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Rob Selbie

Assessing the Potential Value of Utility-Scale Energy Storage Arbitrage in the Australian National Electricity Market

Rob Selbie[1], Anna Bruce[1], Iain MacGill[2]

[1] *School of Photovoltaic and Renewable Energy Engineering, UNSW, Sydney Australia*

[2] *Centre for Energy and Environmental Markets School of Electrical Engineering and Telecommunications, UNSW, Sydney, Australia*

E-mail: rrcselbie@gmail.com

Abstract

Energy storage is of growing interest to participants in the Australian National Electricity Market (NEM) across a range of deployment scales and hence market segments, driven by a number of factors including new battery technologies and growing renewable generation penetrations. This study assesses the specific application of utility-scale energy storage for wholesale energy arbitrage in the NEM – that is, the use of large centralised storage to shift energy from periods of lower value to periods of higher value. To investigate how energy storage arbitrage value is affected by different factors that are likely to shape the future NEM, a scenario investigation of energy storage was performed using PLEXOS, a widely used modelling simulation tool. The PLEXOS model was adapted from the 2014 National Transmission Network Development Plan (NTNDP) provided by the Australian Energy Market Operator (AEMO). The results indicate that factors such as fuel pricing, possible policy interventions such as carbon pricing, and high renewable energy capacity penetrations may all significantly impact the value of wholesale energy arbitrage, and in potentially surprising ways. In particular, decreasing black coal or natural gas fuel prices in the model resulted in lower arbitrage revenue. Conversely, carbon prices of \$60/tCO_{2e} or greater resulted in increased value for utility-scale storage arbitrage, while high combined PV/wind penetrations in the generation mix generally resulted in significant arbitrage revenue increases in NSW, QLD and SA but not VIC. Analysis of these modelling results highlights the impacts of existing generation mixes and transmission interconnector constraints on outcomes in the different states, and provides useful insights that can assist energy storage operators and other NEM participants to better plan for future challenges and opportunities associated with energy storage in the NEM, while also guiding policy makers.

1. Introduction

There is growing interest in energy storage driven by new technologies and new drivers, particularly new highly scalable battery technologies with improving performance and falling costs. Much of this growing work focuses on the value propositions of distributed storage (Xi et al., 2014, Sue et al., 2014); however some technologies such as pumped hydro and compressed air are inherently large-scale, offering potential advantages when integrated into wholesale market operations. For large-scale utility applications, a key value proposition is that of energy arbitrage. There is considerable experience with this given decades of use of pumped hydro (Deane et al., 2010, Rehman et al., 2015); however electricity industry restructuring and growing renewable energy penetrations present a changing context for the value of utility-scale storage.

Wholesale energy arbitrage and ancillary services were highlighted by a recent consultant report as the primary non-network large-scale applications of energy storage, out of nine potential value streams in Australia, which include demand management and avoided network augmentation (AECOM, 2015). Energy arbitrage is currently considered low value given the high capital cost involved, in comparison to these other applications of energy storage (Sue et al., 2014, Denholm et al., 2013a), with large variations found in estimated revenue across NEM regions and years analysed (Hearps et al., 2014, Wang et al., 2014); however arbitrage can form an important component of revenue for energy storage operators that seek to provide multiple value streams with the same asset (Bradbury et al., 2014). Suitably aggregated distributed storage could of course also offer wholesale services of this type.

It should be noted that much of the existing Australian work is based on historical data, particularly pricing data. While historical analysis is valuable, it is not particularly useful for exploring the potential future role and value of energy storage in a changing electricity industry context. In the paper we present findings of a study aiming to assess the potential value of utility-scale energy storage arbitrage in a future low carbon NEM. This is done using a market modelling package that allows exploration of the value of storage under a range of possible future scenarios including different fuel prices, carbon prices and renewable energy penetrations. Similar market modelling of storage has been employed for US (Denholm et al., 2013b) and Irish electricity markets (Tuohy and O'Malley, 2011). The methods applied to our study are presented in Section 2 along with validation of the modelling tool. Modelling results for the value of energy arbitrage in future NEM scenarios are presented in Section 3, while Section 4 summarises these findings, and presents options for future work.

2. Methodology

A widely used PLEXOS market model of the NEM was adapted to determine market outcomes for short and medium term dispatch, suitable for exploring energy arbitrage. This NTNDP model includes data provided by AEMO which describes the current system. The model was first validated by running FY2014-2015, assessing price outcomes and using simple linear optimisation to optimise operation of storage for energy arbitrage. These results were compared with results using actual market prices over the year. Given validation, the same 2014 generation mix and transmission model were run for scenarios with varied fuel prices, carbon price and increased renewable energy penetrations. Linear optimisation was again performed to assess energy arbitrage value given resulting price outcomes.

2.1. National Transmission Network Development Plan

This study uses the 2014 NTNDP to characterise the future NEM. The NTNDP is a plan produced by AEMO annually to assist with the efficient development of the NEM transmission network over a 20-year planning horizon (AEMO, 2014a). The 2014 NTNDP publication includes a PLEXOS model developed to assist capacity expansion planning (AEMO, 2015a), which provides an accurate inventory of the NEM's baseline assets in FY2014-15. For each of the 5 regions (states), the NTNDP includes hourly regional demand traces (AEMO, 2014b), and data on all registered generators located on a common regional node, including fuel costs, O&M, heat rates and minimum stable levels. Marginal loss factors, minimum capacity factors, planned / unplanned outages and maintenance profiles are also taken into account. Only inter-regional transmission is modelled, with intra-regional congestion ignored. The regional demand traces are 10% POE (probability of exceedence) using FY2009-10 as a reference year. This year is representative of average outcomes for demand diversity and unscheduled wind energy output within subregions (AEMO, 2012).

The NTNDP PLEXOS model is designed to be used with the long-term (LT) Plan of PLEXOS, which optimises expansion planning over 10-30 year time horizons; however for this analysis, the model was repurposed to be used with the short-term (ST) Schedule, supported by the medium-term (MT) Schedule. The ST Schedule allows for an hourly chronological model of FY2014-15 to be simulated. In this model, both the dispatch periods and trading intervals are 1 hour, in contrast to the NEM's 5 minute dispatch / 30 minute trading interval operation. The MT Schedule accounts for optimisation over longer intervals by combining dispatch periods into 'blocks', allowing for competitor pricing behaviour and hydro storage targets to be modelled over the medium term (Energy Exemplar, 2015).

2.2. *Capacity Expansion PLEXOS Model*

The NTNDP capacity expansion PLEXOS model was adapted from its original purpose as an LT Plan least-cost model to one that could simulate realistic electricity prices for an hourly chronological year using the ST and MT Schedules. Competition was changed from short run marginal cost (SRMC), where generators only recover variable costs, to long run marginal cost (LRMC), where fixed costs are also recovered. Generators were each assigned to companies that reflected the current market (AEMO, 2015c), and could manipulate pricing bids strategically, with a limitation that quantities remain fixed. To simulate high pricing events, each generator had a mark-up bias towards peak periods implemented, with regional demand traces increased by 10%. Minimum up times were implemented for coal generators, and start-up costs were implemented for coal and gas generators (Kumar et al., 2012). A minimum synchronous generation requirement of 20% of a region's load was imposed for all dispatch periods to provide adequate system inertia, fault feed-in levels and system stability (Vithayasrichareon et al., 2015). Only coal, gas, liquid fuel and hydro generators were set to provide inertia, in contrast to non-synchronous photovoltaic (PV) solar and wind generators.

2.3. *MATLAB Analysis of Arbitrage Revenue*

The potential revenue of an energy storage operator performing energy arbitrage was modelled by exporting the PLEXOS FY2014-15 hourly pricing data for analysis with MATLAB (MathWorks, 2015). A linear optimisation program created by Jiefei Wang (Wang et al., 2014) was adapted to determine the total arbitrage revenue for the year. The linear optimisation was performed with the following assumptions:

- 1 MW / 1 MWh storage capacity (1 MWh selected after performing arbitrage revenue validation of PLEXOS model against 1-4 MWh).
- Storage is a price-taker (negligible effect on market price).
- Perfect foresight and optimisation over each 24h period (optimisation over an entire year was computationally infeasible).
- Ideal storage, with no self-discharge and 100% efficiency during charge/discharge.

2.4. *Modelling Validation*

Prior to simulation of the future NEM scenarios, validation of the PLEXOS pricing results was undertaken through comparison with actual FY2014-15 pricing data. This hourly data was extracted from AEMO's aggregated 30 minute price and demand data files (AEMO, 2015b). Figure 1 and Figure 2 compare the histograms of the actual FY2014-15 pricing data and the PLEXOS results. The results in each region were consistent with the actual pricing data, with the exception of Tasmania (TAS). Inspection of the PLEXOS TAS pricing behaviour yielded a significant disparity with the actual pricing results, and the TAS region was excluded from further analysis. Fewer price spikes occurred in the PLEXOS results, with only 24 >$1000/MWh periods compared to 52 periods in the actual pricing data.

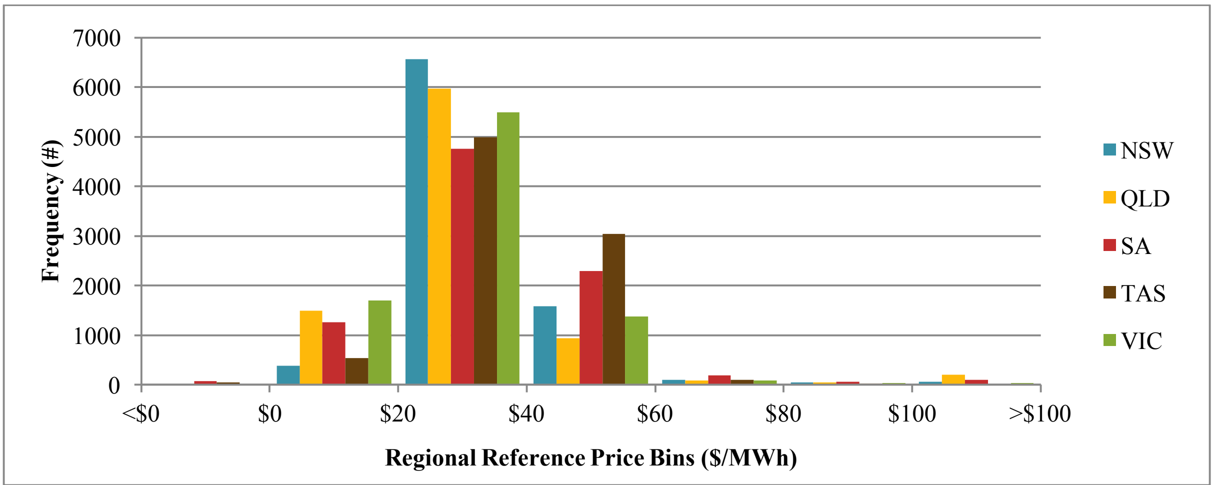

Figure 1. Histogram of actual FY2014-15 pricing results for 8760 1h dispatch periods

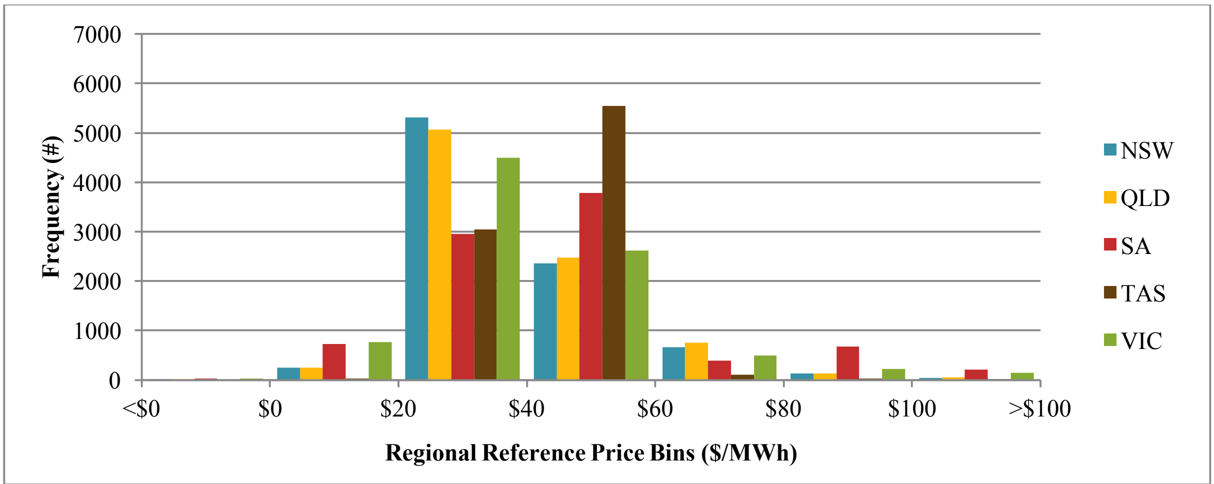

Figure 2. Histogram of PLEXOS FY2014-15 pricing results for 8760 1h dispatch periods

Figure 3 shows the potential arbitrage revenue available to a 1 MW / 1 MWh battery using the (i) actual pricing data and (ii) PLEXOS prices as inputs to the storage arbitrage model. The large disparity in arbitrage revenue for QLD can be attributed to the much higher frequency of price spikes observed in the actual pricing data. A special report from the Australian Energy Regulator (AER) found that congestion associated with transmission between Calvale-Wurdong and Calvale-Stanwell resulted in highly volatile prices in QLD during 2011 and 2012 (AER, 2012). Such price spikes are difficult to replicate in PLEXOS, as the model does not take into account intra-regional transmission (and associated congestion). Good agreement is obtained for NSW and SA using the PLEXOS and actual prices; however VIC revenue is notably higher using the PLEXOS prices, suggesting interference from inaccurately modelled high TAS prices through the Basslink interconnector.

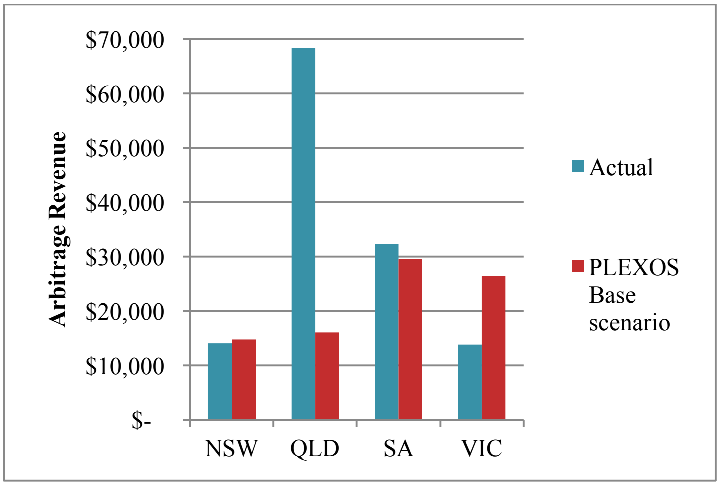

Figure 3. FY2014-15 arbitrage revenue for 1 MW / 1 MWh battery – comparison of actual pricing data and PLEXOS results

3. Results and Analysis for future scenarios

The impact of fuel prices, carbon pricing, and high renewable energy capacity penetrations on the potential value of wholesale energy storage arbitrage is explored in this section.

3.1. Effects of Fuel Price Changes

In order to assess the effect of fuel price changes on the value of wholesale energy arbitrage in the NEM, the prices of black coal and natural gas fuel were adjusted by ± 10% and ± 50%. The percentage change in arbitrage revenue from the PLEXOS Base scenario is shown in Figure 4, for each region and scenario.

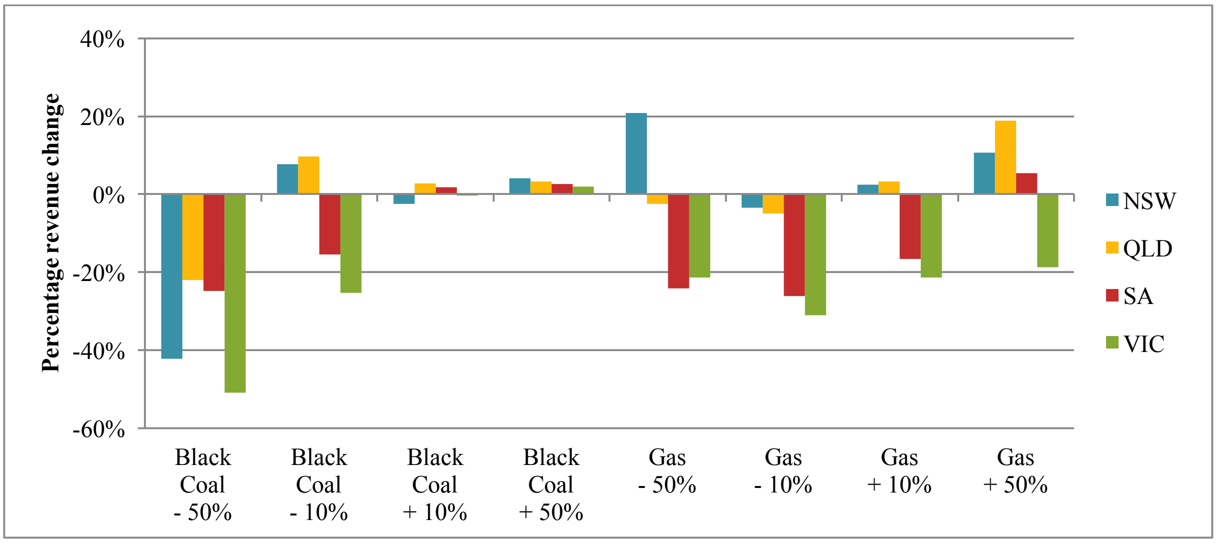

Figure 4. Percentage revenue change from Base scenario for a range of black coal and natural gas price changes

While increasing the price of black coal appeared to have minor (< 10%) effect on arbitrage revenues, decreasing the fuel price by 50% significantly reduced the potential arbitrage revenue, most notably in NSW (by 42%) and VIC (by 51%). This result can be attributed to a decrease in the difference in average SRMC between black coal generators in NSW and brown coal generators in VIC, as illustrated by Figure 5 and Figure 6. The net interconnector flow from NSW to VIC in this scenario increased 13% from 3911 GWh to 4497 GWh, supporting the hypothesis that NSW black coal was the marginal generator[1] in VIC (via the interconnector) a greater percentage of the time, implying a lower price difference and opportunity for arbitrage.

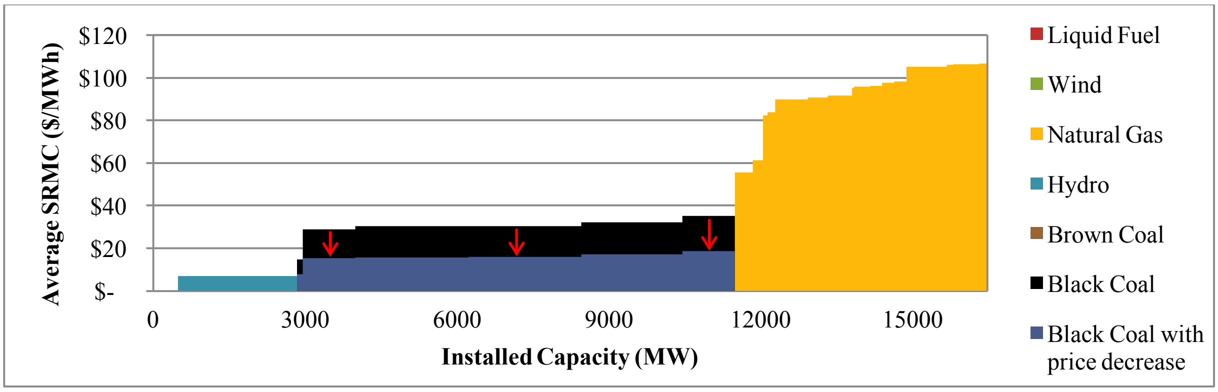

Figure 5. Average SRMC of NSW generation with 50% black coal price decrease

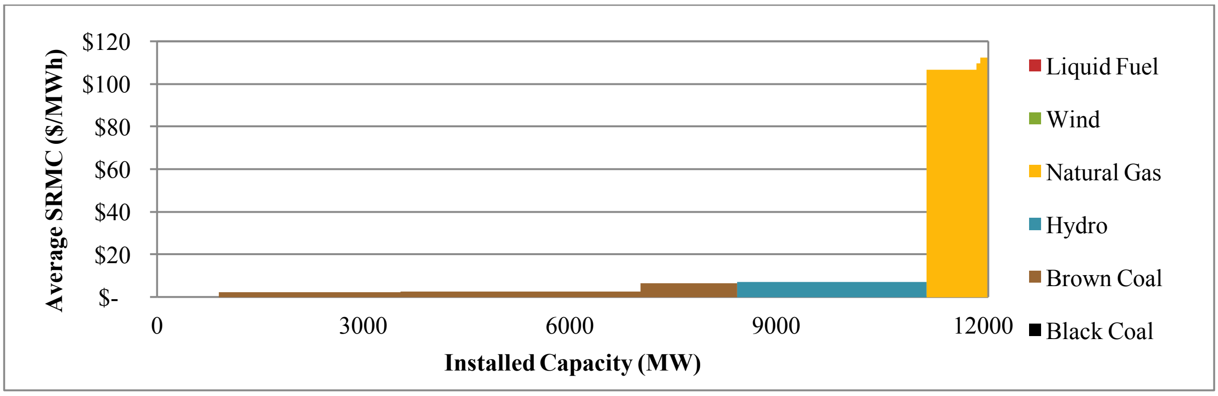

Figure 6. Average SRMC of VIC generation

A decrease in the price of natural gas generally resulted in lower arbitrage revenue, and can be attributed to the reduced difference in SRMC between gas and coal generation. Interestingly, a 10% increase in gas price also decreased arbitrage revenue in SA and VIC, with even a 50% increase resulting in lower arbitrage revenue in VIC. This unexpected result in VIC can be attributed to the negligible gas energy generation in that region (0.1%), highlighting that the revenue decrease was being caused by pricing in NSW, SA and TAS via the interconnectors.

3.2. Effects of Carbon Price Changes

Carbon prices ranging from $20/tCO_{2e}$ to $120/tCO_{2e}$ were implemented in the PLEXOS model to examine their effect on arbitrage revenues. Figure 7 demonstrates a general trend of increasing arbitrage revenue in all regions for an increasing carbon price above $60/tCO_{2e}$. This result can be explained by increased gas generation in those scenarios in SA and NSW. The decrease in revenue observed in SA for carbon prices $40/tCO_{2e}$ and below can be attributed to a reduction in the difference between SRMC of brown coal and gas generators in that region. The decrease observed in VIC could be due to the SRMC of VIC brown coal generators rising to approach the black coal price in NSW.

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[1] The marginal generator refers to the generator's bid which sets the regional price of electricity in a dispatch period (generators are dispatched in merit cost order).

Figure 7. Percentage revenue change from Base scenario for different carbon prices

3.3. *Effects of Renewable Energy Penetrations*

Multiple supply-side renewable energy capacity penetrations within each NEM region (except TAS) were implemented to explore the effect on arbitrage value. Only photovoltaic (PV) solar generation and wind generation were investigated, with 10-40% capacity penetration examined for each type. The impact of distributed PV generation, which affects the existing regional demand profiles, was not altered.

A range of hourly generation profiles sourced from AEMO (AEMO, 2014a) were used for new wind and PV generators to simulate geographic generation variability within each region (38 wind profiles and 27 PV profiles). Historical individual profiles for existing renewable energy generation (i.e. existing wind generators) were sourced from the NTNDP model. There was no existing large-scale solar generation in the 2014 NTNDP model.

To illustrate the potential value of utility scale energy storage arbitrage, Figure 8 shows a typical 3-day summer period of NSW energy generation and modelled arbitrage behaviour in the 40% PV/wind penetration scenario (as shown by an overlayed brown line referring to the right hand y-axis). The model indicates charging would occur at times of high PV generation, with a rapid discharge occurring during the afternoon when prices tend to peak. For example, during the afternoon of 11/02/2015, prices were high enough for natural gas to be dispatched, coinciding with the battery discharging to take advantage of increased prices. However, the increased wind generation the following afternoon resulted in reduced prices and therefore, a less aggressive discharge by the battery.

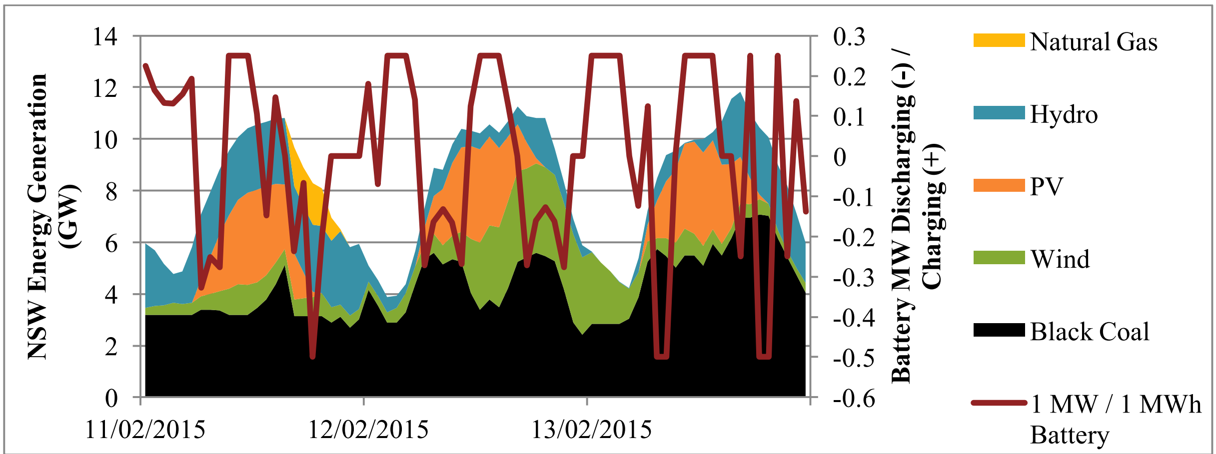

Figure 8. Typical 3-day summer period showing hourly generation in NSW, and the charge/discharge profile of a 1 MW / 1 MWh battery performing arbitrage – 40% PV/wind capacity penetration scenario

The effect of different PV and wind capacity penetrations on arbitrage revenue is shown in Figure 9. Increasing PV penetration resulted in significant increasing revenue for NSW and QLD, and a less significant increase in revenue for SA. -0.35, -0.34 and -0.23 correlations between periods of PV generation and prices in NSW, QLD and SA respectively were found in the 40% PV penetration scenario. These depressed prices during the middle of the day, due to highly correlated low-SRMC PV shifting the marginal generator, exaggerated the afternoon/evening peak in prices, and increased arbitrage opportunity. The standard deviation in prices for those regions increased 212% on average, supporting the arbitrage results.

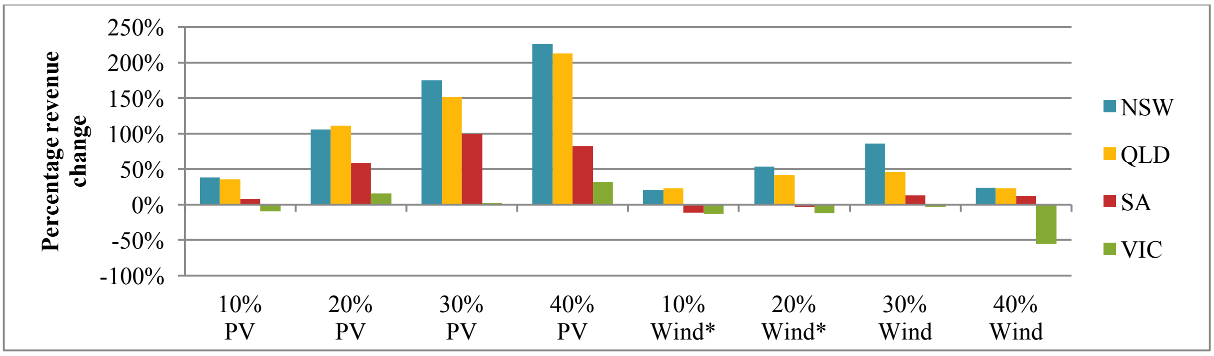

Figure 9. Percentage revenue change from Base scenario for PV and wind capacity penetration scenarios (*existing SA wind penetration kept at 29%)

Adjusting wind penetration had a less pronounced effect on arbitrage revenues, likely due to the less correlated wind generation profiles compared to PV. Generally, wind penetrations in all regions had increased or negligible effect on arbitrage revenue except in VIC for the 40% penetration scenario. In this scenario, prices were depressed during periods of high wind generation, consistent with the merit order effect of wind explored by (Forrest and MacGill, 2013). The frequency of $30-$40/MWh price periods decreased from 35% of all periods in the 30% wind penetration scenario to 10% of all periods in the 40% penetration scenario, explaining the reduced standard deviation of prices in VIC and associated arbitrage opportunity. Interestingly, the SRMC of NSW black coal averages $30-$35/MWh, suggesting that the increase in wind penetration from 30% to 40% shifted the typical marginal generator from NSW black coal to VIC brown coal. This explanation is supported by an increase in $0-$10/MWh periods from 41% to 70% of all periods, which is the SRMC of VIC brown coal.

Combined PV/wind penetrations were explored in the final set of scenarios, ranging from 10% PV/wind (5% each) to 40% PV/wind (20% each). The arbitrage revenue results are shown in Figure 10, designated by their combined renewable penetration.

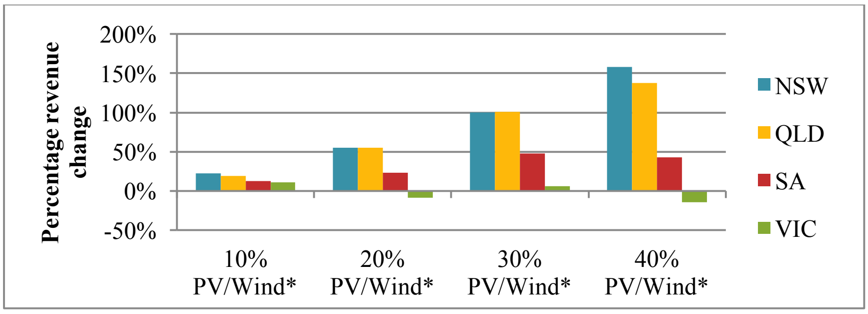

Figure 10. Percentage revenue change from Base scenario for PV/wind capacity penetration scenarios (*existing SA wind penetration kept at 29%, VIC penetration kept at 7% for 10% PV/wind scenario)

In NSW and QLD, the revenue increase reflects a cumulative increase of the PV and wind only revenue increases, with the underlying drivers assumed to be the same as explored previously. Evidently the chronological variability for wind tends to reinforce that of PV, not negate it, with 46% of the wind generation in NSW occurring during periods when PV did not generate at all.

4. Conclusions

This study has assessed the impact of fuel prices, carbon pricing, and high renewable energy capacity penetrations on the potential value of wholesale energy storage arbitrage using the NTNDP PLEXOS model. All three factors affected arbitrage revenue value to varying degrees. Analysis of the effects of fuel pricing revealed a distinct trend - decreasing the price of black coal reduced the difference between black coal and brown coal prices, and resulted in significant decreased arbitrage revenue. The implementation of a \$60/tCO_{2e} or greater carbon price resulted in increased arbitrage revenues proportional to the carbon price increase, as gas generators were dispatched more often, while lower carbon prices had variable effects depending on each region's generation fuel mix. Finally, renewable energy capacity penetrations of both PV and wind were also shown to affect the value of arbitrage.

Higher PV capacity penetrations up to 40% resulted in significant arbitrage revenue increases in the majority of cases, primarily due to exaggerating the afternoon/evening pricing peak. Higher wind capacity penetrations resulted in less pronounced, however still significant, revenue increases in NSW and QLD. Combined PV/wind penetrations generally resulted in significant arbitrage value increases in NSW, QLD and SA.

There are limitations with the market modelling undertaken for this study, in particular challenges with modelling the TAS region, and a lack of intra-regional constraints. The infrequency of price spikes in the model poses an additional challenge, as these could represent very significant revenue opportunities for storage. This study only considered the current generation mix in cases of fuel price and carbon price; however it can be envisaged that longer-term fuel and carbon price trends would change the mix in ways that might significantly impact findings. An investigation of arbitrage value with different future fuel mixes driven by high renewable energy penetrations / carbon prices as well as the impact of growing penetrations of both distributed and utility-scale storage would prove interesting. Energy storage arbitrage performed at scale could start to be a price-maker and cannibalise its own value.

Despite these limitations, the results suggest that such scenario modelling may be of use in predicting future impacts on the value of wholesale energy storage arbitrage, and provide valuable information for NEM participants and policy makers. Incorporating intra-regional transmission constraints and improving dispatch resolution to 5 minute periods would provide more realistic pricing results and arbitrage revenues. Future studies could consider an integrated analysis of both revenue value and cost of energy storage to better understand the utility-scale storage investment proposition.

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