ASIA-PACIFIC SOLAR RESEARCH CONFERENCE

PEER REVIEWED
ASIA-PACIFIC
SOLAR RESEARCH CONFERENCE

Finnian Murphy

Capacity Remuneration for Revenue Sufficiency in the Australian National Electricity Market with High Renewable Energy Penetrations

Finnian Murphy[1], Anna Bruce[1,2] and Iain MacGill[2,3]

[1]*School of Photovoltaic and Renewable Energy Engineering, UNSW, Sydney, Australia*
[2]*Centre for Energy and Environmental Markets, UNSW, Sydney, Australia*
[3]*School of Electrical Engineering and Telecommunications, UNSW Sydney, Australia*
E-mail: z5060459@ad.unsw.edu.au

Abstract

As renewable energy (RE) penetrations continue to grow in electricity industries around the world, some are now implementing mechanisms to renumerate different types of generation capacity as a means of ensuring future resource adequacy. This study investigates potential future operational revenue outcomes for different generation technologies in the Australian National Electricity Market (NEM) under different generation mix scenarios including high RE penetrations and storage. The study was undertaken with the PLEXOS Short-Term (ST) model, utilising modified scenarios based on those of the AEMO Integrated Supply Plan. A minimum dispatchable generation constraint was incorporated in the model to reflect the challenges of short-term frequency management. This constraint also provides some support for prices and hence revenue recovery. The impact of capacity remuneration mechanisms (CRM) to assist both dispatchable and non-dispatchable resources in achieving revenue sufficiency is also investigated.

Results highlight that synchronous generation profitability increases while utility solar profitability decreases with increasing penetrations of renewable energy (RE) resources for the scenarios that were investigated. This suggests that capacity remuneration may not be required for conventional plant, while there may certainly be challenges for variable renewable generation as penetrations climb under current market arrangements, in the absence of separate policy support.

1. Introduction

The mitigation of anthropogenic climate change demands decarbonisation of electricity industries globally. Significant progress to this end can be made through the widespread deployment of renewable energy (RE) resources. Wind and solar PV generation, in particular, have proven capabilities to reduce electricity sector emissions, and falling costs. However, due to their inherent variability, technical and economic issues arise with the integration of high penetrations of variable renewable energy (VRE) into generation mixes. The technical feasibility of future scenarios with high VRE penetrations has been explored in numerous studies including Riesz, Elliston, Vitharayasrichareon and MacGill (2016), Yan, Saha, Modi, Masood and , Mosadeghy (2015) and Cochran, Mai and Bazilian (2014); and overall cost analysis has been undertaken by Elliston, MacGill and Diesendorf (2014) and Deason (2018). However, the deployment of high-penetration RE generation portfolios requires significant upfront investment, which is strongly dependent on generator revenue projections.

Recent modelling for the Integrated System Plan (ISP) conducted by the Australian Energy Market Operator (AEMO) suggests that generation portfolios on the order of 80% renewable energy are feasible in the Australian National Electricity Market (NEM) by 2040. While the NEM's geographically-extensive network and Australia's rich solar and wind resources make high VRE penetrations possible, technical and economic issues arise. In particular, given negligible operating costs, VRE tends to pull down the marginal dispatch price when generating, potentially resulting in reduced revenue outcomes for all generators, and perhaps insufficient revenue to incentivise future generation investment, or even for some existing generators to continue participation in the sector. Both the departure of existing generators and insufficient investment can lead to resource inadequacy difficulties for the electricity sector. Given the projected retirement of significant synchronous coal plant capacity in the NEM over coming years due to their age and growing maintenance challenges, frequency management is also likely to become more challenging. These issues may necessitate changes to existing market arrangements to ensure a generation portfolio that can deliver affordable, clean, secure and reliable electricity supply.

The question of revenue sufficiency has seen considerable discussion including in the context of the Australian National Electricity Market (NEM) where Wilkie (2015) and Samocha (2017) recommend that electricity market design changes may be necessary to drive resource adequacy and achieve such generation mixes in the NEM. However, NEM operation continues to evolve as growing levels of wind and solar are deployed, while modelling exploring outcomes under different market arrangements remains incomplete.

The potential for revenue insufficiency in energy-only markets stems in part from the unique characteristics of VRE resources. These generators have no fuel costs and therefore very low operating costs, tend to place very low bids compared to fossil fuel-dependent generators, and are hence dispatched preferentially. In intervals featuring substantial levels of VRE dispatch, wholesale electricity prices tend to be lower since the interval's market clearing price, set by the bid of the marginal generator, is reduced as more expensive generators are pushed out of dispatch (Hildmann, Ulbig and Andersson, 2015). With high VRE penetrations, premature generation capacity exit or lack of investment becomes a risk in energy-only markets, potentially jeopardising the reliability and security of electricity supply.

This paper investigates revenue sufficiency in and potential market arrangement changes to future NEM scenarios with high-penetration VRE generation portfolios. The PLEXOS Integrated Energy Model (Energy Exemplar, 2018) was selected, given its widespread use by market operators in international electricity jurisdictions, including the Australian Energy Market Operator (AEMO) (AEMO, 2018). Four scenarios are devised in PLEXOS comprising of existing generating plant currently in the NEM combined with new VRE resources allocated to Renewable Energy Zones (REZ), in accordance with results produced from AEMO's Integrated System Plan (ISP) (AEMO, 2018). Base cases are first simulated in PLEXOS before undergoing modification to alter revenue outcomes and then data analysis to determine revenue trends and implications for various generating technology classes.

Section 2 of this paper reviews relevant literature and provides a theoretical basis for the study; Section 3 presents the modelling method used; Section 4 contains results and analysis and Section 5 presents the study's conclusion.

2. Context

2.1. Revenue Sufficiency in Energy-Only Markets

In energy-only markets such as the NEM, it is necessary for generators to recover their long-run marginal cost (LRMC) – that is, their annualised capital repayment and fixed operating and maintenance (FO&M) costs as well as operating costs - through wholesale spot market revenue (along with derivative contracts based on future spot prices) in order to achieve overall profit. In markets with efficient (that is industry-wide least cost) generation mixes, all generators theoretically should receive revenue that appropriately recovers all capital and operating costs when all participants offer in at their marginal (operating) cost, and scarcity is set according to the value of lost load (VoLL).

Some technology classes are highly dependent for feasibility on scarcity pricing during times of insufficient generation resulting in unserved energy (USE) in the NEM. Substantial proportions of annual revenue can be earned in a few time intervals of scarcity pricing (Vithayasrichareon, Riesz and MacGill, 2016). One challenge here is the difficulties of permitting, indeed requiring, periods of scarcity, even if this the most efficient outcome – at some point, the loss of value associated with that final, very small, unserved load is less than the cost of supplying it. In a similar way, if the market price cap (MPC) is too low, and hence an inefficient price signal to drive sufficient investment, generators may find recovery of capital costs impossible. This phenomenon has been dubbed the missing money problem (MMP) (Hildmann et. al, 2015; Newbery, 2015). The MMP threatens revenue sufficiency for high-SRMC generators which are displaced from the merit order, and for capital-intensive technologies with negligible operating costs including solar and wind which therefore tend to bid low (Hildmann et. al, 2015). Measures to mitigate revenue insufficiency and find solutions to the MMP in energy-only markets include capacity remuneration, carbon pricing, emissions constraints, MCP increases and minimum dispatchable generation constraints (Hildmann et. al, 2015; Vithayasrichareon et. al, 2016; Samocha, 2017).

2.2. Minimum Synchronous Generation Requirements and Revenue Sufficiency

Generators whose rotational frequency is directly coupled to the grid frequency (i.e. 'synchronous generators') provide physical inertia, which dampens rapid frequency changes, thereby helping to maintain system stability and reducing the need for fast frequency management services. However, as VRE deployment increases, the proportion of synchronous generation online tends to decrease, increasing the risk of stability issues (AEMC, 2018). Samocha (2017) modelled the implementation of a minimum synchronous generation constraint of 25% in a future high VRE NEM, based on settings in Ireland's electricity industry (O'Sullivan, Rogers, Flynn, Smith, Mullane, O'Malley 2014), and observed improved revenue recovery for participating synchronous generators. The Australian Energy Market Commission (AEMC), in their draft report reviewing frequency control frameworks in the NEM, suggests that at least 30% of dispatched generation for any given interval should be capable of mitigating frequency deviations (AEMC, 2018).

2.3. Capacity Remuneration and Revenue Sufficiency

The purpose, design and stage of implementation of capacity remuneration mechanisms (CRM) in electricity markets around the world have been qualitatively reviewed in literature (Betz, Cludius and Riesz, 2015; Byers, Levin and Botterud, 2018). The impact of capacity markets on revenue sufficiency with high VRE penetration is recieving particular attention (Betz et. al, 2015). In addition to assisting generators to recover fixed costs (especially in markets featuring low MPCs), capacity mechanisms can send efficient investment signals to drive resource adequacy in order to meet projected demand increases or environmental commitments. Markets with CRMs are typically characterised by low competitive generation bidding behaviour that tends towards market theoretic conditions (limited forced price variation due to bidding close to SRMC) and lower MPCs, since generators can rely on capacity remuneration to cover fixed costs while electricity wholesale recovers at least the VO&M costs (for non-marginal generation) (Betz et. al, 2015; Chattopadhyay and Alpcan, 2016).

The traded product in CRMs can be either: physical plant generating capacity (typically one MW) known as a 'capacity credit' declared available for a particular timeframe (usually a year); or financial instruments including reliability options. To incentivise efficient operation, especially in scarcity periods, arrangements can be made to either penalise non-availability or additionally compensate consistently-performing generators. Reliability options are essentially call options similar to cap contracts traded in energy-only markets: generators sell these options typically to a centralised authority (i.e. market operator) and pay the authority the difference between wholesale electricity spot price and a pre-specified strike price during intervals when the spot price exceeds the strike price; this has significant revenue ramifications for scheduled generators unavailable during these critical periods (Betz et. al, 2015). Markets combining electricity wholesale with reliability options essentially operate in a similar fashion to energy-only markets with a specified level of compulsory contracting and have been referred to as Capacity-Energy Markets (Chattopadhyay et. al, 2016).

In some United States electricity markets featuring CRMs, VRE resources, in addition to dispatchable resources, are assigned capacity credits. VRE resources are awarded remuneration up to a particular percentage of their nameplate capacity, calculated through a variety of methodologies depending on the jurisdiction in question. Historical output during required performance hours (reflecting peak loads and shortage conditions) serves as a basis for most jurisdictions in determining the qualifying capacity value of VRE resources (Byers et. al, 2018). Boute (2012) found that capacity-based financial support can facilitate efficient integration of VRE via reducing investor exposure to the risk of periods of poor local wind or solar resource. The study in this paper seeks to address some of the limitations of previous work on this issue in the NEM, in particular given the recent release of the AEMO ISP and its relatively high VRE penetration scenarios, as well as recent developments in utility battery storage demonstrating its ability to provide extremely rapid frequency response.

3. Method

Four scenarios were modelled in the PLEXOS Integrated Energy Model (Energy Exemplar, 2018), comprising of existing generating plant currently in the NEM combined with new VRE resources allocated to Renewable Energy Zones (REZ), in accordance with results produced by AEMO's ISP modelling (AEMO, 2018). Base cases with 50-80% RE were simulated in PLEXOS using the EELPS solver, then again with a minimum dispatchable generation constraint, and analysed to determine revenue trends and implications for various generating technology classes.

3.1. Generation Portfolios

Four base-case generation portfolios were created based on the results of ISP capacity expansion modelling over the years 2018-2050 completed by AEMO (2018). Each generation portfolio is based on the results of a particular year selected based on RE contribution percentage by installed capacity, as presented in Table 1. Generation portfolios used in PLEXOS model. Hydro, wind, utility PV and rooftop PV were included in the penetration percentage calculation, and storage option penetrations were excluded.

Table 1. Generation portfolios used in PLEXOS model

Scenario	Timeframe	Source
50% RE	June 2023-July 2024	ISP DLT Results
60% RE	June 2029-July 2030	ISP DLT Results
70% RE	June 2034-July 2035	ISP DLT Results
80% RE	June 2039-July 2040	ISP DLT Results

Figure 1. Generating capacity by technology class for high VRE penetration scenarios 1 indicates the portfolio composition by installed capacity for each technology class.

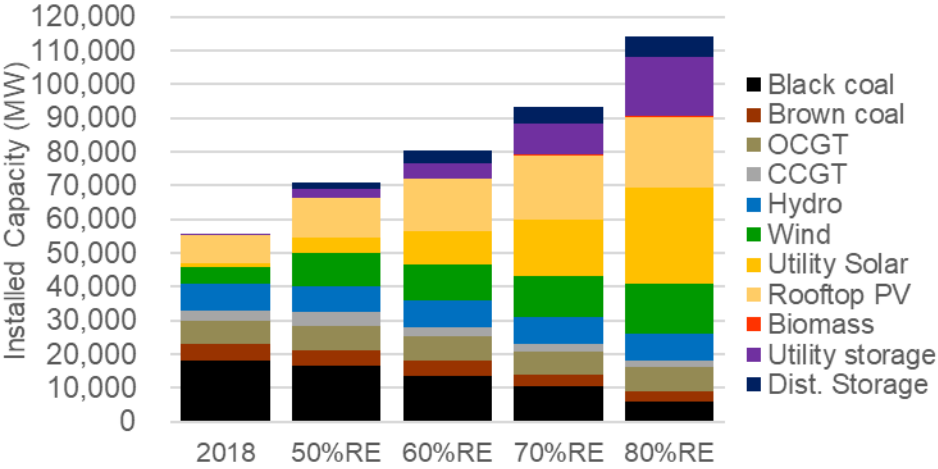

Figure 1. Generating capacity by technology class for high VRE penetration scenarios

AEMO's ISP model contained generator characteristics and properties for all current existing, committed and advanced generators in the NEM, as well as estimates for new plant of various technologies (ACIL Allen, 2014). Using the Neutral scenario generation outlook figures for each technology in each NEM region (AEMO, 2018), new generating plant were added to the model, equal to the penetration of RE for that year. Some generator 'Properties' like ramping characteristics and costs were sourced from the ACIL Allen Review (2014). New build VRE for each scenario was introduced to REZ 'Objects' via 'Memberships' in the corresponding REZ (AEMO, 2018).

The capabilities of transmission infrastructure in the NEM will likely be crucial to capitalising on geographically-diverse VRE resources through increased inter-regional energy transfers (Hassan, 2015). Existing NEM interconnector transmission capacities were used in this study, with augmentation according to ISP modelling undertaken by the Australian Energy Market Operator (2018) in the case of the higher-penetration RE scenarios in later years.

3.2. Minimum Dispatchable Generation Constraint

For this study, a minimum dispatchable generation constraint of 30% was modelled for each of the four RE penetrations, in line with recommendations made by the AEMC that at least this proportion of dispatched generation for any given interval should be capable of mitigating frequency deviations (AEMC, 2018). Resources eligible for participation in this constraint are considered to be: coal, gas, utility hydro, pumped hydro and biomass generators, which provide instantaneous physical inertia; and additionally batteries, both distributed and utility-scale, given the capability of their power electronics of providing fast frequency response (FFR) and emulated inertia (AEMC, 2018).

3.3. Load Scaling

In order to produce realistic market outcomes from the model, load was scaled to achieve USE levels as close as possible to AEMO's minimum Reliability Standard of 99.998% delivered energy in each region. While this tuning was successful in achieving some instances of scarcity pricing, average wholesale prices increased substantially throughout the simulation horizon at least in part due to increasing scarcity pricing periods. In addition, since new capacity procurement over the 20 year modelling horizon is lumpy, and therefore non-linear for each technology class for each region, the different RE penetration scenarios resulted in different USE levels at different stages of the simulation horizon. This was confirmed during preliminary attempts at scenario optimisation through load scaling of different ISP generation outlook years. Given that different regions in different years required load scalars with up to 20% variability to produce USE levels of approximately 0.002%, significant price distortion occurred and a comparison of pricing and revenue outcomes between the four scenarios was rendered invalid. In the end, eight simulation runs (50-80% base case and 50-80% dispatchable constraint) were used without any load/price modification. Note that this means great care is required when comparing price outcomes across the eight runs. Nevertheless, the modelling runs do highlight some key issues for revenue sufficiency in a high VRE future under different assumptions of penetrations, dispatch requirements and CRM approaches.

3.4. Base Cases

Dispatch for each base case was modelled using PLEXOS's LT and MT schedules over a one-year horizon. Figure **3** presents generation-weighted price-duration curves across the NEM for the 4 base case simulations.

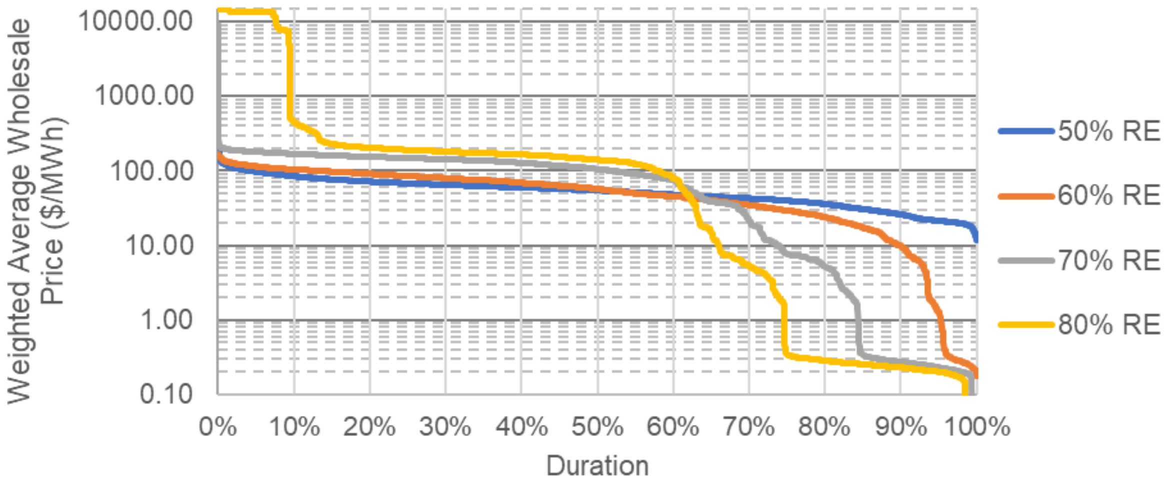

Figure 3. Generation-weighted NEM price-duration curves for base cases

Figure 4 and Figure 5 display box-and-whisker plots indicating maximum, upper quartile, median, lower quartile and minimum net operating profitability by generator class for the 50% RE and 70% RE base cases respectively. Net profitability was calculated by taking the sum of operational profit (subtracting operational cost from clearing price) in all simulated intervals, from which fixed costs were subtracted.

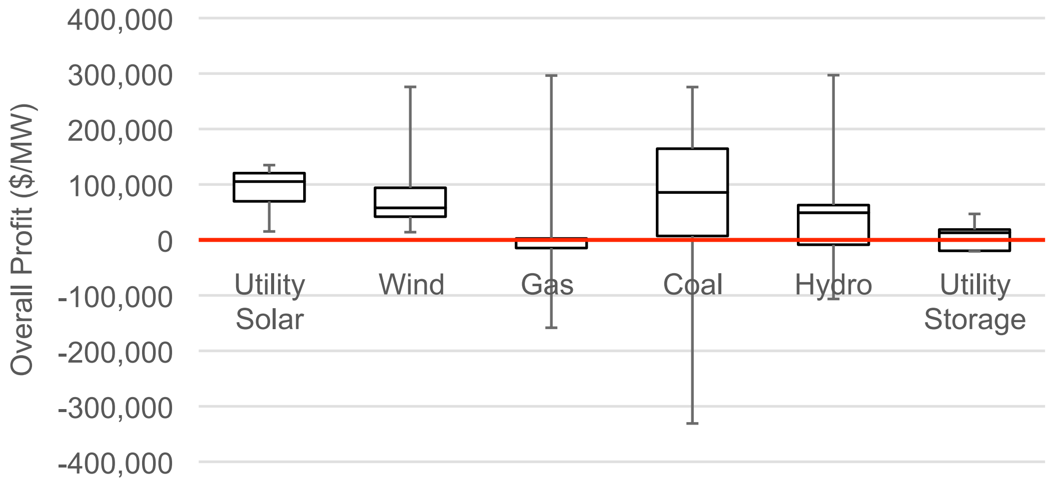

Figure 4. Overall annual operating profit per MW capacity in 50% RE scenario, base case

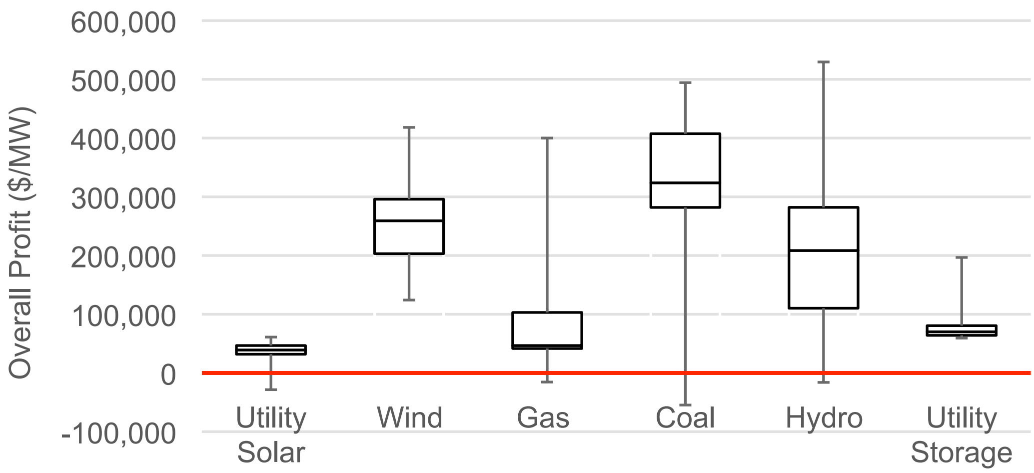

Figure 5. Overall annual operating profit per MW capacity in 70% RE scenario, base case

As a result of the mismatch between generation and demand (discussed in section 3.3 above), regional price distortions and unrealistic scarcity pricing events were produced in some scenario simulations (e.g. 80% RE). Hence the results of this study should be taken as indicative. While absolute revenue values should not be relied upon, general trends can be observed and are informative.

Interpreting the box-and-whisker plots, if a substantial proportion of the plot for each technology class lies below $0/MW, i.e. the median generator incurs an operating loss, this indicates either generator exit is likely or there is a low probability of such capacity being originally procured.

Notable trends to observe are:

- Diminishing revenue solar between the 50% and 70% RE scenarios, as increasing solar penetrations suppress wholesale prices throughout daylight hours;
- Increasing revenue for gas, coal and hydro classes between 50% and 70% RE. Given decreasing synchronous generation penetrations in Figure 1 and increasing wholesale prices in 60% of simulated intervals in Figure 2 with increasing RE penetrations, it is likely that more expensive generators are relied upon to meet demand more often. This

enables non—marginal generators in these classes to achieve higher revenue as RE penetration increases;

- Wind revenue is assisted by this effect, since it generates outside daylight hours and can exploit higher prices set by increasingly-expensive marginal synchronous generators;
- As daytime prices are increasingly suppressed with increasing RE penetrations, and evening prices raised by dispatchable resources with higher VO&M costs, utility storage units exploited price differences, becoming increasingly profitable in higher penetration scenarios;
- Generally, sufficient profits are achieved for each technology class to negate the need for additional remuneration (the gradually reducing investment signal for solar would likely culminate in a lower solar penetration which may be the more efficient outcome depending on storage availability and other flexibility options). For gas and utility storage classes in the 50% RE base case, however, the medians lie below and slightly above the break-even point respectively due to suboptimal portfolio composition for this scenario.

Note that the 60% RE scenario results were intermediate between the 50 and 60% RE scenarios and in the interest of the length of this paper were omitted, and the 80% RE scenario was exempted from analysis given the unreliability of its results due to unrealistically high USE incidence.

3.5. Minimum Dispatchable Generation Constraint

For the second set of simulation runs, the competitive bidding parameters were removed so that dispatch was based on short-run marginal cost, and the MPC was lowered in each region from $14500/MWh to $1000/MWh, so as to more closely emulate actual capacity-energy market conditions. The dispatchable generation constraint was revised from 30% to 25% following inspection of dispatch results for the 70% RE and 80% RE base scenarios, wherein excessive USE spikes were occurring due to insufficient capacity being available to constitute 30% of dispatch in every interval.

Figure 6 presents generation-weighted price-duration curves across the NEM for the 4

Figure 8 and Figure 10 indicate profitability by generator class for the 50% RE and 70% RE simulations respectively.

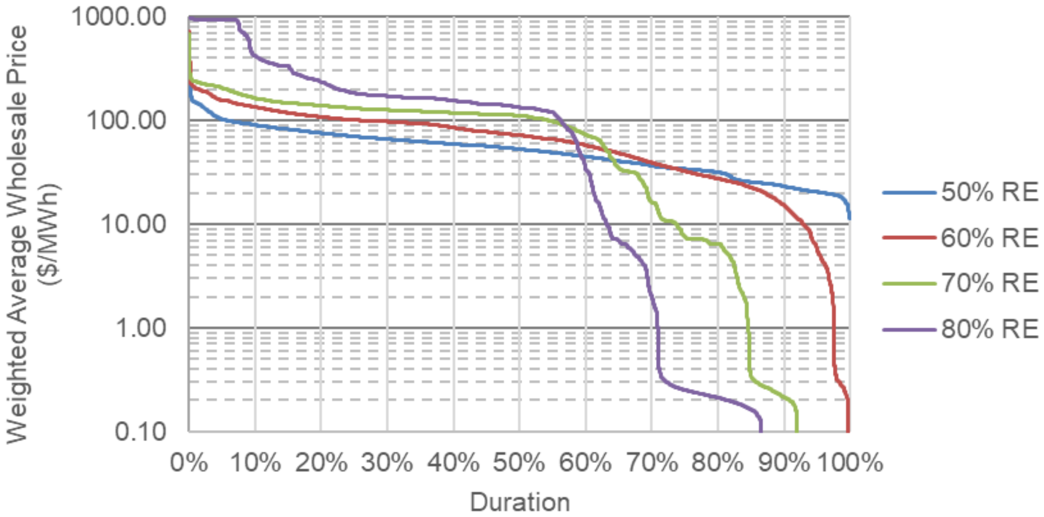

Figure 6. Generation-weighted NEM price-duration curves for dispatchable constraint cases

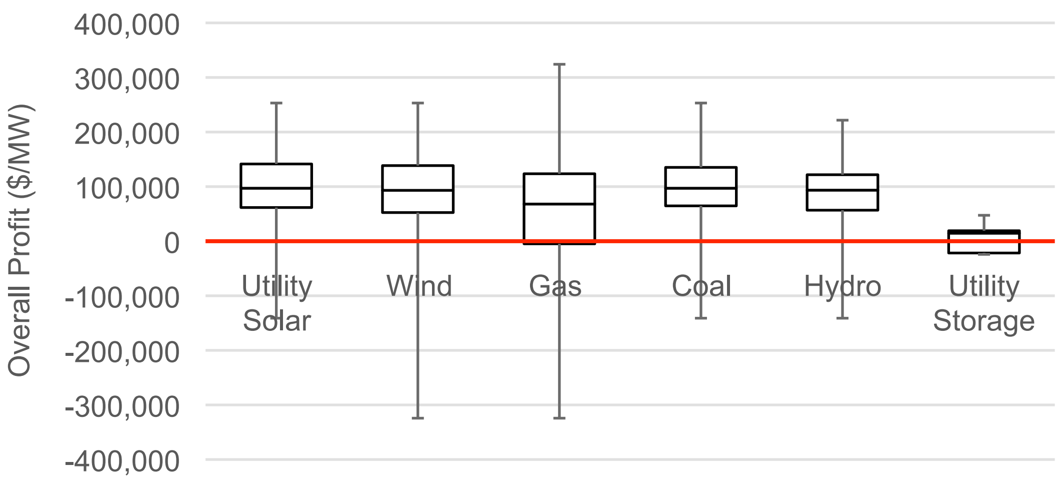

Figure 8. Overall annual operating profit per MW capacity in 50% RE scenario, dispatchable constraint

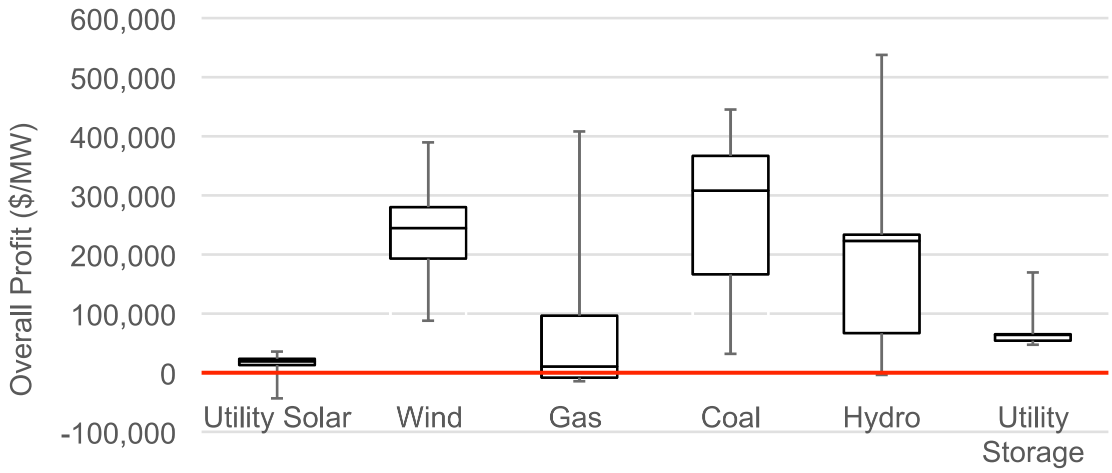

Figure 10. Overall annual operating profit per MW capacity in 70% RE scenario, dispatchable constraint

Intervention pricing was considered in these cases as a revenue insufficiency mitigation option, wherein those dispatchable generators dispatched out of merit order would be awarded a parallel marginal price, enabling the forced-on non-marginal dispatchable generators to make operating profit in intervals wherein the constraint was binding. However, given consistent profits across technology classes, these payments were not awarded. The differences between results in the 50 and 70% RE base and constrained cases (generally lower profit for both VRE and dispatchable resources in the latter) can be attributed to VRE resources being displaced from the merit order and dispatchable resources being forced on without receiving an appropriate marginal price, since PLEXOS does not recalculate and apply this by default (payments must be made exogenously).

3.6. Capacity Remuneration

Since PLEXOS does not allow modelling of a capacity market, to explore the impact of a CRM, preliminary analysis was undertaken as displayed in Figure 12 to value capacity based on availability during the 90th percentile of load. A net load curve was produced wherein VRE contributions were subtracted, serving as a basis for remunerating the availability of dispatchable resources in times of high demand. The VRE contribution is the subtraction of the net load-duration curve from the overall load-duration curve, which can be used to assess and quantify the value of VRE capacity in high load intervals. While this effectively compares different dispatch hours, it can provide an indication of how the load peak that needs to be addressed by dispatchable generation has been partially offset by VRE generation. These relations can be utilised to value capacity for various generator types and calculate penalties for unavailability of individual resources during instances of high demand.

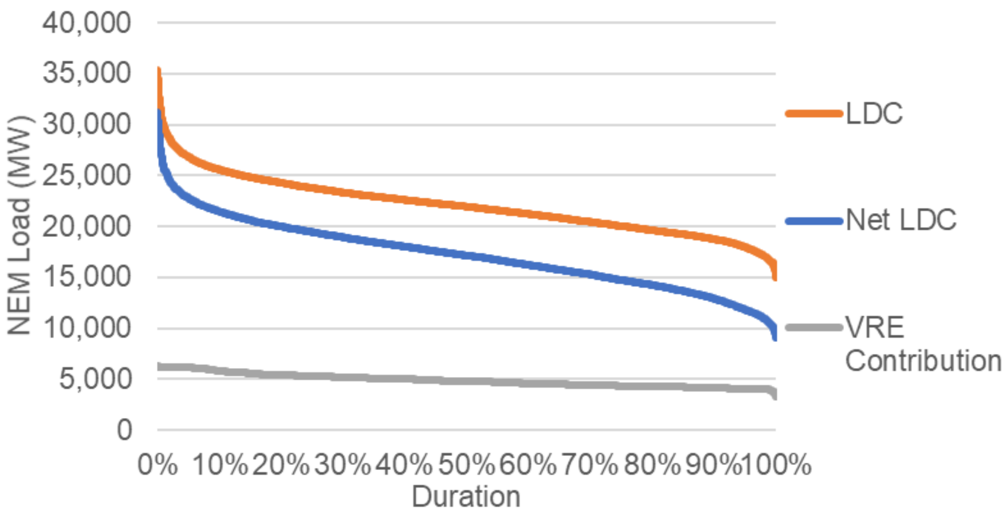

Figure 12. NEM load-duration curves, 50% RE scenario, dispatchable constraint

4. Conclusion

This paper aimed to investigate the ability of generators to recover costs in the NEM with high penetrations of VRE. The results indicate that cost recovery may only be an issue for a minority of generators in both the base cases and in scenarios with the imposition of a minimum dispatchable generation constraint (and emulation of perfect market conditions). In the base cases, identified trends were the increasing returns for synchronous generators, wind resources and utility-scale storage, and diminishing returns for utility solar, for increasing penetrations of VRE resources. Similar trends were observed in the latter scenarios wherein the MPC was lowered and a minimum dispatchable generation constraint of 25% was introduced, however the synchronous and wind resources received less revenue than those in the base cases since PLEXOS does not automatically account for intervention pricing (for intervals in which the constraint was binding there was no marginal price change). The profitability of utility solar tending to zero indicates that ISP generation projections for this class may be excessively high and in actual circumstances such levels of investment may not be procured.

Model validation was limited given the complications associated with load scaling and bid mark-ups, which is significant given how comprehensively documented the MMP is in literature and the reliance of many generators on scarcity pricing for cost recovery: hence the modelling completed cannot be fully validated. Given operating profitability outlined in the Results Section above, the case for a capacity remuneration mechanism is not clearly made, though several options were identified and explored. Summarily, though the results indicate consistent generator profitability, further modelling needs to be undertaken to confirm the validity of these results and apply the recommended CRMs, and dispatchable constraint intervention pricing, to other dispatch simulation results where applicable.

5. References

ACIL Allen. (2014). *Fuel and Technology Cost Review*. Retrieved from http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions

AEMC. (2018). *Frequeny Control Frameworks Review. Draft Report*.

AEMO. (2013). *100 Per Cent Renewables Study - Modelling Outcomes*. Retrieved from http://climatechange.gov.au/sites/climatechange/files/documents/08_2013/100-percent-renewables-study-modelling-outcomes-report.pdf

AEMO. (2017). *Advice to Commonwealth Government on Dispatchable Capability*. Retrieved from https://www.aemo.com.au/-/media/Files/Media_Centre/2017/Advice-To-Commonwealth-Government-On-Dispatchable-Capability.pdf

AEMO. (2018). *Data Dashboard*. Retrieved from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard

AEMO. (2018). *Integrated System Plan Database*. Retrieved from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database

AEMO. (2018). *Integrated System Plan for the National Electricity Market* . Retrieved from http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP

B Elliston, I. M. (2014). *Comparing least cost scenarios for 100% renewable electricity with low emission fossil fuel scenarios in the Australian National Electricity Market*. Retrieved from http://dx.doi.org/10.1016/j.renene.2013.12.010

Boute, A. (2012). *Promoting renewable energy through capacity markets: An analysis of the Russian support scheme*. Retrieved from http://dx.doi.org/10.1016/j.enpol.2012.03.026

C Byers, T. L. (2018). *Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves*. Retrieved from https://doi.org/10.1016/j.tej.2018.01.006

D Chattopadhyay, T. A. (2016). *Capacity and Energy-Only Markets under High Renewable Penetrations*.

Deason, W. (2018). *Comparison of 100% renewable energy system scenarios with a focus on flexibility and cost*. Retrieved from https://doi.org/10.1016/j.rser.2017.10.026

Energy Exemplar. (2018). *PLEXOS Simulation Software - Energy Exemplar*. Retrieved from https://energyexemplar.com/products/plexos-simulation-software/

Hassan, A. (2015). *Challenges and Opportunities for Transmission Network Investment with High Renewable Penetrations in the National Electricity Market*.

J Cochran, T. M. (2014). *Meta-analysis of high penetration renewable energy scenarios*. Retrieved from http://dx.doi.org/10.1016/j.rser.2013.08.089

J O'Sullivan, A. R. (2014). *Studying the Maximum Instantaneous Non-Synchronous Generation in an Island System - Frequency Stability Challenges in Ireland*.

J Riesz, B. E. (2016). *100% Renewables in Australia: A Research Summary*. Retrieved from http://ceem.unsw.edu.au/sites/default/files/documents/100pcRE-researchsummary-2016-03-02a.pdf

L Marshall, A. B. (2014). *De-Risking Utility-Scale Solar*. Retrieved from http://apvi.org.au/solar-research-conference/wp-content/uploads/2015/04/3-Marshall_APVI_Policy_PeerReviewed.pdf

M Hildmann, A. U. (2015). *Empirical Analysis of the Merit-Order Effect and the Missing Money Problem in Power Markets with High RES Shares*.

Newbery, D. (2015). *Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors*.

P Vithayasrichareon, J. R. (2016). *Impact of High Variable Renewable Generation on Future Market Prices and Generator Revenue*. Retrieved from http://ceem.unsw.edu.au/sites/default/files/documents/PES_APPEEC_2015_-_Revenue_withoutdiffMPC.pdf

R Betz, J. C. (2015). *Capacity Remuneration Mechanisms Overview, Implementation in Selected Jurisdictions and Implications for Switzerland*.

R Yan, T. K. (2015). *The combined effects of high penetration of wind and PV on power system frequency response*. Retrieved from http://dx.doi.org/10.1016/j.apenergy.2015.02.044

Samocha, S. (2017). *Generator Revenue in the Australian National Electricity Market with High Renewables and a Synchronous Generation Constraint*.

Wilkie, O. (2015). *Revenue Sufficiency in the Australian National Electricity Market with High Penetrations of Renewable Energy*. Retrieved from https://www.researchgate.net/publication/292608748_Revenue_Sufficiency_in_the_Australian_National_Electricity_Market_with_High_Penetrations_of_Renewable_Energy

Acknowledgements

The authors extend gracious thanks to Zoe Hungerford and Shira Samocha for their patient and beneficial instruction regarding the use of the PLEXOS Integrated Energy Model in the early stages.

Acknowledgements and thanks are also extended to Energy Exemplar for their academic licensing of PLEXOS, and particularly to Nathan from Support, without whose tireless diagnostic efforts this thesis would never have been completed.