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Locational and market value of Renewable Energy Zones in Queensland

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Abstract
Efficient coordination in transmission planning and locating variable renewable energy (VRE) generation is important in transitioning to a low carbon electricity system. Renewable Energy Zones (REZ) provide an opportunity to strategically augment and expand the existing transmission network to maximise use the available renewable resources. The Queensland region of Australia's National Electricity Market provides a unique case for analysis, where complementary patterns of wind and solar supply exist across a broad geographical area. This article presents new information about the nine proposed REZ across the region and their utility in supplying energy as the incumbent fleet of baseload generators is forecast to retire. Understanding their locational and market value provides insight into the underlying cost of energy and its ability to satisfy energy demands. The recent entry cost shocks impacting the VRE industry in the post-pandemic recovery have been quantified, where increases of 23-44% to the cost of energy have been observed. These increases have been driven by shifts in the capital and operating costs for new projects, which are compounded by the simultaneous increases to the cost of capital. Real world analysis has occurred to support the modelled outcomes and highlight the value of REZ in Queensland.

Keywords: Renewable Energy Zones; cost of energy; market value.
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1. Introduction

As the pace of the variable renewable energy (VRE) investment super cycle continues and with the rising ambitions of various levels of Government in Australia, the need to streamline and facilitate efficient connection of new projects is crucial. A key component in facilitating new VRE connections is having suitable transmission hosting capacity, to enable generation from the best renewable resources to reach demand centres efficiently. Achieving this growth needs to consider the trade-off between renewable resource (i.e. wind speed, solar irradiation), distance from the main transmission network, nodal supply-demand imbalances, associated losses in transmission – and more recently, community considerations and the 'social licence to operate'. Considerable effort has already been invested in solving some elements of this broader problem in recent years, specifically, how to maximise the utilisation of the vast renewable resources across broad geographic areas of the Australian National Electricity Market (NEM).

One emerging solution with considerable promise is the development of dedicated Renewable Energy Zones (REZ). These developments are intended to augment and expand on existing 'shared transmission network' infrastructure in locations of high value VRE resource. By pursuing economies of scale at the transmission investment level, initial overcapacity introduces an element of financial risk to network service providers, but has the potential to enable multiple renewable generators to enter at scale, reduce the aggregate footprint of the industry (i.e. reducing community impacts and therefore potential opposition to VRE projects), and facilitate a form of co-optimisation of complementary wind and solar resources. Furthermore, when done at locational scale, it should enable participants to overcome emerging issues associated with inverter-based renewable generation (i.e. control system interactions and system strength) through coordinated effort, and to undertake joint or broader zonal environmental approvals. While existing consumer-funded frameworks for investment in the shared transmission network have significant limitations in enabling proactive investment, market-funded approaches in the NEM's Queensland region are being fast tracked to stay abreast of the ever-nearing retirement of large volumes of baseload generating capacity. As the concept of REZs mature, varied approaches to financing are also emerging. At its purest level, a market funded (or merchant) REZ would have project-specific financing and repaid through connection fees from participating generators. In practice however, some jurisdictions are opting for blended approaches where concessional loans backed by the Commonwealth Government (topped up by individual project contributions), allows large portions to be layered into the Regulated Asset Base.

Inherent in its nature, the variability, uncertainty and often remoteness of VRE generation projects require large volumes of capacity to be installed in locations with high quality wind and solar resources. When geographically concentrated within a REZ, the high highs and low lows of resource variability and intermittency are amplified, highlighting the importance of optimising the VRE plant mix and ensuring the transmission capacity is effectively utilised. Depending on their location, patterns of rival wind and solar generation projects may complement or conflict. This may contribute to efficiency and continuity, competition and congestion, or conversely, underutilisation and overcapacity. These latter outcomes can be expected to be counterproductive for both generators, system operators, and consumers whom all benefit from the efficient dispatch and transport renewable energy when it is available.

With abundant wind and solar resources across the State, Queensland provides a unique case study for REZ development. The long, stringy transmission network has been historically developed around major loads on the one hand, and coal generation sites on the other, with only small pockets of load outside the south-east corner and central Queensland. The State remains one of highest carbon emission intensive regions in the NEM, however the recent announcements of 70% energy sourced from renewable sources by 2032 has set a high bar for the industry. This rapid transition will require careful planning and coordination to deliver the capacity necessary to provide this volume of energy. As has already been seen in recent years (both locally and abroad), that congestion and associated curtailment of VRE generation has prevented full access to this low-cost energy for consumers (Newbery, 2022;

Simshauser et al., 2022). With the best wind and solar resources often being located great distances from major demand centres, this requires careful consideration in REZ design and investment screening.

This research contributes to the literature by considering two important aspects of the VRE industry in Queensland, Australia. First, quantifying the macroeconomic effects that have driven increases to the entry cost of VRE into the Australian market provides a contemporary update to previous literature. Building on this, location and market value analysis calculate the unit cost of energy, and market utility of the nine proposed REZ developments across the region. These insights assist in understanding the specific contribution of REZ to the State's energy supply, which will assist development and investment in transmission and generation capacity over the next decade.

This article is structured as follows; Section 2 provides a review of relevant literature. Section 3 outlines the data sources utilised in the analysis and Section 4 discusses the modelling results and provides real world context. Concluding remarks follow.

2. Literature Review

2.1 Locational value

Australia has some of the world's best combinations of wind and solar resources, with large amounts of available land, covering a broad geographical expanse. The Queensland region faces unique challenges in managing the technical operation of a stringy network with pockets of concentrated load. The existing shared transmission network has historically been designed around the location of large industry and coal infrastructure, not the location of wind and solar resource. The location of best VRE resources in Australia are generally found a long distance from load centres and with limited existing network capacity (Rai & Nelson, 2021). Entrants in these areas have experienced a series of technical issues, including system strength shortfalls[1], spilled energy through curtailment (due to congestion and other technical limitations), degradation of marginal loss factors, and therefore underutilisation (Nelson, 2020; Rai & Nelson, 2020; Simshauser & Gilmore, 2022).

A range of market mechanisms exist to optimise location of generation relative to load and existing transmission infrastructure. Locational Marginal Pricing[2] or Nodal Pricing is a framework that offers individualised pricing at each connection point that incorporates congestion, losses and overall utility of energy. In the NEM there are three important parameters that collectively guide investment decision making with respect to location, viz. regional spot prices, loss factors (and their likely variability) and the risk of output curtailment, which is borne by the VRE participants, not by consumers[3]. Collectively, these variables send very strong signals to generators and project financiers in the due diligence phases of VRE projects. The Marginal Loss Factor (MLF) is a particularly important variable. This loss coefficient is an adjustment applied to all generators, approximating the variance between the measured energy produced at the plant's connection point, and the measured energy subsequently consumed by end users. This coefficient is a static factor, revised annually, and considers thousands of load flow scenarios, which can add complexity and uncertainty for certain participants in more remote locations. While other forms of loss calculation can provide more dynamic feedback to incentivise careful locational investment, the sale and departure of large investors from the Australian market (citing MLF deterioration and uncertainty as a core reason) would indicate that the market signals are sufficient (Nelson, 2020; Simshauser & Gilmore, 2022). Hard lessons learnt by some very remote investments has led to more emphasis being placed on the industry (and project financiers in particular) to understanding the locational risk for their new developments.

[1] System Strength is a term used to define the ability of the power system to maintain voltage phase angle and waveform. Its management has been the subject of several changes to the Australian National Electricity Rules since 2017. These outcomes particularly affect inverter-based generators and is a contributing factor to the complexity of connecting new generators.
[2] A method of non-uniform pricing where each generator is paid an individual price for their energy, based on the real time losses and network congestion at their transmission nodes. This approach provides highly granular feedback to the generator on the locational value that the market places on its energy and its ability to serve load.
[3] For example, in Great Britain and Germany, the output of VRE is 'deemed' and consumers pay regardless of output.

2.2 Market value

Beyond the resource intensity and proximity to load that defines VRE locational value, the market value represents an economic outcome that a project can achieve. To date, VRE generation has seen significant uptake in the NEM (more that 16GW and $24B investment), based on individual project financing, underpinned by long term run of plant power purchase agreements (PPA) with a BBB rated counterparty (Gohdes et al., 2022; Simshauser & Gilmore, 2020). With PPA contracts in place and near zero short run marginal costs, VRE generation has been able to operate with little market exposure and achieve profitability through their sheer volume of output (Rai & Nelson, 2020). In the latter stages of this investment supercycle, increasing comfort with some market risk has emerged, with new projects securing favourable financing agreements with 20-30% merchant exposure (Rai & Nelson, 2021; Simshauser & Gilmore, 2020).

However, this new capacity is of little use to the market if it is not available when needed (i.e. during high demand events), or worse if it contributes to congestion (Joskow, 2011). Market value has been defined in the literature as the revenue generators can derive from the underlying electricity spot market prices (Hirth, 2013; Joskow, 2011). Inherent properties of VRE, such as variability, uncertainty and location[4] are known to affect this value and its ability to be easily integrated into an energy system (Hirth, 2013; Hirth et al., 2015). These factors effectively act as a cost, reducing the market value of the energy being generated. Hirth (2013) categorised these costs as profile costs, balancing costs and grid-related costs. In the NEM, these cost categories manifest through low spot prices during periods of high supply (profile costs), frequency control ancillary services (balancing costs) and marginal loss factors and transmission constraints (grid-related costs).

The utility of VRE has been examined for decades, with Haslett & Diesendorf (1981) considering the capacity credit that could be derived through increasing penetrations of wind power. Many have concluded that at low market shares, capacity value is roughly equal to average output over a period, but degrades at higher market shares (Amelin, 2009; Haslett & Diesendorf, 1981; Peter & Wagner, 2021). Through increased spatial diversity and with sufficient interconnection, VRE generators can increase capacity value, and even more so where their output correlates with load (Keane et al., 2011; LaRiviere & Lyu, 2022; Milligan & Porter, 2006; Peter & Wagner, 2021). The correlation effect, where the generation profile is positively correlated with demand, enables a generator to extract greater revenues from the market (Hirth, 2013).

Joskow & Tirole (2000) highlight the influence that generator siting has on congesting transmission networks and inhibiting efficient dispatch and energy prices. At certain times and following certain investment decisions by generators, the impact of uncoordinated entry via the open access connection framework can be observed in the NEM. This framework has allowed poorly sited generators to restrict energy flows (particularly on interconnectors) and contributed to very localised (but highly impactful) transmission constraints (Bell et al., 2017; Rai & Nelson, 2020; Simshauser, 2021). Though congestion is natural, and at some level efficient, coordinated augmentation and subsequent development of the transmission network can reduce VRE curtailment and provide socially efficient outcomes (Bell et al., 2017; Du & Rubin, 2018; LaRiviere & Lyu, 2022; Wagner, 2019).

2.3 Transmission investment and policy barriers

The existing NEM framework for consumer-funded transmission investment (i.e. the regulatory investment test for transmission) must address an identified need for augmentation, upgrade or new construction, backed by a favourable cost-benefit analysis (Simshauser et al., 2022). Whether this framework is fit for purpose under a market transformation scenario is an open question. Currently, an identified need can relate to an impending shortfall affecting the technical specifications of the electricity rules or demand growth, however, does not apply to anticipatory investment (Bell et al., 2017). This

[4] Although location (and the associated electrical losses) affects all generators, the geographic location of VRE generators can influence the intensity and timing of its energy production.

framework is incomplete in the current context where externalities are not quantified, particularly the price of carbon emissions.

In the not-too-distant past, over-investment in the low voltage distribution network to address reliability constraints and softening of consumer energy demands saw a dramatic rise in network charges to consumers (Rai & Nelson, 2020; Simshauser & Akimov, 2019). Valid consumer concerns of network gold plating and high electricity prices remain relevant with the discussion of 10,000km of new transmission investment being necessary to facilitate the clean energy transition (Australian Energy Market Operator, 2022). The narrow definitions used in the regulatory investment test and limited external benefits that are considered, means that the industry's demands for transmission will outstrip the current framework's ability to facilitate it (Simshauser et al., 2022).

To avoid rapid increases to the regulated asset base, soaring network charges, and delays in delivering transmission upgrades, some network businesses are focusing on generator-funded outcomes in the form of Renewable Energy Zones. These zones would focus on areas of good VRE resource, and coordinate investment to provide economies of scale in transmission infrastructure, increasing the hosting capacity and reliability that would otherwise be unachievable through disorderly independent connections (Simshauser et al., 2022). While REZ developments remain in their infancy in the NEM, the Electric Reliability Council of Texas (ERCOT) achieved positive outcomes from their strategic transmission investment to facilitate vast VRE investment in their competitive REZ developments (Tsai, 2018). With two almost distinct networks and limited transfer capacity between the two, the competitive REZ development was able to increase capacity and load flows between the eastern and western regions of Texas. With the new transmission capacity, wind intense regions in the west were able to reach load centres in the east, providing economic benefits to consumers and easing congestion and spill for wind generators from 17% to 1.2% (Du & Rubin, 2018).

2.4 VRE investment lifecycle

Life cycle costs largely align across VRE technologies, with some subtlety defining wind and solar generation. Through the project initiation phase, extensive environmental and planning assessments, along with wind and solar irradiance monitoring, require not-insignificant financial investment over multiple years just to determine the viability of a new project. Costs accrue quickly as the project passes this stage gate to the detailed project planning phase. At this stage of development, planning, and engineering fees are required to bring the project to fruition and enable the financial investment decision (FID) to be made (Hu et al., 2018). In parallel, numerous contracts are being negotiated, including land access agreements, grid connection and generator performance standards (with the network and market operator), primary and balance of plant procurement (historically via engineering design, procurement, construction (EPC) contracts), operations and maintenance agreements, PPAs and financing agreements (Kucukali, 2016; Underhill, 2010). Given the project's structure as a Special Purpose Vehicle (SPV) using project financing, this suite of bespoke contracts occupies significant time and resources to establish (Esty, 2004).

Once construction commences, the project outgoings reach their peak. Project milestone payments, project management fees, construction contingencies and interest costs continue to be capitalised, up until the point that the project starts generating energy and revenue (Simshauser et al., 2010). Many of the headline issues associated with VRE projects are met through this period. Complexity in generator and system modelling have accounted for considerable connection delays, amassing significant costs in contractor disruptions and liquidated damages (ARENA, 2021; Nelson, 2020; Srianandarajah et al., 2022). Operating expenses can vary greatly from project to project, being affected by location, proximity to other similar projects or industry hubs, and technology specification. Operations and maintenance contracts typically come with availability or performance targets, incentivising operational alignment between functional performance and market conditions (Underhill, 2010). Ongoing fees include operations, maintenance and asset management, connection and network fees, market ancillary services, land access, environmental management, insurance, and financing (Shen et al., 2020).

The timeline between project initiation and its first revenue being generated can vary greatly, but at best will span several years (Kucukali, 2016). To sustain development costs through this time, funds are typically invested into a SPV by a parent company where the development expenses are managed (Esty, 2004). Following the FID and securing project financing from a syndicate of banks, further equity contributions occur and access to project debt enables greater project cashflows. This debt typically operates under in an interest only repayment structure until the debt crystalises at the completion of construction and at the commencement of energy generation. At this stage, repayments typically convert to principal and interest, and the debt is amortised across the project's operating life.

3. Data

As costs for wind and solar projects have come down in the last decade to 2020, these forms of generation have become competitive against other technology types. It now appears that costs have bottomed out, with cost increases being observed in more recent years. Demand for PV panels, inverters, wind turbines, batteries and other emerging technologies has seen rapid increases as part of the global trend of VRE investment. Compounding this increase in demand, changing procurement and risk allocations in construction and uncertainty about connection timeframes have all contributed to inflating project costs. A range of domestic sources have been relied upon to understand the current market of capital and operating costs for new VRE developments in the NEM, including industry reports, academic literature and through industry insights.

Data sourced from Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) for 2022 has proved valuable in assessing the nine proposed REZ developments across Queensland. Datasets have been collated for 10 reference years (2011-2021) and provides demand and capacity output at half-hourly intervals. For each of these reference years, a 30-year time series has been provided. This timeseries represent the actual climatic conditions observed in the reference year and incorporate variability across their planning horizon to allow for probabilistic modelling. Within these data sets, wind and solar PV (single-axis tracking) sites have been selected along with operational demand[5] data for the corresponding period. Comparison between modelled data and actual NEM data (where available) was conducted. Minor scaling was necessary on the time-series data for two wind REZ where slightly elevated output data was reduced to align with observed performance in the NEM.

Marginal loss factors have been determined as an average of the available data (maximum 10 years) for representative locations for the REZ developments. Selection of these locations has been guided by AEMO's ISP recommendations based on either generation sites or transmission nodes.

4. Analysis and Discussion

4.1 Macroeconomic effects on VRE Entry cost shocks

Over the past decade, VRE entry costs have seen steady decreases as the technologies benefits from industry learning, increasing competition, and formalising global supply chains (Graham et al., 2021). The headline categories that contribute to a VRE project's FID are capital and operating costs, cost of capital, the anticipated capacity factor and associated energy revenues. Through this time, favourable economic conditions and government incentives have seen the industry flourish. With falling costs, low costs of capital and increasing market demand for renewable energy, gold rush conditions have seen projects pass their FID with little resistance (Simshauser & Gilmore, 2022). Now, as the world emerges from the constraints of the global Covid-19 pandemic, macroeconomic drivers are presenting challenges to new projects as these core project variables face compounding cost shocks (International Energy Agency, 2021).

Not since the global financial crisis have such sharp increases in capital markets occurred. At that time Simshauser et al., (2010) observed 28-41% increases to the entry cost of open and combined cycle gas turbines into the NEM off the back of simultaneous rises in plant capital costs and the cost of capital. As

[5] Operational demand is the energy required to be delivered to consumers through the transmission and distribution networks. i.e. excluding demand that is satisfied by distributed energy resources such as domestic solar PV. As REZ are dispatched at a market level, satisfying operational demand is relevant for their analysis.

the world returns to business as usual following the pandemic and energy prices soar as a result from shifting supply chains of natural gas, many major global economies are grappling with high levels of inflation. In efforts to mitigate this, central banks have implemented regular increases to the cash rate over 2022 and into 2023. Although driven by different underlying factors, the conditions are set for a similar entry cost shock on VRE projects in the NEM.

A report issued by the International Energy Agency (2021) flagged significant commodity price increases in polysilicon (400%), steel (50%), copper (60%) and aluminium (80%) over a 12-month period that would affect VRE supply chains. These commodity prices have flowed onto increases in the VRE plant capital costs, with some equipment manufacturers reporting price increases of ~40% to combat increases in their supply chain (Standard and Poor, 2022). By their nature, VRE generators do not have ongoing fuel costs to produce energy, so they are highly sensitive to fluctuations in their capital and operating costs in determining their long-run marginal costs. As such, these are core components of their FID.

Compared to the existing fleet of baseload black coal generators (who have historically been dominated by balance sheet financings) most VRE projects in recent years have been funded on an individual project financing basis. This approach has been demonstrated to deliver a lower unit cost of energy for VRE projects, reducing their barriers to entry into the market (Simshauser & Gilmore, 2020). In these cases, debt shares ranging from mid-50s and to as high as 80% of the capital structure makes that the project financing costs a key project risk (Gohdes et al., 2022; Steffen & Waidelich, 2022). As the global economy grapples with rising inflation, the cost of capital has taken a sharp rise in response. As Figure 1 highlights, the market conditions over the last decade have been typified by stable inflation and a falling cost of capital. Combining this with falling capital plant costs, the conditions have been primed for these types of capital-intensive investments. However, the dramatic surge in both inflation and the cost of capital in 2022 exposes the industry to tighter expenditure and lending constraints than it has experienced since maturing. From May-December 2022, 9 consecutive monthly increases were made to the cash rate by the Reserve Bank of Australia. This is also reflected in the Bank Bill Swap Rate (BBSW), which is an important benchmark for variable interest rates in Australian corporate financing. While costs would have mostly been committed for the projects delivered in 2022, the 5GW of committed VRE capacity in the NEM will be exposed to the full extent of these distinct entry cost shocks.

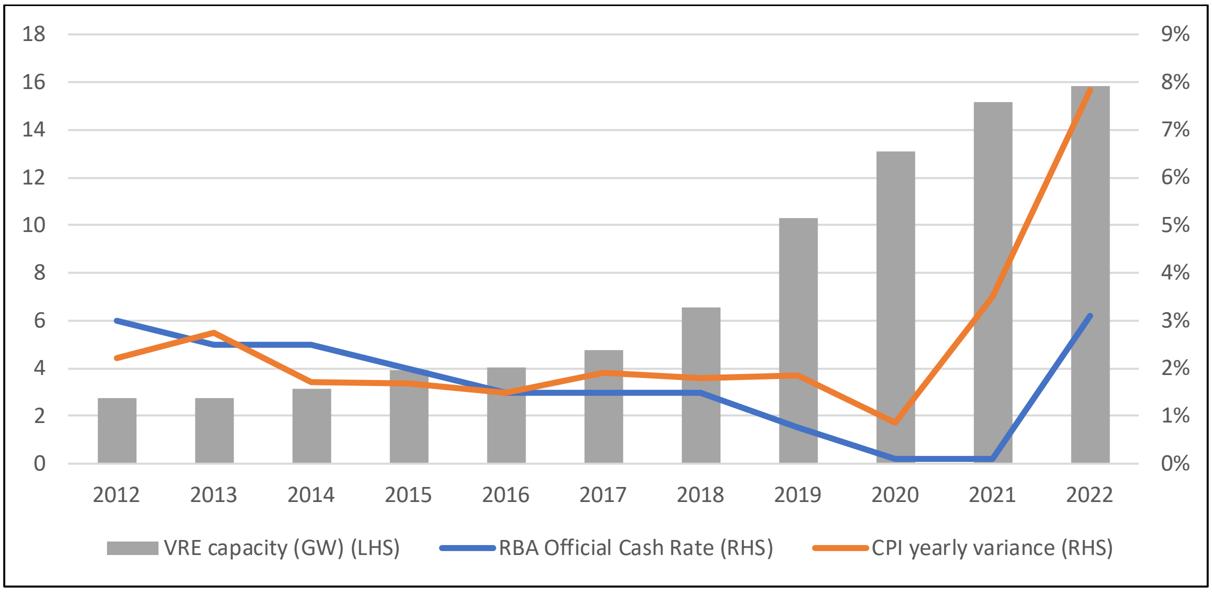

Figure 1 - NEM VRE installation and macroeconomic fluctuations

4.2 VRE Entry costs in 2022

As the entirety of these macroeconomic effects will continue to become apparent as new projects are committed, a contemporary analysis of VRE project cost inputs and their effect on the unit cost of energy. Simshauser et al. (2022) recently established benchmark entry costs for Queensland (real 2020), where a 250MW wind project could deliver a unit cost of energy of $51.20/MWh and a 200MW solar project providing $47.30/MWh. Beyond the macroeconomic drivers, industry insights suggest that there have also been recent sharp increases in project delivery expenses since this time. With lessons learned from inappropriate risk allocation in past projects and the greater understanding of the grid connection processes and scheduling, there has been a reluctance for projects to be delivered on a turnkey basis where the construction contractor manages all the delivery risk. This is particularly relevant for solar projects, where procurement of long lead time items (such as PV panels and inverters) are increasingly being managed by the project owner.

The process for valuing energy has evolved from comparing technologies by their Levelised Cost of Energy (LCoE), to the use of complex project finance (PF) models to assess project viability. Capturing highly granular life cycle costs, including development, engineering, construction, operations, and financing, PF modelling overcomes some of the criticisms that exist for LCoE as the approach is technology agnostic. This process enables the calculation of a base energy price that considers the real-world constraints of debt sizing and serviceability, to deliver the required post-tax equity rate of returns that underpin the investment. Further, the ability to closely test the sensitivity of individual variables enables investors and financiers to carefully understand where risks exist for their projects.

To reassess the current entry costs against the 2020 benchmark, the key variables that contribute to the underlying unit cost of energy have been defined in Table 1. Plant capacity of 250MW (AC) is representative of the scale of projects currently being delivered across the country. While some costs can be expected to reduce as scale increase, for basis of this analysis (and comparison to the 2020 benchmark costs), this size is considered appropriate. Using the resources described in section 3, capital and operating costs have seen a marked increase. In reviewing these resources, it has been observed that some have only captured direct operations and maintenance costs, failing to fully appreciate the whole scope of operations costs. Some of these additional costs (which have seen increases in their own right) include insurances, owner's asset management expenses, network and connection fees, market ancillary services and ongoing maintenance capital expenditure. By re-calibrating these variables to properly reflect the current market conditions, we see the gap narrows for capital and operating costs between the two technology types.

The current BBSW has been used with a 200bps operating debt margin to reflect the financing costs offered to these types of projects, consistent with Gohdes et al., (2022) recent analysis. For simplicity, this has been applied as a single financing tranche amortising over 25 years, as a principal and interest repayment occurring once annually. While uncertainty exists over the future interest rate trends, higher rates in early years is expected to have a greater impact on the projects net present value and will highlight the upper bounds of interest rate impacts.

On face value, the assumed indexation may be considered low in light of the recent increases. However, over the assumed 30-year operations of these facilities, it is deemed appropriate to revert to the mid-point of the 2-3% inflation target of the Reserve Bank of Australia. A project life of this duration is consistent with current technical design certifications being provided and satisfies the expectations of financiers who take confidence that the project will remain viable for at least five years beyond the repayment of debt. To align with the assumptions used in the 2020 benchmark entry costs, a post-tax equity hurdle rate of 8% has been used. Noting that the risk-free rate used in the capital asset pricing model has increased since 2020, it could be argued that a corresponding increase to the required rate of return should occur. However, to enable direct comparison with previous works, this assumption has remained unchanged. Finally, it is important that constraints be applied to financing to ensure debt obligations remain satisfied. Accordingly, a minimum debt service cover ratio of 1.25x is required.

Table 1 - VRE Project specification (A$)

Project Specification	Wind	Solar
Capacity	250MW	250MW
Annual Capacity Factor	35%	28%
Marginal Loss Factor	0.97	0.96
CAPEX	$2,180/kW	$1,807/kW
OPEX p.a.	$48/kW	$38/kW
Operating years	30 years	
Hurdle Rate (Equity)	8%	
Debt Tenor	25	
Interest rate	5.29%	
Indexation	2.50%	
Corporate Tax Rate	30%	

The PF model (whose iterative notation is described in Appendix 1) has been designed to allow the optimisation of numerous variables and analyse variable sensitivities to understand their impact on project risk. To calculate the underlying unit cost of energy ($/MWh), the following PF model objectives are defined:

- Objective 1: minimise long run marginal cost,
- Objective 2: net present value equal to the investment hurdle rate,
- Objective 3: optimise debt level, such that gearing does not exceed 80%, and
- Objective 4: debt service cover ratio to exceed 1.25x across the investment life.

In satisfying these objectives, the minimum bounds of a new VRE investment can be defined.

To start the analysis, the PF model has been calibrated using the cost inputs from Simshauser et al. (2022) to replicate their 2020 entry costs of $51.20 (Wind) and $47.30 (Solar PV). This will allow the contribution of individual the cost variables to be quantified in the present-day market. These results are broken down in Table 2.

The first cost shock that is introduced to the model considers increase only to the capital and operating costs of the project. Adjusting these two variables alone saw increases of $5.07/MWh (Wind) and $12.05/MWh (Solar PV). These disproportionately affect solar generation, which is primarily due to the lower annual capacity factor (ACF) and the higher electrical losses that typically affect this technology.

Next, current borrowing conditions saw further increases of $6.70/MWh (Wind) and $8.57/MWh (Solar PV). This highlights the compounding effects that financing costs have on the unit cost of energy, where capital costs are subject to higher interest rates over the project's life. Further to this point, objective 3 of the PF model optimises the gearing level of the project, which saw reductions in the optimal level of gearing from ~78% to 72%, highlighting the sensitivity that financing has on delivering investment outcomes. These financing changes will not only affect new projects. As the pipeline of project financed VRE projects reach the end of its initial tenor and undergo refinancing, the current market rates for debt will apply. This may test the liquidity of projects that were committed under competitive conditions for PPA's who are now subjected to the upper bounds of debt assumptions at financial close.

Table 2 - Benchmark VRE project entry costs (A$)

Technology type	2020 Entry Costs	2022 Plant capital costs increase	2022 Financing cost increase	2022 Entry cost
Onshore Wind	$51.20	+$5.07	+$6.70	$62.97
Solar PV	$47.30	+$12.05	+$8.57	$67.93

It is clear from this data that the rapid changes in market conditions have produced entry cost shocks of similar magnitude to those observed following the global financial crisis (28-41% in 2010 compared to 23-44% in 2022). Given the volume of new investments necessary to achieve the recently announced State targets, these cost shocks may present investment challenges in delivering new capacity at the required rate.

4.3 Locational value Queensland REZ developments

Having benchmarked the current entry costs on new VRE projects, we can build upon this to conduct a specific analysis of the locational value of REZ developments across Queensland. The key variables used to define locational value of individual VRE projects within a REZ site are the available wind or solar resources, and their ability to efficiently deliver their energy to the point of consumption.

The intensity of the wind and solar resource across the proposed REZ sites was assessed using the capacity output time series data sets (as described in section 3) to produce a half-hourly generation profile and long term expected annual capacity factors (ACF) for each location. To assess the electrical losses between the REZ and consumption, representative sites for each zone were selected and a retrospective assessment of 10 years of marginal loss factor trends (where available) was used to consider existing load flow dynamics. As broad MLF trends over the last decade have seen a decline upon the introduction of VRE, most have strengthened in the most recent years. While future volatility will inevitably occur as load flow dynamics change, we consider that an averaging of the available data accounts for short term fluctuations. The model inputs for both ACF and MLF are shown in Table 3. Again, the static inputs in Table 1 that are utilised in the PF model have been applied across the REZ projects. Although cost variability will inevitably exist between specific VRE projects, insufficient data exists for location specific cost trends to be determined within the State.

Consistent with the PF model objectives in section 4.2, we are able to determine the minimum unit cost of energy that can be delivered from each REZ. Ordered from the lowest cost to highest we are able to identify the locations with the greatest locational value (i.e. low unit cost of energy). While proximity to the load can provide some improvements, the overall resource intensity often provides the largest driver for determining project feasibility. Consistent with the trend across the NEM, solar MLF's are consistently weaker across the reference sites compared to wind. Further, wind loss factors have less impact than solar across all REZ developments except for those located very close to load centres. In spite of this, we see greater consistency in the base price across solar projects with a variance of $11.94/MWh, compared to $22.87/MWh for wind projects.

The unit cost of energy calculated in Table 3 essentially defines the minimum energy price required to underpin a project. As Gohdes et al. (2022) points out, projects can achieve a higher level of gearing and reduced cost of capital when they secure a power purchase agreement for the early life of the project. Their research identified this as being the most meaningful process a VRE project could undertake to reduce project risk. In calculating the unit cost of energy for each of these REZ locations, this figure is then reflective of the minimum PPA strike price necessary to underwrite the project. Considering the recent trends in PPA pricing in the Australian market it would be challenging for many of these projects to progress. With bundled contracts in the order of $60-65/MWh in recent years (Srianandarajah et al., 2022), a very small number of the considered projects would be able to proceed. For continued VRE investment, it will be necessary for PPA prices to reflect market conditions and the underlying changes to project costs.

These calculations provide useful insights for network and investment planning within the region. REZ who have high locational value for both technologies, should be prioritised for transmission investment as the corresponding investment in generation would be competitive for the new hosting capacity. Considering their comparative advantage, the Darling Downs and NQ Clean Energy Hub stand out with high locational value for both their wind and solar resources.

Table 3 - REZ VRE unit cost summary

Location	$/MWh (A$)	ACF	MLF
Wind			
NQ CEH	$59.36	0.34	1.06
Far North	$63.43	0.35	0.96
Darling Downs	$65.05	0.34	0.98
Isaac	$65.89	0.31	1.06
Fitzroy	$69.61	0.32	0.96
Barcaldine	$74.18	0.30	0.96
Northern Qld	$74.56	0.30	0.96
Wide Bay	$78.39	0.30	0.92
Banana	$82.23	0.27	0.96
Wind REZ Average	*$70.30*	*0.31*	*0.98*
Solar			
Barcaldine	$64.37	0.32	0.90
Darling Downs	$67.05	0.28	0.98
Fitzroy	$67.55	0.28	0.96
NQ CEH	$68.13	0.30	0.90
Banana	$69.57	0.29	0.90
Northern Qld	$72.88	0.28	0.90
Isaac	$73.01	0.29	0.88
Far North	$75.34	0.27	0.90
Wide Bay	$76.32	0.27	0.90
Solar REZ Average	*$70.47*	*0.29*	*0.91*

4.4 Market Value

4.4.1 Correlation effect

While locational value is important for determining individual project viability, in a high capacity VRE network the market value of the generation is important at a system level (Hirth, 2013; Ueckerdt et al., 2013). In general, Queensland benefits from a complementary pattern of wind and solar generation, with wind output highest through the night and dipping as solar peaks through the day. Figure 2 highlights this relationship. Although locational variability exists, the output profile is quite tightly clustered based on technology type. Hirth (2013), outlined key characteristics that affect the market value of VRE generation across varying timescales and market shares. The “costs” that reduce VRE market revenue relate to its generation profile, the balancing services required to overcome forecast uncertainty, and the grid-related constraints and congestion that reduce its output. Profile costs have the greatest proportional effect in reducing market value of VRE according to their research. Without the provision of long duration energy storage, the value of VRE is determined by the level of demand at the time it is produced. As such, the correlation effect suggests that if a VRE generator whose profile is positively correlated with demand will derive more revenues from the market than a constant source of energy. While VRE generation may exhibit high market value at low levels of market share, REZ developments are designed around full, or very high percentage of installed VRE capacity. To be effective, REZ will rely on careful planning to ensure that installed capacity is appropriate for demand conditions.

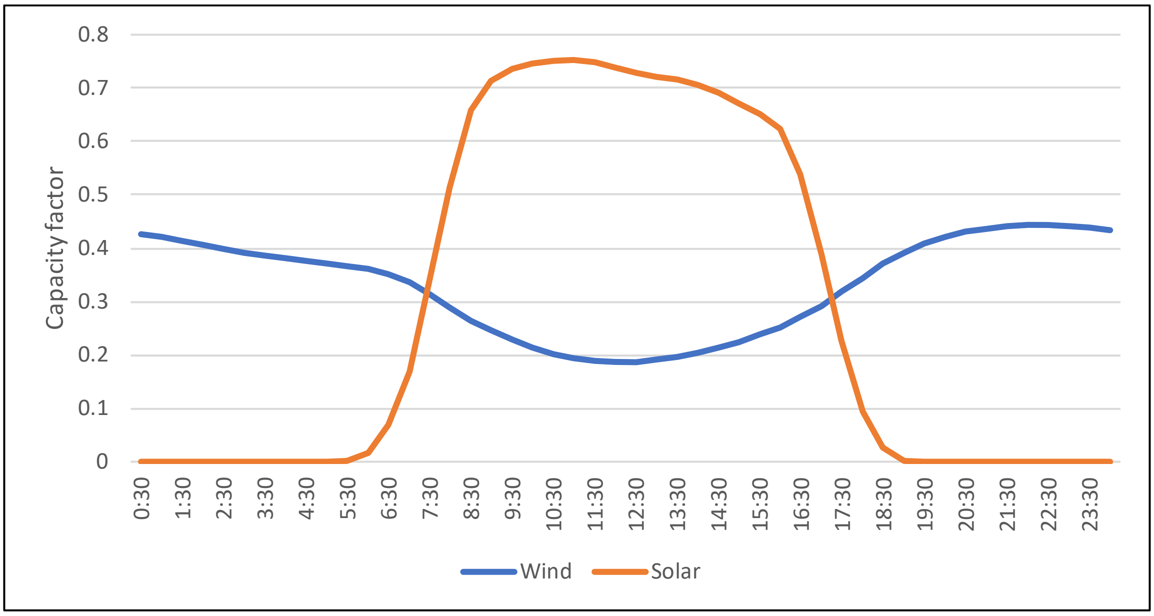

Figure 2 - Average Queensland generation profile

To understand the correlation effect across Queensland REZ, high resolution timeseries data was used to calculate the correlations between wind and solar generation and state-wide operational demand. Correlation of the independent variables is calculated in the following scenarios using equations 1.1-1.3;

(1.1) $\rho_{S_{REZ},D}$ (1.2) $\rho_{W_{REZ},D}$ (1.3) $\rho_{S_{REZ},W_{REZ}}$

where:

- S_{REZ} – half hour solar output at individual REZ
- W_{REZ} – half hour wind output at individual REZ
- D – half hour system level operating energy demand

Presented in Figure 3, wind demonstrated a slight positive correlation with operational demand across all REZ sites. In this situation, positive market outcomes can be derived from wind VRE connections. As previously highlighted, this will translate to high market value as greater revenues are typically achieved during periods of high demand. As market share continues to rise, technology specific oversupply can occur and greater competition to dispatch will soften the effect on spot prices (Cutler et al., 2011; Simshauser, 2020).

In contrast, the solar correlations varied from slight to moderately negative with the current level of operational demand. While some seasonal variation may exist (i.e. where solar generation aligns with high summer daytime temperatures and cooling demands), the overall correlation with demand indicates that it does not provide significant value to the market. It should be noted that Queensland already has high levels of distributed PV (which reduces operational demand) so this correlation to overall electricity demand is unlikely to fully represent its utility. As observed in other recent works, the underlying demand for electricity remains high during the solar noon, and the existing market share of solar PV (through distributed and large-scale installations) is distorting the correlation with operational demand in this analysis (Simshauser, 2022).

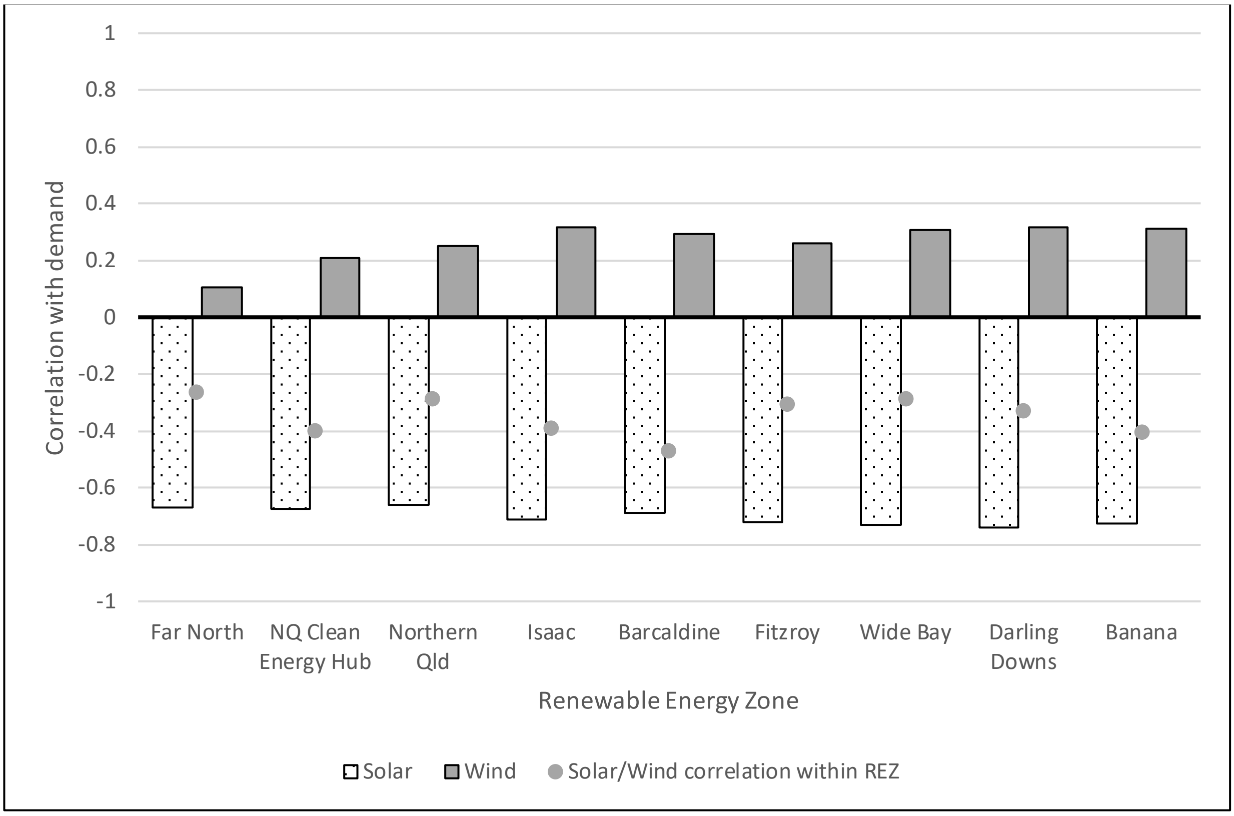

Figure 3 - REZ generation output correlation with demand

Within a REZ, the correlation between technology types showed slight to moderate negative correlation. In contrast to correlations with demand and in the context of a REZ, a negative correlation between technology types is advantageous. This enables the selection of appropriate volumes of complementary generating capacity to connect. While this minimises some immediate competition between technologies, the "peaky" nature of solar generation (the concentration of all its generation within a few hours) means that optimising capacity of wind and solar within a REZ becomes quite complicated. Simshauser et al. (2022) investigated this issue, finding optimal subscription of a Queensland REZ (in minimising combined unit costs and transmission infrastructure) would require a wind to solar ratio of 83:17, with generating capacity being oversubscribed to transmission capacity by 37%. Applying this ratio to average REZ output, a relatively stable intra-hour generation profile can be achieved (see Figure 4).

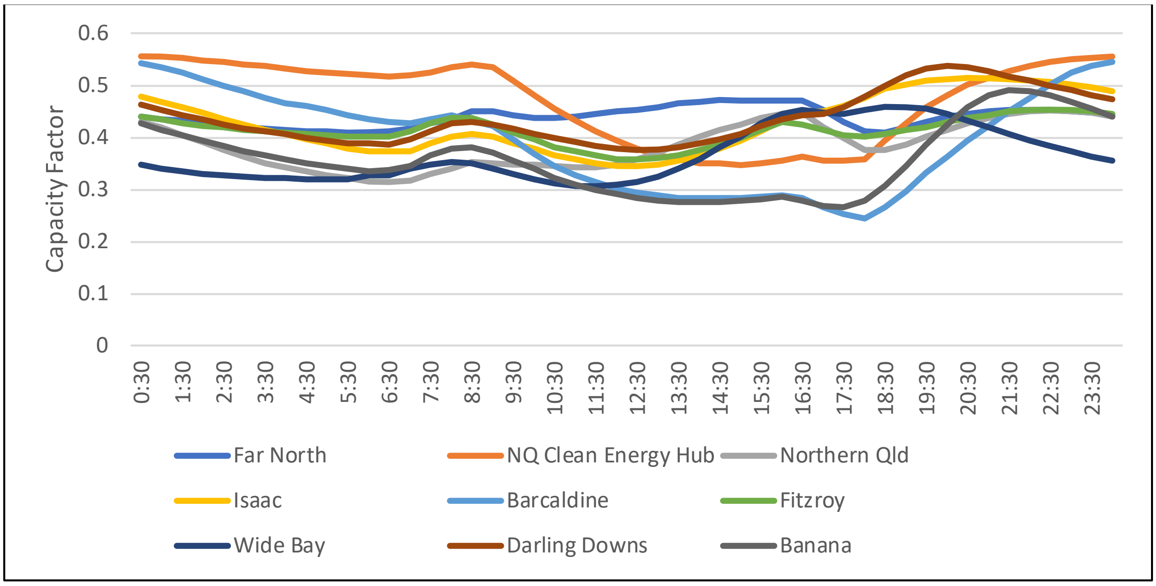

Figure 4 - REZ intra-hour generation profile

4.4.2 Baseload generation capacity

Looking beyond the correlation effect, how REZ generation profiles compare to the generation profiles of incumbent participants is worth considering. Across 2011-2021 period, generation profiles for the existing fleet of baseload generators provides useful insights. With 8 coal generators in service across Queensland, consisting of 22 individual generating units and over 8000MW of installed capacity, the state remains one of the most emissions intensive in the NEM. Through this period, these generators have supplied the vast majority of energy to consumers, and until recently have been very consistent in their behaviour. By their nature, coal generators have limited flexibility and only make strategic changes to their output over longer timescales. This is shown in the generation profile in Figure 5, where there is limited intra-hour variability for most generators. As capacity factor increases, the ability to correlate with demand is reduced as the generator's remain at a consistent level of output and rides through market volatility and fluctuations in energy demand.

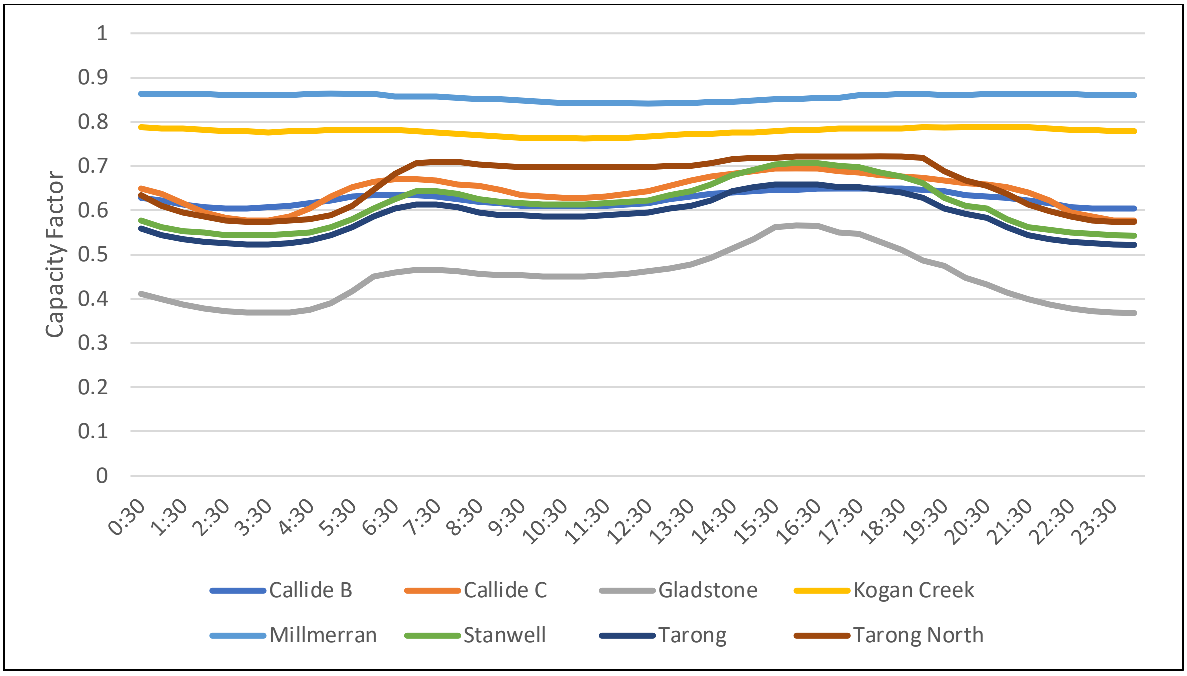

Figure 5 - Baseload intra-hour generation profile 2011-2021

Building on previous analysis, half hour generation for each baseload generator was correlated with demand:

(1.4) $\rho_{B_l,D}$

Where B_l represents the baseload generator (*B*) at location (*l*).

Additionally, we consider the combined wind and solar REZ profiles at each location (*l*), and their correlation to demand.

(1.5) $\rho_{REZ_l,D}$

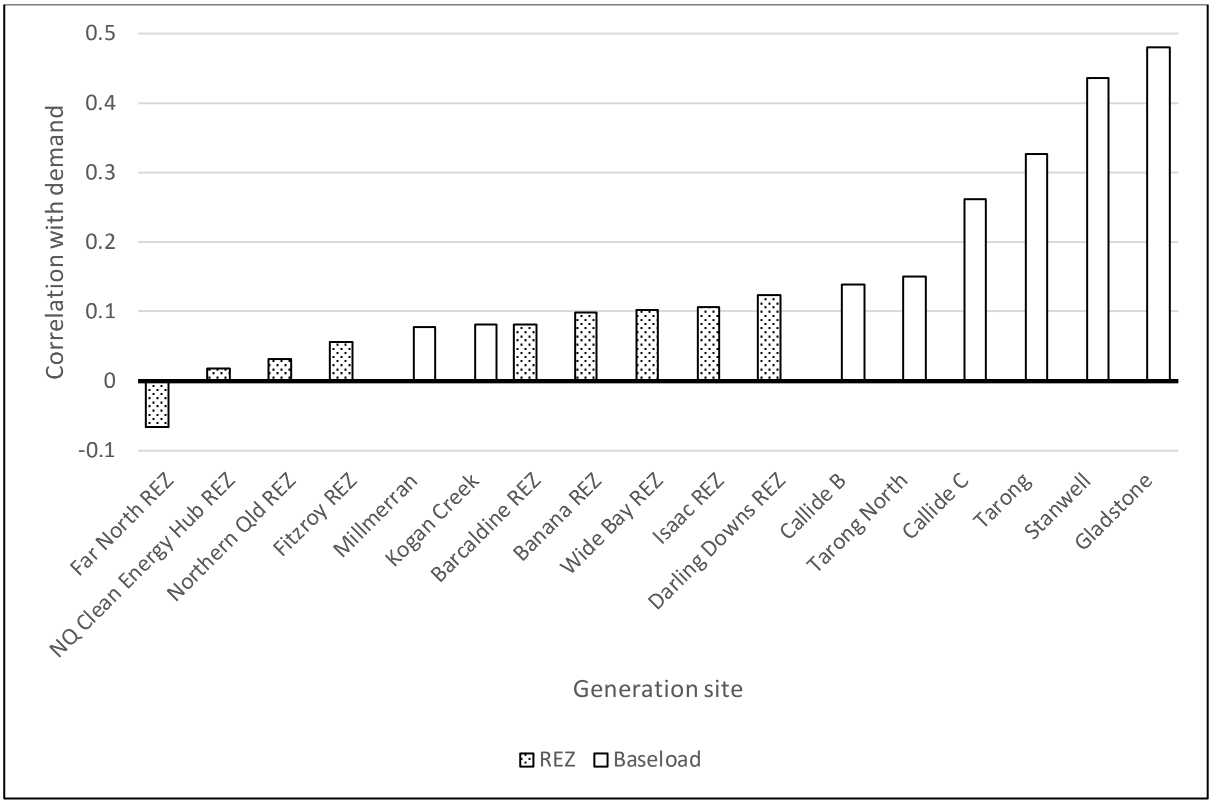

Figure 6 - Generation output correlation with demand

Figure 6 presents data from scenario's 2.4 and 2.5. As we first consider the correlation of existing baseload generators, all demonstrate a positive correlation with demand. While in most cases this relationship was only slight, those with a greater number of individual generating units could adapt their operations to respond to demand fluctuations. However, this aligns with lower levels of utilisation, as shown previously in Figure 5. Across the period Gladstone (6 units) had a utilisation rate of 45%, Stanwell (4 units) 61%, Tarong (4 units) 58%, and Callide C (2 units) 64%. Considering the remaining baseload generators (where utilisation averaged 73%), it is evident that a suitably sized and proportioned REZ can have a similar correlation to demand as a baseload generator. It is important to note the current assumptions exclude any energy storage systems. It is expected that these correlations can be improved through the addition of REZ specific storage capacity. Adding dispatchable capacity to the REZ (a functionality utilised by the baseload generators considered here) will enable management of output to follow demand more closely. In most cases, the proportion of wind to solar appeared appropriate, however some locational refinement may be necessary to improve the correlation with demand (i.e. the Far North REZ).

4.4.3 Market value factor

Although there is only a short history of large scale VRE generation across Queensland, it is important to consider how the modelled scenarios compare to real market operations. Connections in the Far North

(Mt Emerald Wind Farm and Ross River Solar Farm) and the Darling Downs (Coopers Gap Wind Farm and Darling Downs Solar Farm) provides NEM market data that enables analysis to represent REZ dynamics between 2019-2022. We apply the output of these generators in a stylised REZ with 1,000MW transmission hosting capacity, with connected VRE capacity of 1,370MW, proportioned and scaled (83% wind to 17% solar) according to Simshauser et al., (2022). The scenario uses 5-minute NEM market data of the identified REZ generators and the incumbent baseload generators to determine their market value factor. The revenue for the REZ (REZ_R) in each 5-minute dispatch interval is calculated as follows:

(2) $$REZ_R = \left(\sum \left[w_o \cdot w_{sf} \cdot REZ_{MW}\right], \left[s_o \cdot s_{sf} \cdot REZ_{MW}\right] \right) \cdot RRP$$

where:

- w_o , s_o is the output from the wind/solar generators with the REZ,
- w_{sf} , s_{sf} is the scaling of wind to solar capacity sited within the REZ, and
- REZ_{MW} is the total nameplate capacity of the REZ.
- RRP is the 5-minute regional reference price in $/MWh

The volume weighted average price ($\bar{p}_g$) for the REZ is then calculated for each calendar year as follows:

(3) $$\bar{p}_g = REZ_{R_t}/E$$

where:

- REZ_R is the sum of REZ revenues for each dispatch interval *t* across the period, and
- E is the total MWh of energy dispatched across the period.

We then extrapolate on this using equation 3 to determine the annual market value factor for two sample REZ sites and each of the baseload generators. The market value factor (v_g) allows the assessment the specific utility a generator compared a constant source of energy, calculated by:

(4) $$v_g = \bar{p}_g / \bar{p}_s$$

where:

- $\bar{p}_g$ is the volume weighted average price of the generator (g), and
- $\bar{p}_s$ is the system base price, being the time weighted average price of the spot market over a given period.

The results of these calculation are summarised in Figure 7, showing the annual market value factors over the past four years where large scale VRE generators have increased their participation in the market. Noting that there was insufficient data from the Darling Downs REZ in 2019, as much data as possible has been included to gauge REZ value. Through this period, the Queensland region has seen considerable market volatility, with low average spot prices of $41.22/MWh in 2020 contrasted against record highs of $205.14/MWh in 2022. Although the two REZ are found at the lower bounds of the selection of generators the magnitude of difference remains small, particularly against those coal generators with a small number of generating units. Being intermittent in nature and driven entirely by weather, their ability to provide energy when the market values it is better than expected. The ability to produce energy when needed is an important aspect of market operations and these REZ scenario's (populated solely with VRE) demonstrate their utility. Opportunities intuitively exist to improve this market value factor further with the introduction of storage at these locations, improving value and reducing congestion. When compared to existing literature, we have not observed the deterioration of market value even with the considerable price volatility across the period.

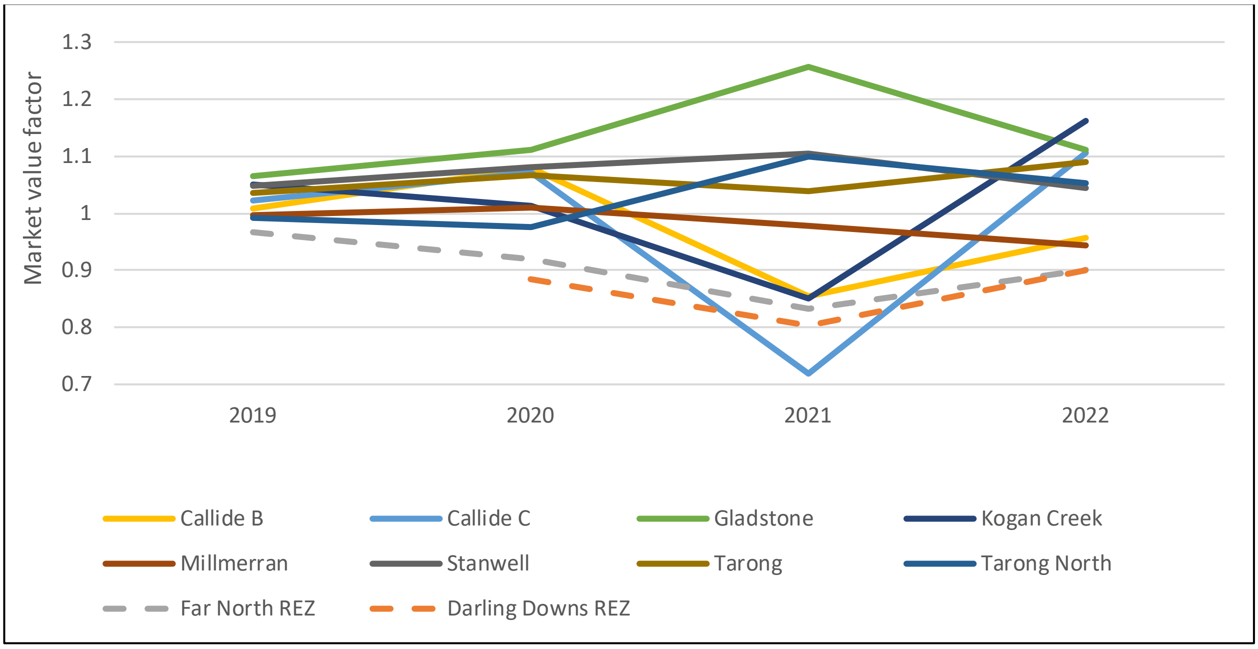

Figure 7 - Market value factor of Queensland generators

Although limitations exist in the analysis (i.e. the effect of REZ scaling on price has not been analysed) it provides a useful starting point for further analysis. Of particular interest is how the design of a REZ can be refined to offset the energy currently sourced from baseload generators ahead of their forecast retirement. As more operational data is produced across the region, these analyses will become more fruitful. Further, the analysis of complimentary storage technologies and their ability to improve REZ market value is a logical next step. In light of recent announcements by the State government on utilisation of coal generators in the future, significant opportunities exist to design, size and implement REZ infrastructure to minimise shocks as baseload generation exits the market.

5. Conclusions

This paper has provided useful insights into the current state of the VRE market in Queensland. The underlying increases to the price of raw commodities during the global post-pandemic recovery is starting to show signs of significant increases in VRE capital plant costs. We have observed significant increases in VRE entry costs, with these effects expected to continue into 2023. The increase in the cost of capital in response to rapidly rising inflation is compounding these effects. The high proportion of debt supporting both new VRE investment and those subject to near term refinancing will face tightened money markets and higher business case scrutiny. This has the potential to present liquidity issues for existing projects that have underperformed through operations. For new projects, offtake agreements will need to escalate in line with these cost shocks to facilitate continued investment in the industry.

New information has been presented that quantifies the locational value of the nine proposed REZ developments across Queensland. With rapid investment in this region expected over the next decade, this assessment can guide investment towards the most valuable VRE resources and the efficient advancement towards the State's decarbonisation targets. With relatively consistent solar resource across the area, proximity to load can assist the underlying business case. Wind resources have greater variability, but provide a complementary generation profile to solar, which will assist in optimising plant mix to maximise the utilisation of transmission investment.

The correlation effect of individual wind and solar resources and their alignment with load was measured. Generally poor correlation was observed but can be improved through optimising VRE plant mix within a REZ. The behaviour of incumbent baseload generators was found to be analogous to the modelled behaviour of a REZ. This provides an opportunity for further research in assessing the contribution of storage in supporting the VRE generation within a REZ to supplement baseload generation.

Limitations in the duration of operational data, and detailed information about REZ capacity limited further analysis in the specific Queensland context. It is anticipated that further analysis will be possible as more detailed information becomes available for these zones in coming years. Further research is justified into the extent of the current entry cost shocks as they continue through 2023-24 and how the introduction of storage will impact the observed VRE behaviour within a REZ.

6. Appendix 1. PF Model summary

The PF model can be used to manage VRE project variables to optimise long run marginal costs and allows analysis of variable sensitivity and risk. The PF model is calculated as follows:

Costs (π_t^C) and revenues (π_t^R) are escalated in each period (year) *t*, at the assumed rate of inflation (CPI):

(1) $\pi_t^C = \left[1 + \left(\frac{CPI}{100}\right)\right]^t$, and $\pi_t^R = \left[1 + \left(\frac{CPI}{100}\right)\right]^t$

Total energy output (Q_t) is presented in megawatt hours and is calculated using the installed capacity *k*, annual capacity factor *ACF*, and the number of hours (*h*) in the period.

(2) $Q_t = k \cdot ACF \cdot h$

Dispatched energy q_t is reduced by losses that occur up to and including the connection point including the forced outage rate (*FOR)*, auxiliary load (*Aux*), and the marginal loss factor (*MLF*) for the given period:

(3) $q_t = Q_t \cdot [1 - \Sigma(FOR + Aux)] \cdot MLF_t$

The PF models seeks to determine the minimum electricity price required to achieve the investment hurdle rate, which is considered to the plant's long run marginal cost. This minimum electricity price (*LRMC)* is calculated for year 1 and escalated in ongoing periods using equation (1). Revenues at time *t* are calculated using the dispatched energy and *LRMC*, escalated to present dollars.

(4) $R_t = (LRMC \cdot \pi_t^R)\, q_t$

Annual operating expenses (*OPEX*$_t$*)* include fixed operations and maintenance costs (FC_t) of the plant are applied on a $/MW rate to the installed capacity (*k*), and variable operating costs (VC_t) which are applied on a $/MWh basis to the volume of dispatched energy. Escalation again occurs using equation (1).

(5) $OPEX_t = (FC_t \cdot k + VC_t \cdot q_t)\, \pi_t^C$

Earnings before interest taxes, depreciation, and amortisation (*EBITDA*) at time *t* is calculated as:

(6) $EBITDA_t = R_t - OPEX_t$

Initial plant capital costs ($CAPEX_0$) are considered to be incurred overnight in Year 0. Where ongoing capital expenditure occurs ($CAPEX_t$), these costs are considered real in the year that they are incurred (i.e. not subject to cost escalation). As capital costs are subject to tax depreciation across their useful life (*L*), the straight line depreciation (D_t) provides a linear markdown towards its residual value (*R*), in the given period is calculated by:

(7) $D_t = \left(\frac{CAPEX_0 - R}{L}\right) + \left(\frac{CAPEX_t - R}{(L - t)}\right)$

The debt financing portion of the PF model calculates the principal (P_t) outstanding and interest (I_t) repayments as the debt amortises across a period less than its effective life. Although the PF model is capable of separating the debt facility into multiple tranches with periodic refinancing, to fully appreciate the current entry cost shocks and future macroeconomic uncertainty, a single tranche with fixed interest rate (*i*) across the term has been applied. For simplicity, repayments are calculated as an annuity (*n*), across the loan term (*T*). The total repayment (RP_t) in each period is:

(8) $RP_t = P_t \frac{\frac{i}{n}\left(1+\frac{i}{n}\right)^{t \cdot n}}{\left(1+\frac{i}{n}\right)^{t \cdot n} - 1}$

Where the interest repayment (I_t) portion is given by:

(9) $I_t = P_t \cdot \frac{i}{n}$

At this point, taxation occurs on earnings less the depreciation and interest. The tax obligation (τ_t) is calculated at the nominal corporate tax rate (τ_c).

(10) $\tau_t = (EBITDA_t - I_t - D_t) \cdot \tau_c$

To ensure adequate cash flow, a debt service over ratio ($DSCR_t$) of >1.25x is required to be maintained to avoid lock-up and potential lender intervention. To monitor this, cash available for debt service ($CAFDS_t$) is found by:

(11) $CAFDS_t = EBITDA_t - CAPEX_t - \tau_t$

Where $DSCR_t$ in a given period is then determined by:

(12) $DSCR_t = \frac{CAFDS_t}{RP_t}$

The investment decision is made based on the net present value of the post-tax return on equity (ROE_t) across the project life. The equity returns in a given period are given by:

(13) $ROE_t = CAFDS_t - RP_t$

Where the equity Net Present Value (NPV_E) of a given hurdle rate (h) across the expected life (L).

(14) $NPV_E = \sum_t^L \frac{ROE_t}{(1+h)^t}$

Finally, the PF model is designed with the following objectives: minimise $LRMC_0$, $NPV_E \geq$ \$0, and $DSCR_t \geq 1.25$, while optimising the debt level with a gearing limit of 80%.

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