost Assumptions (pre-REZ costs)

Generation Technology		Wind	Solar	Battery
Project Capacity	(MW)	1,000	400	200
- Storage Capacity	(Hrs)	-	-	4
Overnight Capital Cost	($/kW)	3,300	1,500	525
- Storage	($/kWh)	-	-	380
Plant Capital Cost	($ M)	3,300	600	409
Operating Life	(Yrs)	35	30	20
Annual Capacity Factor	(%)	33.0%	27.2%	14.7%
Transmission Loss Factor	(MLF)	0.990	0.970	1.000
Transmission REZ Costs	($/MW/a)		*Modelled*	
Fixed O&M	($/MW/a)	25,000	20,000	10,000
Variable O&M	($/MWh)	0.0	0.0	0.0
FCAS	(% Rev)	-1.0%	-1.0%	4.0%

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 A2: Project Finance Parameters

Project Finance		
Debt Sizing Constraints		
- DSCR	(times)	1.8
- Gearing Limit	(%)	0.4
- Default	(times)	1.05
Project Finance Facilities - Tenor		
- Term Loan B (Bullet)	(Yrs)	5
- Term Loan A (Amortising)	(Yrs)	10
- Notional amortisation	(Yrs)	15
Project Finance Facilities - Pricing		
- Term Loan B Swap	(%)	4.09%
- Term Loan B Spread	(bps)	180
- Term Loan A Swap	(%)	4.19%
- Term Loan A Spread	(bps)	209
- Refinancing Rate	(%)	6.1%
Expected Equity Returns	(%)	8.0%

Balance Sheet Financing			
Credit Metrics (BBB Corporate)		Merch	Reg.
- FFO / I	(times)	4.2	2.4
- Gearing Limit	(%)	40.0	65.0
- FFO / Debt	(%)	20%	9%
Bond Issues			
- 5 Year	(%)	5.45%	
- 7 Year	(%)	5.59%	
- 10 Year	(%)	5.65%	
Commonwealth Bonds			
- 10 Year	(%)	4.14%	
Expected Equity Returns	(%)	10.0%	

Source: Gohdes (2022, 2023), Bloomberg.

Appendix III – PCF Model Logic

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

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

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.

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

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:

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

If thermal plants 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'[4] 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.

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

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.

$$FOM_j^i = FC^i . k^i . \pi_j^C, \quad (5)$$

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

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

[4] 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:

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

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 $\left(I_j^i\right)$ 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 $\left(X_0^i\right)$. 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).

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

Credit metrics[5] $\left(\delta_j^{VI}\right)$ and $\left(\omega_j^{VI}\right)$ 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 $\left(p^{i\varepsilon}\right)$ 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:

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

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

Let $IRR \equiv K_e$

[5] 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.

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

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

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

Appendix III - Open vs Priority Access

Table a1 – Open Access

	Wind	1,925 MW	2018	2019	2020	2021	2022	2023	2024	TOT/AVG
1	Potential Wind Output	(GWh)	6,015	5,920	5,616	5,691	5,803	5,496	2,690	37,230
2	Practical Wind Output	(GWh)	5,868	5,784	5,524	5,593	5,681	5,396	2,638	36,486
3	REZ Congestion	(GWh)	146	136	91	97	122	100	52	744
4	Energy Curtailed	(% of Prod)	2.4%	2.3%	1.6%	1.7%	2.1%	1.8%	1.9%	2.0%
5	Economic Wind Output	(GWh)	5,866	5,709	5,326	5,331	5,484	4,939	2,435	35,088
6	Spill -ve spot prices	(GWh)	3	76	199	263	197	457	204	1,398
7	Energy Spilled	(%)	0.0%	1.3%	3.7%	4.9%	3.6%	9.3%	8.4%	4.0%
8	Total Curtail & Spill	(GWh)	149	211	290	360	320	557	255	2,142
9	Total Curtail & Spill	(% of Prod)	2.5%	3.6%	5.2%	6.3%	5.5%	10.1%	9.5%	5.8%
10	Potential ACF	(% - ACF)	35.7%	35.1%	33.2%	33.7%	34.4%	32.6%	32.0%	33.8%
11	Economic ACF	(% - ACF)	34.8%	33.9%	31.5%	31.6%	32.5%	29.3%	29.0%	31.8%
12	ACF Loss	(% - ACF)	0.9%	1.3%	1.7%	2.1%	1.9%	3.3%	3.0%	2.0%
13	Revenue	$m	531.3	512.5	285.7	573.3	884.5	571.2	301.7	3,660.3
14	Costs (incl. REZ)	$m	531.9	532.5	534.0	532.5	532.5	532.5	265.5	3,461.5
15	Economic Profit	$m	-0.6	-20.0	-248.3	40.8	352.0	38.7	36.2	198.8
16	Unit Revenue	($/MWh)	90.6	89.8	53.6	107.6	161.3	115.7	123.9	104.3
17	Unit Cost	($/MWh)	90.7	93.3	100.3	99.9	97.1	107.8	109.1	98.7
18	Economic Profit	($/MWh)	-0.1	-3.5	-46.6	7.7	64.2	7.8	14.9	5.7
	Solar PV	**1,375 MW**	2018	2019	2020	2021	2022	2023	2024	TOT/AVG
19	Potential Solar Output	(GWh)	3,354	3,460	3,298	3,227	3,130	3,314	1,474	21,257
20	Practical Solar Output	(GWh)	3,267	3,381	3,246	3,173	3,050	3,255	1,442	20,815
21	REZ Congestion	(GWh)	87	78	52	55	79	58	33	443
22	Energy Curtailed	(% of Prod)	2.6%	2.3%	1.6%	1.7%	2.5%	1.8%	2.2%	2.1%
23	Economic Solar Output	(GWh)	3,259	3,219	2,866	2,631	2,619	2,078	1,093	17,763
24	Spill -ve spot prices	(GWh)	9	163	380	542	432	1,178	349	3,052
25	Energy Spilled	(%)	0.3%	5.1%	13.3%	20.6%	16.5%	56.7%	31.9%	17.2%
26	Total Curtail & Spill	(GWh)	96	241	432	597	511	1,236	381	3,495
27	Total Curtail & Spill	(% of Prod)	2.9%	7.0%	13.1%	18.5%	16.3%	37.3%	25.9%	16.4%
28	Potential ACF	(% - ACF)	27.2%	28.1%	26.9%	26.3%	25.3%	27.0%	24.0%	26.4%
29	Economic ACF	(% - ACF)	27.1%	26.7%	23.7%	21.8%	21.7%	17.2%	18.2%	22.4%
30	ACF Loss	(% - ACF)	0.1%	1.4%	3.1%	4.5%	3.6%	9.8%	5.8%	4.0%
31	Revenue	$m	287.5	253.4	128.2	181.7	233.9	141.5	76.6	1,302.8
32	Costs	$m	191.1	191.3	191.8	191.3	191.3	191.3	95.4	1,243.5
33	Economic Profit	$m	96.4	62.1	-63.6	-9.6	42.6	-49.8	-18.8	59.3
34	Unit Revenue	($/MWh)	88.2	78.7	44.7	69.1	89.3	68.1	70.1	73.3
35	Unit Cost	($/MWh)	58.6	59.4	66.9	72.7	73.1	92.1	87.3	70.0
36	Economic Profit	($/MWh)	29.6	19.3	-22.2	-3.6	16.3	-24.0	-17.2	3.3
37	Portfolio Output (Line 5+23)	(GWh)	9,124	8,927	8,191	7,961	8,102	7,017	3,528	52,851
37	Portfolio Profit (Lines 15+33)	$m	29.5	15.8	-68.8	4.0	80.4	-16.2	-2.3	9.0

Table b1 – Priority Access

	Wind	1,975 MW	2018	2019	2020	2021	2022	2023	2024	TOT/AVG
1	Potential Wind Output	(GWh)	6,170	6,074	5,761	5,839	5,954	5,639	2,758	38,195
2	Practical Wind Output	(GWh)	6,056	5,967	5,687	5,761	5,858	5,563	2,716	37,607
3	REZ Congestion	(GWh)	115	107	75	78	96	76	42	588
4	Energy Curtailed	(% of Prod)	1.9%	1.8%	1.3%	1.3%	1.6%	1.4%	1.5%	1.5%
5	Economic Wind Output	(GWh)	6,053	5,886	5,481	5,487	5,650	5,083	2,504	36,143
6	Spill -ve spot prices	(GWh)	3	81	206	274	208	480	212	1,464
7	Energy Spilled	(%)	0.0%	1.4%	3.8%	5.0%	3.7%	9.4%	8.5%	4.1%
8	Total Curtail & Spill	(GWh)	118	188	280	352	304	556	254	2,052
9	Total Curtail & Spill	(% of Prod)	1.9%	3.1%	4.9%	6.0%	5.1%	9.9%	9.2%	5.4%
10	Potential ACF	(% - ACF)	35.7%	35.1%	33.2%	33.7%	34.4%	32.6%	32.0%	33.8%
11	Economic ACF	(% - ACF)	35.0%	34.0%	31.6%	31.7%	32.7%	29.4%	29.0%	31.9%
12	ACF Loss	(% - ACF)	0.7%	1.1%	1.6%	2.0%	1.8%	3.2%	2.9%	1.9%
13	Revenue	$m	548.2	528.3	292.9	588.3	908.0	585.3	308.9	3,759.8
14	Costs (incl. REZ)	$m	544.3	544.9	546.4	544.9	544.9	544.9	271.7	3,542.1
15	Economic Profit	$m	3.9	-16.6	-253.5	43.3	363.1	40.3	37.2	217.7
16	Unit Revenue	($/MWh)	90.6	89.8	53.4	107.2	160.7	115.1	123.4	104.0
17	Unit Cost	($/MWh)	89.9	92.6	99.7	99.3	96.5	107.2	108.5	98.0
18	Economic Profit	($/MWh)	0.6	-2.8	-46.3	7.9	64.3	7.9	14.9	6.0
	Solar PV	**950 MW**	2018	2019	2020	2021	2022	2023	2024	TOT/AVG
19	Potential Solar Output	(GWh)	2,318	2,390	2,278	2,230	2,162	2,290	1,019	14,687
20	Practical Solar Output	(GWh)	2,283	2,361	2,261	2,211	2,133	2,268	1,006	14,523
21	REZ Congestion	(GWh)	34	30	18	19	30	22	13	164
22	Energy Curtailed	(% of Prod)	1.5%	1.2%	0.8%	0.8%	1.4%	1.0%	1.2%	1.1%
23	Economic Solar Output	(GWh)	2,277	2,247	1,998	1,836	1,830	1,448	763	12,400
24	Spill -ve spot prices	(GWh)	6	113	263	376	302	820	243	2,123
25	Energy Spilled	(%)	0.3%	5.0%	13.2%	20.5%	16.5%	56.6%	31.9%	17.1%
26	Total Curtail & Spill	(GWh)	40	143	281	394	332	841	256	2,287
27	Total Curtail & Spill	(% of Prod)	1.7%	6.0%	12.3%	17.7%	15.4%	36.7%	25.1%	15.6%
28	Potential ACF	(% - ACF)	27.5%	28.4%	27.1%	26.6%	25.6%	27.3%	24.2%	26.7%
29	Economic ACF	(% - ACF)	27.4%	27.0%	23.9%	22.1%	22.0%	17.4%	18.4%	22.6%
30	ACF Loss	(% - ACF)	0.1%	1.4%	3.2%	4.5%	3.6%	9.8%	5.9%	4.1%
31	Revenue	$m	201.4	177.3	89.6	127.5	163.3	98.5	53.5	911.2
32	Costs	$m	136.4	136.5	136.9	136.5	136.5	136.5	68.1	887.6
33	Economic Profit	$m	65.1	40.8	-47.3	-9.1	26.8	-38.0	-14.6	23.6
34	Unit Revenue	($/MWh)	88.5	78.9	44.9	69.4	89.2	68.0	70.2	73.5
35	Unit Cost	($/MWh)	59.9	60.8	68.5	74.4	74.6	94.3	89.2	71.6
36	Economic Profit	($/MWh)	28.6	18.1	-23.7	-4.9	14.6	-26.2	-19.1	1.9
37	Portfolio Output (Line 5+23)	(GWh)	8,330	8,133	7,478	7,323	7,480	6,531	3,267	48,542
37	Portfolio Profit (Lines 15+33)	$m	29.2	15.3	-69.9	3.0	78.9	-18.3	-4.2	7.9