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Generator Revenue in the Australian National Electricity Market with High Renewables and a Synchronous Generation Constraint

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Abstract

Growing policy efforts to reduce fossil fuel related greenhouse gas emissions, along with recent rapid declines in the costs of wind and photovoltaic (PV) renewable generation options, are currently driving major renewables deployment in electricity industries around the world. With no fuel costs, wind and PV have very low short run marginal costs (SRMCs), and in competitive wholesale electricity markets are incentivised to bid their variable and somewhat unpredictable generation output at or near the bottom of the merit order, to ensure being dispatched. The resulting lower wholesale market prices at times of high renewable generation has, of course, implications for market revenues for all generation technologies. Insufficient revenues for renewable technologies, in the absence of external policy measures, will be a disincentive to market entry and hence reduce their uptake, and associated emission reductions. Insufficient revenues for conventional dispatchable plant has the potential to drive longer-term resource inadequacy and system security challenges. Furthermore, wind and PV do not provide inherent inertia to assist in maintaining short-term frequency stability, unlike conventional plant with synchronous generators. A number of electricity industries are imposing minimum synchronous generation constraints on dispatch to ensure sufficient system inertia. This out-of-order dispatch of conventional plant also has implications for wholesale pricing and generator revenues.

While high renewables scenarios have been modeled for the Australian National Electricity Market (NEM), most previous studies have focused on the technical feasibility to reliably meet demand with variable renewables, and the overall industry costs. Few studies to date have considered market outcomes such as generator revenues, particularly when considering the implications of transmission constraints and payment for out-of-order dispatch. This study seeks to fill these gaps by exploring impacts on generator revenues from growing wind and PV penetrations in the NEM, including consideration of interconnector constraints and a minimum synchronous generation requirement, using the market modelling tool PLEXOS.

Results of the modelling suggest declining wholesale prices and generator revenues with increasing renewables contributions. Depending on market arrangements for out-of-order dispatch, a synchronous generation constraint increases wholesale prices overall, but causes strong curtailments and revenue loss for wind generation, while increasing coal and gas generation and revenues.

1. Introduction

Serious action to reduce Australia's contribution to dangerous climate change must involve a reduction in emissions from its fossil fuel dominated electricity sector. This in turn will very likely be primarily facilitated by major renewable energy (RE) deployment. Variable renewable generation technologies, more specifically wind and solar photovoltaics (PV), have shown particular promise with rapidly decreasing costs and soaring deployment worldwide. The overall economic and technical implications of integrating these technologies into electricity industries around the world have been explored in some detail, including for the case of the Australian National Electricity Market (NEM) (Reedman, 2012; Elliston et al., 2013; Riesz et al., 2016).

Because of their zero fuel costs and thus low operational costs compared with traditional generation technologies, PV and wind tend to bid their generation output within wholesale electricity markets at or near the bottom of the merit order to ensure dispatch. Their integration into energy-only markets, therefore, has interesting and important implications for wholesale prices with the potential to cause revenue insufficiency, potentially leading to disincentives to market entry, resource inadequacy and system security challenges. The NEM is an energy- only wholesale market, without specific capacity market arrangements, and hence would seem particularly vulnerable to such impacts. Furthermore, while the NEM has excellent wind and solar resources across a large interconnected area, there are significant transmission limitations between market regions that might be expected to also have significant dispatch and price impacts. Only a few studies to date have explored generator revenues with high RE penetrations in the NEM (Vithayasrichareon et al., 2015; Wilkie et al., 2015), while the inclusion of market dispatch models and interconnector constraints has been limited (Hassan, 2015).

Furthermore, conventional generation technologies including thermal and hydro generators have inertia in their rotating turbine that is synchronously coupled to the system electrical frequency and therefore responds immediately and automatically to changes in frequency. Their presence in electricity systems helps to manage frequency and voltage stability, while also delivering sufficient power under fault conditions to trigger protection arrangements. However, there is no consensus on the amount of inertia that is required in a large system. Although short dispatch periods and fast frequency control (FFC) using batteries and power electronics can reduce the amount of inertia required, some minimum amount of synchronous inertia is believed to be required for power system management (Ela et al., 2014; Riesz, 2016). Ireland has a minimum synchronous generation requirement of 50% with proposals to reduce this to 25% (EIRGRID and SONI, 2017), and there is a formal proposal to introduce minimum inertia generation levels in the NEM (AEMC, 2017b). However, limiting the dispatch of low SRMC renewables in favor of higher SRMC conventional synchronous plant has economic implications for overall industry costs (Riesz and Elliston, 2016) as well as generator revenues, depending on the market arrangements for non-merit order dispatch and wind and PV curtailments (Daly et al., 2015).

This paper explores the market impacts of such a constraint with high RE in the NEM through the assessment of a possible pricing and generator side payment model. Firstly, a dispatch model is built using the market modelling tool PLEXOS (Energy Exemplar, 2017), which incorporates a range of high RE scenarios with interconnector constraints in the NEM; secondly, the potential impacts of a minimum synchronous generation requirement are explored; and thirdly, generator operational profits are assessed in these scenarios. Section 2 of this paper describes the method undertaken, Section 3 presents modelling results, which are discussed in Section 4, and finally conclusions are presented in Section 5.

2. Research design

2.1. Method Overview

The modelling method for this study involved the building of a number of base case generation portfolio scenarios in PLEXOS, with low RE cases validated by comparison with real market outcomes, the simulation of market dispatch for all base cases, the addition of a minimum synchronous generation constraint to the simulation, and data analysis. This overview is represented in Figure 1, and the steps described in more detail below. A low RE and four high RE generation portfolios, with aggregated generation by technology per NEM region, were used to model increasing RE penetrations for given annual historical regional demand profiles. These portfolios are summarized in Table 1.

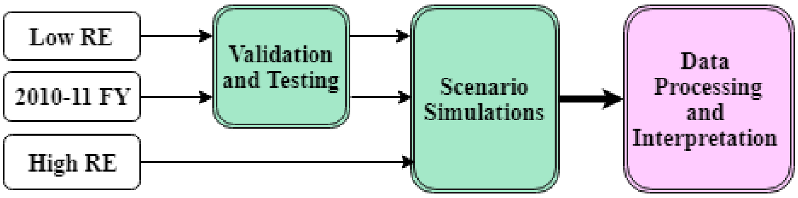


Figure 1 Overview of modelling methodology

The four generation portfolios for high RE scenarios were taken from a previous study which modelled economically optimal generator portfolios with key network constraints to achieve high RE penetrations in the NEM (Hassan, 2015). All four of these are based on the 2010-11 FY load, but seek to explore possible 2030 scenarios, and therefore assume the continued availability of certain existing generators with sufficient remaining service life into the future. The increasing RE contributions were achieved by the addition of PV and wind capacity in each region, given build limit assumptions, interconnector constraints, the minimization of RE spill and total system costs. The several GWs of rooftop PV in the NEM are omitted from modelling, but are present in the regional demand profiles used.

Table 1 Summary of scenarios simulated in PLEXOS and their key characteristics

Scenario	Time Period	Generation Portfolio	Dispatch Intervals	PV and Wind Inputs	Load Input
Low RE	Jun'16-Jul'17	Real 2016 Portfolio, AEMO	30 minute	Real Generation, NemSight	Real 2016 Load, NemSight
2010- 11 FY Real	Jun'10-Jul'11	Real 2011 Portfolio, AEMO	Hourly	Real Generation, NemSight	Real 2011 Load, NemSight
50% RE	Jun'10-Jul'11	Hassan's Study[1]	Hourly	ROAM Consulting[2]	Real 2011 Load, NemSight
60% RE	Jun'10-Jul'11	Hassan's Study[1]	Hourly	ROAM Consulting[2]	Real 2011 Load, NemSight

[1] High RE portfolio with interconnector constraints in NEM optimised in previous study (Hassan, 2015).

[2] ROAM Consulting's wind and PV MW traces for the 2010-11FY (ROAM Consulting, 2012).

70% RE	Jun'10-Jul'11	Hassan's Study[1]	Hourly	ROAM Consulting[2]	Real 2011 Load, NemSight
80% RE	Jun'10-Jul'11	Hassan's Study[1]	Hourly	ROAM Consulting[2]	Real 2011 Load, NemSight

Hassan's (2015) portfolios were used in this study to represent plausible medium-term future generation portfolios aimed at delivering high RE contributions. The high RE scenario names are derived from the penetrations achieved with no interconnector constraints. Because these are based on 2010-11 FY load and RE traces, they are compared to a scenario that involves the same assumptions and simplifications, with the real 2010-11 FY generation portfolio. An additional current Low RE scenario is based on the 2016-17 FY, and was included due to the increase in RE capacity and substantial decrease of coal capacity in the NEM since 2010. Coal retirements mostly resulted from infrastructure beyond end- of- life, although reduced market revenues may have also played a role in significant coal exit. The 2016-17 FY portfolio therefore presents a scenario closer to current market conditions for comparison.

2.2. Key Model Assumptions

The generator capacities in the portfolios for all scenarios described above are shown in Figure 2, with the high RE scenarios including some of the existing fossil fuel fleet and an increased RE capacity. Key generation physical and economic parameters were assumed for each technology including unit commitment considerations. Minimum operational stable levels, heat rate values, and starting times and costs were sourced from Acil Allen's Fuel and Technology Cost Review (ACIL Allen, 2014). Emissions factors, fuel costs, fixed and variable operating costs were sourced from BREE's Australian Energy Technology Assessment study (BREE, 2012). Typical unit sizes for combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT) and coal generation were calculated from average unit sizes existing in the NEM for each technology (AEMO, 2017). Ramping rates were calculated using specific plant ramping rate estimates from Acil Allen (ACIL Allen, 2014), which were normalized to each plants' capacity and then scaled up to each technology's typical unit size. The interconnectors modelled in this study are representative of existing constraints in the NEM as given by AEMO (2015). All scenarios include demand side participation levels estimated by AEMO in their National Electricity Forecasting Report 2016 (AEMO, 2016). Annual hydro energy limits were applied in PLEXOS using historical hydro generation per region over several years where hydro capacities have remained constant. The above assumptions were used as inputs in building the base cases in PLEXOS.

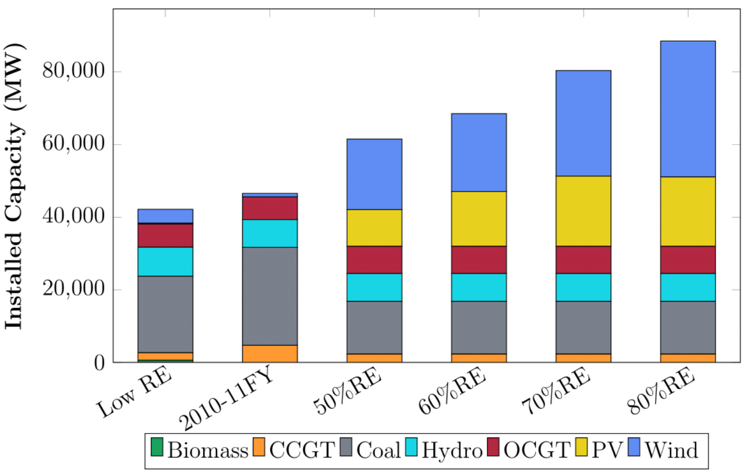


Figure 2 Installed generation capacities by technology in base cases

2.2.1. Renewable Energy Traces

In the Low RE and Real 2010-11 FY scenarios, real wind and PV generation aggregated by region was sourced from Nemsight (Creative Analytics, 2017) and input into the PLEXOS model. In the High RE penetration scenarios, however, regional 1MW traces were made for wind and PV from sub- regional traces to represent geographic variability of resources. Without this consideration of geographical averaging, the variability of the RE traces would be overestimated. Fourty two geographical polygons across the eastern side of Australia defined by ROAM Consulting for AEMO's 100% RE study (ROAM Consulting, 2012) were used to ensure consistency with Hassan's high RE penetration portfolios used in this study. The regional RE traces created in this study were weighted averages of all polygons in each region (state), with polygon contributions weighted by total energy generation in that polygon over the simulation period. That is, polygons that have a higher capacity factor contribute to the region trace more than polygons with less resources, proportionally. The resultant region wind and PV MW traces were inputs to the High RE scenarios in PLEXOS, where they were scaled up to the total capacity required in each RE contribution portfolio.

2.3. Validation and Testing

In this phase, the outputs of the Low RE and 2010-11 FY Real simulations were compared with real market outcomes to assess the model's relevance. In particular, competition parameters were adjusted to achieve pricing comparable to real market outcomes, and load curves were linearly scaled to achieve region unserved energy (USE) levels close to the national maximum standard of 0.002% (AEMC, 2017a), and to create some scarcity pricing events as experienced in real market conditions. The parameters co-optimised to achieve desired USE and pricing outcomes in the Low RE and 2010-11 FY Real scenarios were used in the High RE scenarios, although it should be noted that the USE was much lower in the High RE scenarios due to higher generation capacity (in order to achieve high RE penetration despite the presence of the existing fossil fuel generators).

2.4. Minimum Synchronous Generation Requirement

To explore the effect of a minimum synchronous generation requirement, a constraint was defined in PLEXOS, with coal, CCGT, OCGT, hydro and biomass generators defined as possible synchronous generation providers. Each region was constrained to provide at least 25% of generation from synchronous generators in every interval, effectively limiting instantaneous PV and wind penetrations to 75% per region. As the constraint causes out – of merit order dispatch, which is not accounted for in PLEXOS, wholesale pricing and generator revenues were calculated externally as follows.

In intervals where the constraint is binding, two marginal generators arise, the synchronous generator and the 'merit-order' generator, which may be asynchronous. This implies two simultaneous energy markets, where an additional MW must be provided by two generation sources, in proportions reflective of the constraint. In this study, the synchronous generation marginal price was assigned as the maximum offer price of dispatched generators. The region wholesale price was then calculated as the constraint- weighted sum of this offer price and the PLEXOS merit-order-only marginal price when the constraint is binding. When the constraint is non- binding, the merit- order marginal price was kept as the region wholesale price. A side payment was calculated for all generators dispatched due to the constraint at a clearing price below their offer, up to their offer price, and this was added to their operational profit results. This design is an exploration of constraint pricing discussed by Ela et al. (2014) and Caplan (2014), and represents 'make- whole' payments.

3. Results and Analysis

3.1. Base Cases

In the base cases (no synchronous constraint), increasing the wind and PV capacities led to the increase of RE penetration from 13% in the Low RE scenario to 70.5% in the 80% RE scenario (recall the names for the scenarios was based on energy penetration when no transmission constraints were modelled). Due to the increasing overall generation capacity in the portfolios, region USE levels decrease from 0.0015% to 4E-11%, wind and PV spill increases from 0 to 23%, and wholesale prices consistently decrease across all intervals. Figure 3 shows the energy contributions by technology for the base cases, with notable decrease in coal and gas generation and increase in PV and wind contribution.

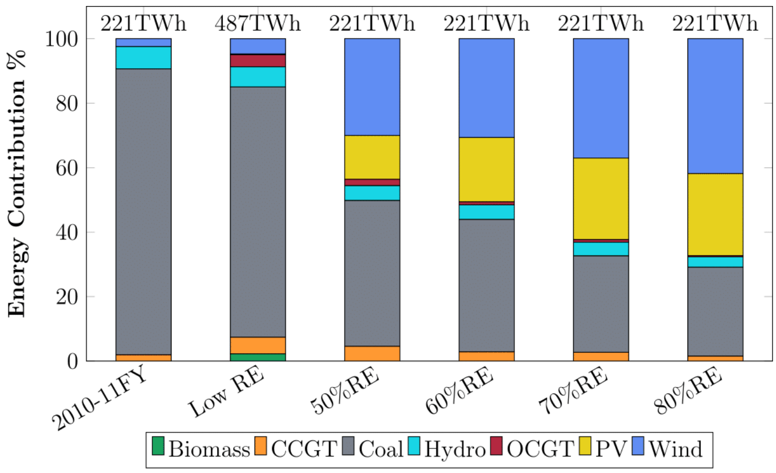


Figure 3 Energy contributions by technology for the base cases

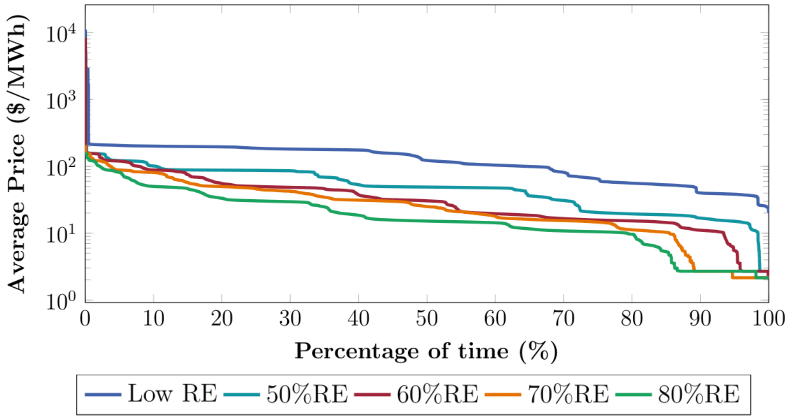


Figure 4 PDC comparison of base cases

The frequency distribution of wholesale prices can be represented by price duration curves (PDCs). These are compared for the base cases in Figure 4, and it can be observed that average wholesale prices decrease with increasing RE penetration even in the highest priced intervals. This generally causes a decrease in generator market revenues per unit of generation for all generators.

Figure 5 presents the operational profit per generation technology in each region, inclusive of market revenues and operational costs. Levelized Cost of Capital (LCOC) values were sourced for wind, PV, CCGT and OCGT (EIA, 2017), hydro (Blakers et al., 2017) and coal (LAZARD, 2016) and are indicated by the black lines. To ensure revenue sufficiency for new investment, LCOC should be lower than operational profit, which does not occur for the bulk of the generation fleet in most scenarios. While this comparison is illustrative of the potential viability of different technologies in these scenarios, caution should be exercised in interpretation. The LCOC is dependent on the achieved capacity factor, and this was unaccounted for in this comparison. Additionally, the physical viability for new investment given potentially promising profits has not been considered, and is a particularly relevant consideration for hydro. Furthermore, much of the existing infrastructure would be considered sunk investment, thus rendering the LCOC irrelevant.

Still, the operational profit results can be compared on a relative basis, with all generators' operational profits decreasing from the 50% RE scenario to the 80% RE scenario. Notably, modelling results suggest substantial profits to PV and hydro generation in SA and VIC, and OCGT in NSW, SA and VIC in the 50% RE scenario, while hydro in TAS and OCGT in QLD and TAS make minimal to zero profit per unit generation. Tasmanian OCGT is never dispatched in the 80% RE base scenario, and given its fixed operating costs, the model predicts an overall loss.

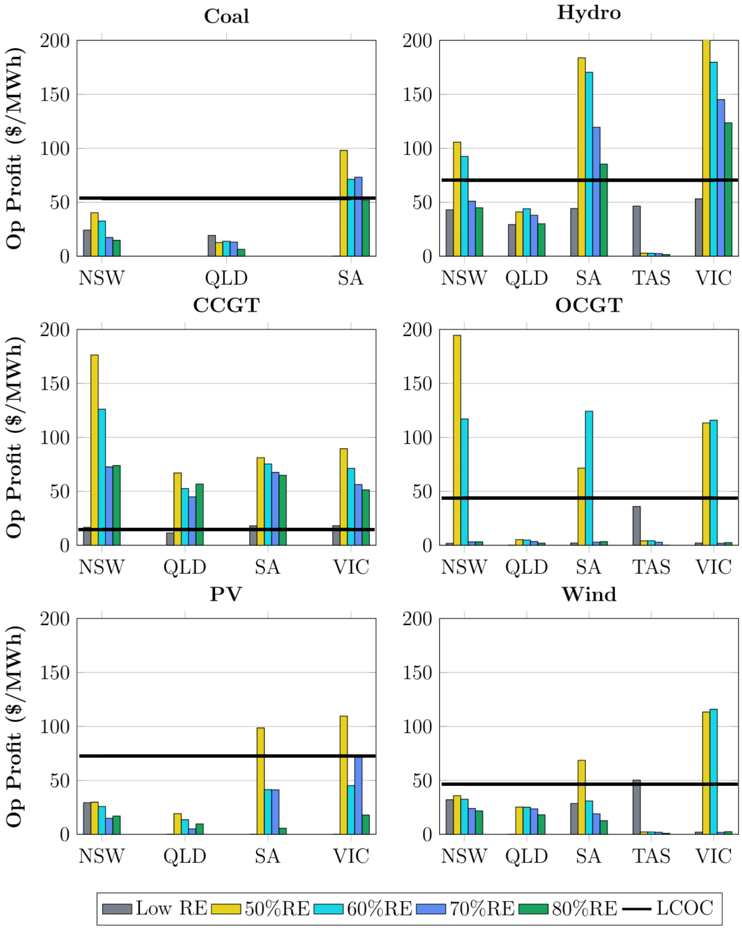


Figure 5 Generator operational profit for each technology by NEM region ($/MWh)

3.2. Minimum Synchronous Generation Constraint

A synchronous generation constraint of 25% was applied to the base cases, and its impact on market outcomes is presented below. Figure 6 shows the ratio of annual energy generation with the synchronous constraint compared with the base case for different generators in each RE contribution scenario, thereby indicating the relative change in generation. The synchronous generation constraint causes a significant increase in coal generation and high levels of wind generation curtailment, with little impact on PV and CCGT. In the 80% RE base case, wind generates over 84% of total Tasmanian generation, with many intervals where wind provides 100% of instantaneous generation. This domination therefore causes dramatic wind curtailment when a constraint is applied, especially in Tasmania, where hydro and OCGT generation increases up to three-fold to satisfy the constraint, whilst maintaining annual hydro energy limits. Hydro generation in all other regions is almost unaffected, as its dispatch occurs in the highest priced intervals due to its energy limit, whilst the price is generally very low in constraint binding periods as wind and PV generation dominates. This causes coal to be the preferential synchronous provider in the regions where it is available, as seen by its 20% generation increase in Queensland. Wind generation, which is higher on the merit order than PV due to its higher operational costs, is curtailed preferentially to PV when the constraint is binding, therefore bearing the majority of the constraint's impacts. This curtailment also increases total RE spill compared to the base cases by up to 25%, reduces RE penetrations by up to 9%, and increases relative emissions by up to 10% in the 80% RE scenario.

As RE contribution increases, the impact of the constraint on dispatch and pricing also increases. Wholesale prices increase with synchronous constraint compared to base cases, with intervals in which the constraint is binding and thus prices are increased, becoming more frequent as RE contribution increases. This is shown in Figure 7, where the percentage of intervals in which the constraint is binding increases with RE contribution. Figure 8 presents the Low RE and 80% RE PDCs with and without the constraint, and demonstrates that low prices where RE is the marginal generator disappear, and that there is increased scarcity pricing in the highest priced 0.05% of intervals, when the constraint cannot be met. Interestingly, the proportion of intervals of wholesale price increase does not equal the proportion of intervals in which the constraint is binding, resultant of unit commitment impacts on dispatch.

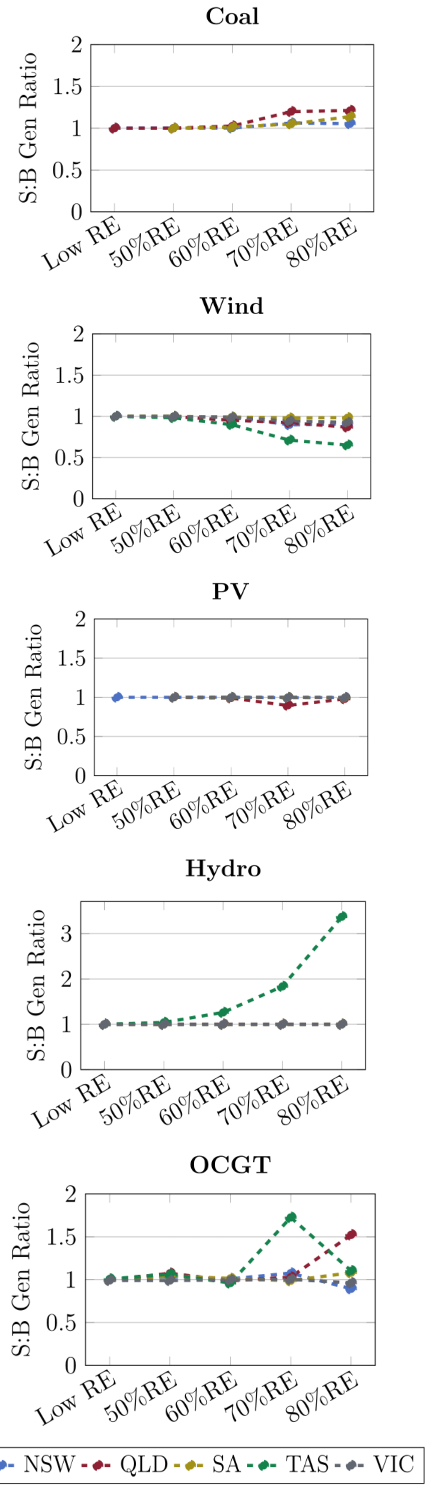
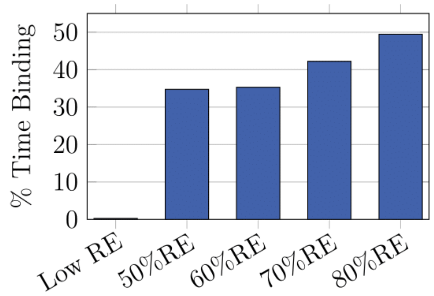


Figure 6 Synchronous constraint impact on energy generation

Figure 9 presents the ratios of total generator operational profits with and without the constraint. Wind total operational profit decreases with increasing RE contribution in every region, due to higher spill, while coal operational profits increase. It is interesting to note that although Tasmanian hydro dispatch is tripled with the constraint, its total operational profits steeply decrease. This is a result of its dispatch method in PLEXOS given the annual generation constraint, where rather than bidding price - quantity pairs in the market, hydro is dispatched only when prices are sufficiently high, given the energy limit constraint is satisfied. When made to generate due to the synchronous constraint, wholesale prices are very low due to high wind penetration, and its bid, which is used to calculate its side payment, appears as zero, thereby resulting in lower total market revenues than operational costs. This counterintuitive result highlights a key limitation associated with the side payment method utilised.

Notably, OCGT increases total operational profit by over 40- fold in the 80% RE scenario in NSW and VIC, while its generation in these regions decreases compared with the base case. This is likely due to its dispatch in the highest priced intervals, in which the wholesale price disproportionally increases compared to the base case, leading to higher market revenues. While the total operational profit for coal increases with the synchronous constraint in Queensland for the 50% and 60% RE scenarios, they are the same for the 70% and 80% RE scenarios as the bases cases, although coal generation increases. This is a result of an increase to operational costs, greater than the increase in market revenues, due to higher ramping and costs associated with starting and stopping generation more frequently.



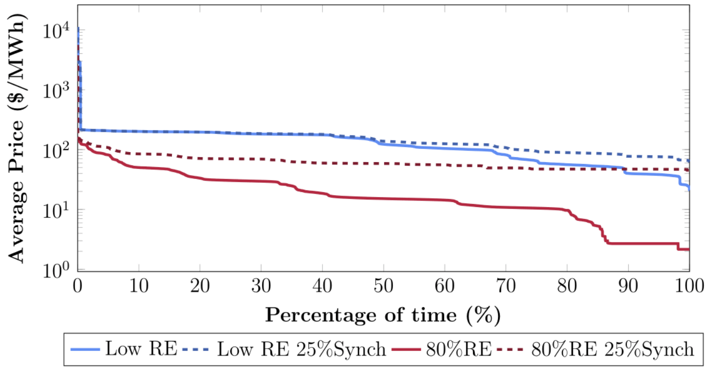


Figure 7 Synchronous constraint time binding

Figure 8 PDC showing synchronous constraint impact on region- averaged wholesale prices

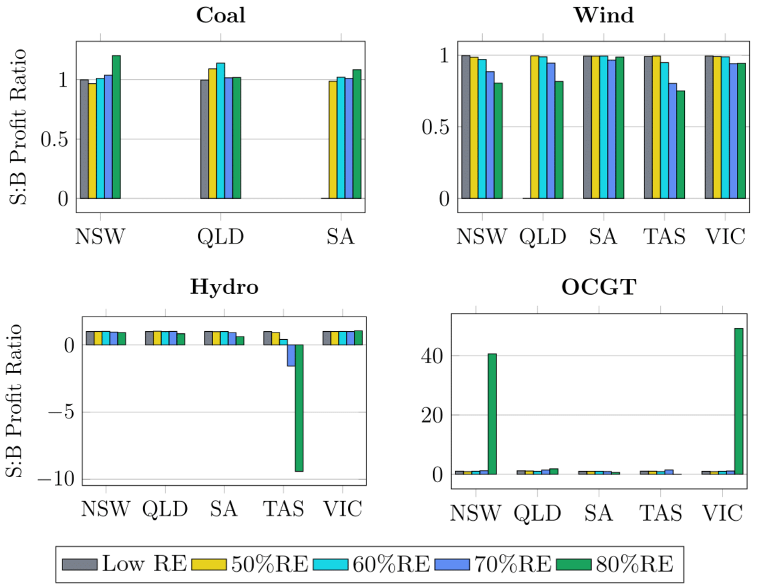


Figure 9 Synchronous constraint impact on total generator operational profit

4. Discussion

Caution should be exercised when considering the results presented in this study, especially in regard to absolute operational profits and generation proportions, given the challenges associated with dispatch modelling and strategic bidding around complex technical constraints, as well as uncertainty around key assumptions including generation portfolios and costs per technology. Nevertheless, the modelling suggests that wholesale prices and generator operational profits would decrease with increasing wind and PV capacity where current dispatchable generation not scheduled for retirement persists into the medium term. Furthermore, a synchronous generation constraint with market pricing and side payment arrangements along the lines incorporated in our study in the NEM could lead to substantial wind generation curtailment and an increase in coal generation compared to the non – synchronous base scenario, in regions where capacity is available. Average wholesale prices would increase with the constraint, and generator revenues would decrease for wind and increase for coal. This model indicates that insufficient market revenues may be available to most generators at very high penetrations of renewables with the current market design, and that the reduction in wholesale prices from increased RE entry could be largely offset if a synchronous generation constraint is applied.

The assumed driver of RE entry is important when considering high RE scenarios and in the design of the generation portfolios. This study assumes that current generation infrastructure with remaining service life in the NEM continues to operate into the future, and that in order to reduce fossil fueled generation, RE capacity will be added to this existing capacity. In a previous study that explored market impacts of high RE scenarios in the NEM, generation portfolios were designed to not only meet a RE penetration requirement, but also to achieve a consistent level of USE in order to reflect efficient investment and the presence of scarcity pricing, implicitly assuming a level of existing fossil fuel generator exit to allow sufficient entry of RE generation (Vithayasrichareon et al., 2015). While this study predicts lower wholesale pricing in all intervals as RE contribution increases, it involves quite simplistic modelling of the potential exercise of market power and does not consider the potentially nonlinear costs of flexible operation from fossil fueled generators with increased variable RE, thereby underestimating the likely wholesale prices at these times. These simplifications also lead to an underestimate of generator market revenues. Still, the exit of existing fossil fuel generators is likely required to achieve necessary scarcity periods which can lead to revenue sufficiency in high RE scenarios.

Given Ireland's and the AEMC's moves towards minimum synchronous generation level requirements as RE deployment rises, it is important to consider potential impacts on wholesale prices and generator revenues given such a constraint. A key part of synchronous generation constraint modelling is the wholesale pricing and side payment calculations. The market design modeled in this study allows generators dispatched out of merit order due to the constraint to cover their costs, and presents consumers with a price that is reflective of the marginal cost of providing a minimum level of synchronous generation. Not captured in the model, however, is that such a design would create additional competition in the synchronous provision market, where providers could exercise market power around scarcity, and wholesale prices would increase further, while merit order generators including PV and wind would not benefit.

A key area for further research is the detailed modelling of the complex competitive bidding behavior likely to result from a synchronous generation constraint. Additionally, the market outcome impacts from applying different pricing and side payment mechanisms are an intriguing and very important area to explore when considering synchronous generation constraints. It is foreseeable that other synchronous providers, for instance synchronous condensers, biomass and concentrated solar thermal generation will also participate in a synchronous provision market, yet these were excluded in this study and could also be the subject of future work.

5. Conclusions

In order to reduce Australia's greenhouse emissions, fossil fueled electricity generation must decrease, and renewable wind and solar PV are the most likely generation alternatives. This study modelled high RE scenarios in the Australian NEM with interconnector constraints and geographic diversity of wind and PV resources to investigate the potential impacts on energy dispatch, wholesale pricing and generator operational profits. The impacts on these outcomes from applying a minimum synchronous generation constraint was also explored. It was found that as RE contribution increases, wholesale prices decrease and all generator operational profits decrease, potentially causing future revenue insufficiency. Without the exit of many existing generators, the suppression of wholesale prices will create a disincentive for RE market entry without additional incentives. A synchronous constraint causes high levels of wind energy curtailment and an increase in coal generation. Careful design of pricing with non-merit-order dispatch and side payments is crucial for providing the right incentives for all generators whilst avoiding excessive wholesale prices and should be the subject of further detailed investigation.

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