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Estimating the value of electricity storage in an energy-only wholesale market

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HIGHLIGHTS

- Storage devices effectively provide a similar service to peak generators.
- The capacity value of storage was found to be insensitive to the round trip efficiency.
- Storage devices may compete with traditional peak generation technologies.
- The ability to derive additional revenue from energy arbitrage provides a competitive advantage to storage devices.

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ABSTRACT

Price volatility and increasing renewable energy generation have raised interest in the potential opportunities for storage technologies in energy-only electricity markets. In this paper we explore the value of a price-taking storage device in such a market, the National Electricity Market (NEM) in Australia. Our analysis suggests that under optimal operation, there is little value in having more than six hours of storage in this market. However, an inability to perfectly forecast wholesale prices, particularly extreme price spikes, may warrant some additional storage. We found that storage devices effectively provide a similar service to peak generators and are similarly dependent on and exposed to extreme price events, with revenue for a merchant generator highly skewed to a few days of the year. As a consequence of this finding, and in contrast to previous studies, the value of storage was found to be relatively insensitive to the round trip efficiency. We also found that the variability of revenue and exposure to extreme prices could be reduced using common hedging strategies, such as those currently used by peak generators. We present a case study that demonstrates storage technologies using such strategies may have a competitive advantage over other peaking generators in the NEM, due to the ability to earn revenue outside of extreme peak events. Similar to traditional peak generators, a main driver for storage options in an energy-only electricity market is extreme prices, which in turn is dependent on capacity requirements. However storage technologies can receive additional revenue streams, which may be improved by increased integration of renewable energy.

1. Introduction

Volatile prices are a common feature of competitive wholesale electricity markets, and especially energy-only markets [1]. While market structures vary considerably from country to country, electricity prices in energy-only markets invariably demonstrate significant short term variation. This is a function of the underlying characteristics of electricity supply: consumption and production must instantaneously match – a novel feature for a commodity market [2].

Electricity has generally been considered a non-storable commodity [3]. The lack of options to cost-effectively store electrical energy on a significant scale means that electricity systems are sized to meet the maximum potential peak demand, and electricity markets rely on the real-time balance of supply and demand.

A common feature of electricity markets with limited or no storage is price volatility with extreme price spikes. Rapid variations in demand over short periods, outages of generators or transmission lines, and generator bidding behaviour result in highly volatile prices [4]. Historically, flexible generators such as Open

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Cycle Gas Turbines (OCGT) have been used to provide peak capacity and respond to these rapid changes in demand and price. Due to its high flexibility, gas is also often considered to be an ideal partner for variable renewable generation [5].

Electricity storage technologies can also provide peak demand capacity in addition to grid reliability and assist the integration of renewable energy sources [6]. Large-scale electricity storage offers an alternative to gas for power system balancing, as variable renewable generation continues to expand [7]. In Australia the market operator (AEMO) recently undertook a study exploring an Australian market powered entirely by renewable energy [8]. This study found that significant energy storage was crucial to such a system in minimising cost while maintaining reliability and security standards.

In this paper we analyse the current value of electricity storage deployed in Australia's National Electricity Market (NEM), recognised as one of the better designed and implemented energy-only markets [9,10]. Unlike many studies, this work includes both an evaluation of the value of time shifting energy, capitalising on arbitrage opportunities *and* the value of providing peak capacity, with a case study comparison to OCGT's. We focus on the South Australian (SA) market region which has one of the highest penetrations of wind power in the world, with 31% of the electricity generated coming from wind in the 2013–14 financial year [11]. As such, this study provides interesting and useful insight into the energy and capacity value of storage in an energy-only electricity market in a system with high renewable energy penetrations.

1.1. Literature review

Energy storage technologies have historically been uneconomic to install and operate, with the exception of pumped hydro. Increasing penetrations of variable renewable energy technologies, such as wind and solar, have renewed interest in evaluating the arbitrage opportunities [12,13].

There are now many studies that investigate the economic viability of electricity storage in electricity markets around the world. This analysis is predominantly limited to assessing the arbitrage value only, capturing the price differential resulting from electricity market volatility.[1]

Typically the economic viability of storage has been evaluated with a price-taker model, using historical market prices [14], sometimes referred to as a 'small device' energy arbitrage model. For example, in the U.S., Sioshansi et al. [15] analysed the PJM interconnection, Walawalkar et al. [16] analysed the NYISO interconnection and Bradbury et al. [12] analysed the value of storage in seven U.S. wholesale markets. These approaches do not consider non-arbitrage value, but both Bradbury et al. [12] and Sioshansi et al. [15] recognised that energy storage may have additional value in the ancillary services and capacity markets.

Internationally, Figueiredo et al. [17] investigated and compared the economics of 14 power markets. Graves et al. [18] looked at the arbitrage opportunities of storage in the U.S., and compared these to international markets. Connolly et al. [19] compared optimal arbitrage profits across 13 electricity spot markets. These papers also papers consider different operational strategies to evaluate 'real-world' arbitrage opportunities, incorporating the uncertainty of future electricity prices.

Increasingly, attempts have been made to model the dispatch of storage devices by co-optimising energy arbitrage with provision of energy reserves. Drury et al. [20] quantified the additional value of reserves for a Compressed Air Energy System (CAES) in several markets. More recently, Das et al. [14] analysed the co-optimised value of storage in both the energy market *and* the ancillary service market, using a market modelling approach. This paper utilised a storage dispatch model based on arbitrage opportunities across energy and ancillary service markets ("cross-arbitrage"), with the simulation results applied to a Compressed Air Energy Storage (CAES) system.

While the Das et al. [14] paper co-optimises across the different services, the economic dispatch formulation uses both a *Unit Commitment* (UC) and *Economic Dispatch* (ED) program. The UC is run a day-ahead and the ED is run once the commitments decisions have been made. At the same time, the capacity is considered separate to the energy market (as a regulation service), with bid price parameters capped at \$350/MW. Drury et al. [20] also used reserve price data, separate from the energy market data, to optimally dispatch the storage devise.

In this paper, we extend the literature by investigating both the arbitrage value and capacity value of storage in an energy-only market with a high penetration of renewable energy. Unlike the Das et al. [14] work we use historic market data in an energy only-only market, with a single market for both energy and capacity. However we also explore the capacity value separate to the arbitrage value, which is often missing from historic price-taker analysis.

This paper is organised as follows: Firstly, we describe some of the key characteristics of the NEM. Then we characterise the basic relationship between storage capacity and the arbitrage value of energy storage, using a small-device energy arbitrage approach, assuming optimal operating regime and *'perfect foresight'* of electricity price. Thirdly, we determine the value using wholesale price forecasts in order to assess the impact of the uncertainty of future electricity prices and estimate the accuracy of perfect foresight analysis. Finally we analyse how hedging strategies typically used in the supply of *capacity* to the market might effect the value. We finish with a discussion of the implications of the analysis and how the value may evolve over time.

1.2. The Australian electricity market

The Australian National Electricity Market (NEM) is a gross pool, energy-only market along the Eastern seaboard of Australia, supplying electricity to approximately 90% of the Australian population. It is often held up as a exemplar of an energy-only market [10], with a price cap explicitly based on the Value of Lost Load (VOLL). The price cap is currently one of the highest in the world at \$13,100/MWh, about 300 times the volume weighted price average of around \$45 [9].[2] The market has a floor price of −\$1000/MWh. Historically, prices have often reached the price cap during periods of scarcity, and the market has been noted as one of the most volatile commodity markets in the world [21].

The NEM consists of five interconnected regions, with the dispatch process centrally managed by the market operator AEMO. Wholesale Regional Reference Prices (RRP) are calculated for each region and set the settlement price for all generators in the region. All transaction is the NEM are settled against a half-hourly spot price. However, dispatch within the NEM is optimised by the operator on 5 min intervals, and as such is considered a 'fast market'. Fast markets (with short dispatch intervals) provide incentives for dispatchable, flexible capacity rather which would otherwise be met by regulation reserves [22]. This is reflected in the relative small size of the Frequency Control Ancillary Services (FCAS) market relative to wholesale spot market. In 2014, payments through

[1] Buying power when power prices are low, and reselling it at a higher price, hours or days later.

[2] The price cap changed over the period analysed increasing from \$10,000, to \$12,500 in 2010, to \$12,900 in 2012 and then to \$13,100 in 2013.

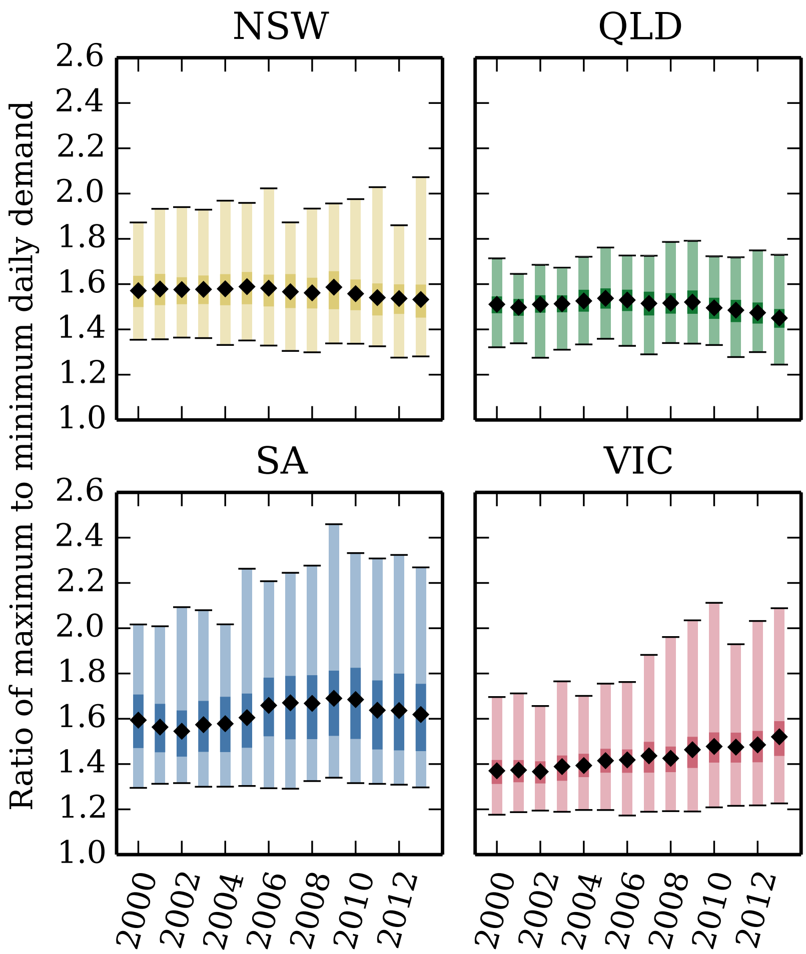

Fig. 1. Boxplots illustrating the annual spread of daily demand variation, (calculated as a ratio of the maximum daily demand over the minimum daily demand), for the four main NEM regions.

the FCAS market (regulation and contingency) totalled $30 million, while payments through the spot market totalled $10.8 billion.

The electricity demand profile and characteristics vary across each region as illustrated in Fig. 1, reflecting both economic and climatic factors. The relative daily variation in demand is the highest in the South Australian Market region. For example, on the 30th of December in the summer of 2009 in South Australia, the peak demand (2657 MW) was some 2.5 times greater than the overnight minimum demand (1080 MW). Over the 2010–11 summer in South Australia, the daily peak demand varied between 1500 MW and 3400 MW [23].

Network constraints between the regions, in combination with the regional differences in load and generation capacities, translate into differences in both regional prices and price volatility. Fig. 2 presents a measure of volatility (standard deviation of $\log_{10}$ of the regional price) of the four major regions over time. Prior to 2007, volatility across all regions was relatively stable at around 0.22 and closely correlated. A significant increase in volatility from late 2007 through 2008 reflected the intense drought conditions across the eastern seaboard of Australia that effectively constrained both hydro and thermal generation in a number regions. Since 2009, there has been a notable downward trend in volatility, with an increasing separation in the volatility between the regions.

Until 2008, demand on the NEM was growing at about 2% each year. Since 2008 there has been a reduction in demand for electricity on the NEM with the decline averaging about 1.5% per year. The reduction in demand, combined with a return to average rainfall conditions, has lead to increasing overhang in generation capacity on the NEM, and consequent general reduction in volatility. The system peak for last financial year was approximately 33 GW and the total registered capacity is approximately 52 GW, suggesting a capacity overhang of 37%.

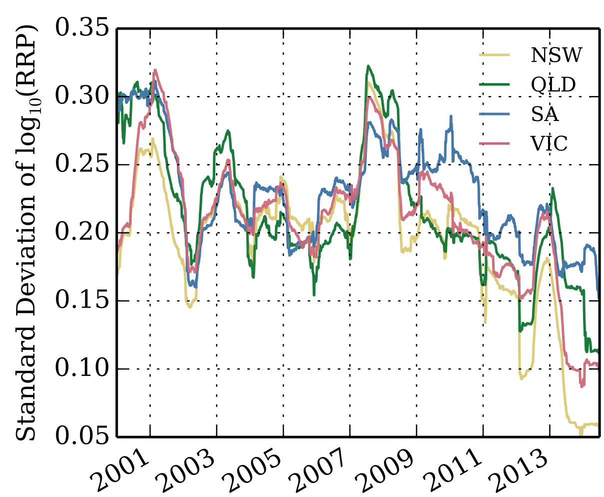

Fig. 2. Rolling standard deviation of $\log_{10}$ of the regional price for the four main regions.

The trend in South Australia's volatility has increasingly diverged from the other regions on the NEM since 2008, having persistently recorded the highest volatility. This most plausibly relates to the increasing penetration of wind and solar generation in South Australia over this period. Since 2007, over 800 MW of wind capacity has been commissioned in South Australia, bringing the total wind capacity in the region to 1203 MW [24]. Rapid deployment of photovoltaic solar in recent years has also seen the installation of an estimated 540 MW of rooftop solar systems to August 2014 [25]. Together, this represents a significant penetration of renewable energy, in a region with a mean demand of about 1460 MW[3], and a system peak of 3385 MW (in 2011). The remaining generation capacity is dominated by gas (2672 MW) and brown coal (770 MW). The annual electrical energy consumption in 2013 was 13,330 GWh [24].

Given these characteristics, the South Australian market region provides a pertinent example to explore and illustrate the potential value of storage in an energy-only market.

2. Assumptions and methods

In the analysis below we assume a small-device energy arbitrage model to analyse the viability of energy storage. This technique assesses the revenues storage can generate via the purchase of low-cost electricity and sale of high-cost peak electricity in an electricity market assuming the device is sufficiently small that it doesn't effect prices, that is, it is a price taker. Future electricity prices are also assumed to be known ahead of time (perfect foresight), and hence perfect optimisation of the operation of the storage device is possible. The FCAS market is very small relative to the wholesale market due to the fast nature of the NEM, (see Introduction). As such, we do not explicitly co-optimise with the ancillary market as it is not expected to have a measurable impact on the results. The analysis is device agnostic, applicable to any storage device technology.

We use the COIN-OR Linear Program [26] solver to find the optimal dispatch, that maximises the arbitrage profit for a hypothetical merchant[4] storage facility in the South Australian Market region for a range of storage capacity scenarios from 0.5 to 10 h storage. The power capacity is effectively dimensionless: under the small device assumptions optimal operation of a 1 kW unit with 5 h storage would be the same as a 20 MW facility with 5 h of storage.

In our analysis, the optimisation problem was constrained by the rated power capacity of the storage device, for both charging and discharging (unity in this case), and the hours of storage (h). We assume that the storage device has the same input and output power capacity, and round trip efficiency of 75% for the base case (i.e., 10 h of charging is required for 7.5 h of discharge generation). We explore sensitivity to round trip efficiency, as discussed in Section 6.

All wholesale transactions in the NEM are settled against the half-hourly spot price. The operation of the device was therefore optimised against this price. Two optimisations were conducted for each scenario, one using day-ahead prices only, and another using a full year ahead of price data. The two different optimisation horizons allow intra-day and inter-day arbitrage opportunities to be compared, and to understand the importance of electrical price forecasting for storage.

The optimisation problem is formulated as follows:

$$\text{maximise} \sum_{t=1}^{t_{max}} (rrp_t \times d_t - rrp_t \times c_t)$$

Subject to the constraints:

$$s_t = s_{t-1} + \eta \times (c_t - d_t)$$
$$0 \leqslant s_t \leqslant s_{max}$$
$$c_t, d_t \leqslant 1 (\text{unity power capacity})$$

where

rrp_t = regional reference price at time t
d_t = discharging rate at time t
c_t = charging rate at time t
t_{max} = optimisation time horizon
s_t = storage level at time t
s_{max} = maximum storage level
η = round trip efficiency

In the first instance, storage device operation was optimised assuming perfect knowledge of the wholesale prices, whilst ensuring these power capacity and storage capacity limits were not violated. In a second iteration wholesale price forecasts from the system operator were used to capture the real world uncertainty of future electricity prices.

3. Relationship between storage configuration and value

Fig. 3 shows the half hourly energy prices during a sample period (a week in January, 2012 in South Australia) and the corresponding optimal dispatch and storage levels over that period. As expected, the optimal dispatch follows the prices, with energy stored during low price periods and generated during high price periods. Fig. 4 illustrates the average optimal operating regime, for different hours of the day and different days of the year in South Australia. As expected, the dispatch follows the seasonal price and demand patterns characterised by a bi-modal peak in winter and an afternoon peak in summer.

Fig. 5 shows the value of a storage device ($/kW-yr) for different storage capacities (hours) over different financial years. This value represents the revenue that could be expected per year, per kW of generation capacity installed for a fully merchant operator under optimal operation. The graph illustrates considerable variation in the estimated annual revenues. The variation in the annual

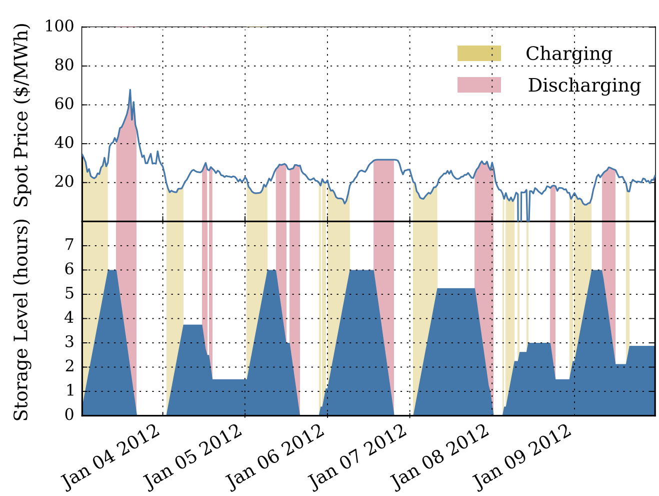

Fig. 3. Optimal operation of storage device, a week in January, 2012 in South Australia.

[3] South Australian demand has been declining since 2011, in part as result of increased solar generation 'behind the meter'.
[4] Uncontracted power plant, entirely reliant on spot market outcomes.

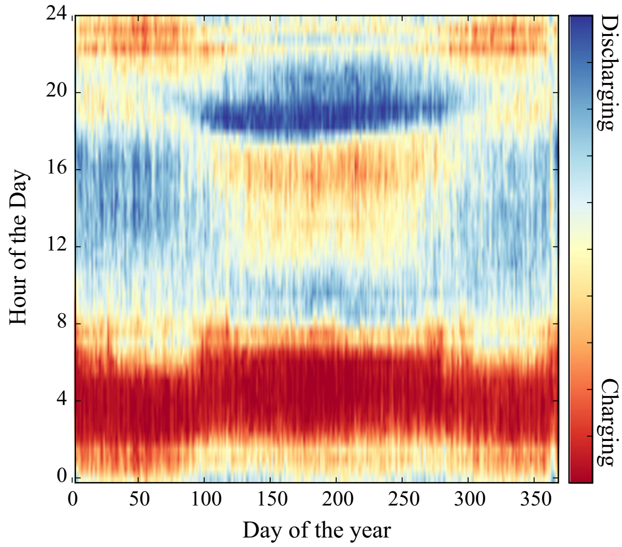

Fig. 4. Optimal operation characteristics, for winter and summer months of the year. Plots show number of days that a device is charging or discharging at different hours of the day.

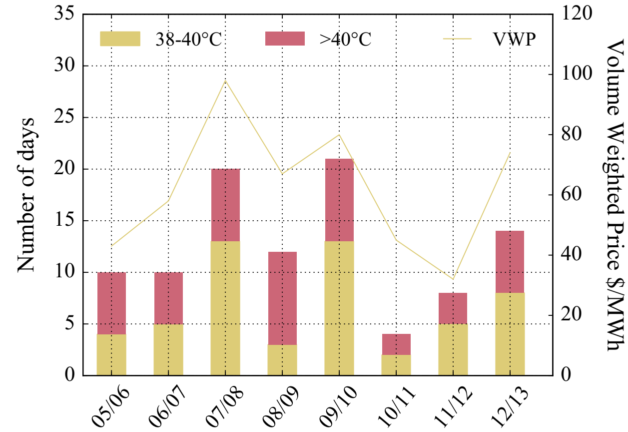

Fig. 6. The volume-weighted electricity prices follow a very similar pattern to the number of days in South Australia reaching 38 °C or higher.

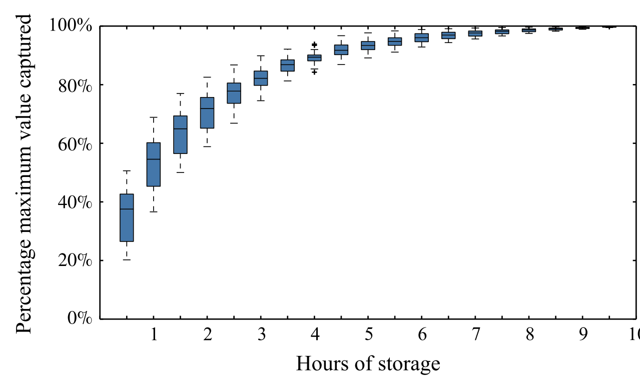

Fig. 7. Normalised value of storage, as a function of hours of storage (the value of storage as a percentage of the maximum value possible for a given financial year). Box plots represent the distribution of values captured over all financial years modelled.

arbitrage value mirrors the trends in wholesale price volatility in Fig. 2 as well as the number of days where ambient temperature ⩾38 °C in Adelaide (see Fig. 6). As with many energy markets this reflects the impact that weather, and in particular temperature has on price and demand. The correlation between the number of extreme weather days and annual arbitrage value reflects this relation ship and the finding that merchant arbitrage revenue is generated on only a few days of the year. This will be discussed further below.

Fig. 7 provides additional insight, illustrating the basic relationship between storage capacity and the arbitrage value. The plot shows the 'normalised' value of storage, the value of storage as a percentage of the maximum value possible for a given financial year. As illustrated, almost 90% of the total potential value is recovered with only four hours of storage. Beyond six hours of storage, there is limited marginal value in extending the amount of storage with the additional storage providing only limited incremental arbitrage opportunities. This relationship is displayed in the other market regions, and is consistent with the PJM analysis, which demonstrated that 50% of the value in the PJM market was recovered with the first four hours of storage, and eight hours of storage captured 85% of the total potential storage [15].

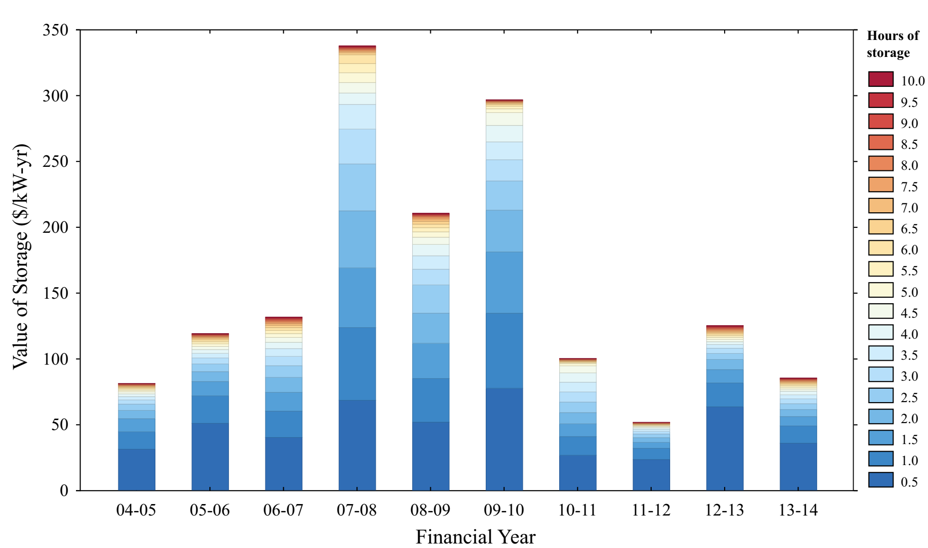

Fig. 5. Value of storage by financial year and storage capacity, for South Australia.

The optimisation time horizon has limited impact on the distribution and magnitude of the values illustrated in Figs. 5 and 7. This indicates there is limited value in inter-day arbitrage opportunities, or indeed beyond six hours of storage. However, the marginal cost of the next incremental hour of storage can vary widely by technology (or geography in the case of pumped hydro) which can affect the optimal configuration. For technologies with low installed capacity cost ($/kW) relative to energy storage costs ($/kWh), systems with a small amount of storage (in hours) may be more economically viable. A technology with relatively high installed capacity costs may opt for a larger amount of storage (in hours). The interaction between arbitrage opportunity and technology cost structure is beyond the scope of this paper.

These representations fail to highlight key characteristics of the revenue gained. As mentioned, the NEM has a high market cap price (relative to the average price and marginal cost). As such, the profit generated by a hypothetical merchant storage facility is highly skewed to a few hours of the year. Fig. 8 shows that across the years analysed for South Australia, practically all of the arbitrage profit is generated on a small number of days (where the price hits the market price cap). Thus, the hypothetical profit is highly contingent on being dispatched in these high-value periods. The extent to which this is possible will depend on location-based factors, such as network constraints, and whether the device is sufficiently charged to fully capture the value of high prices. Due to uncertainty of electricity prices, and the inability to accurately predict peak prices, the ability to maximise benefit is at some risk, depending on the specific charging strategy applied to the device.

The extent that recovering revenue depends on high price events can be further illustrated by comparing the median charging and discharging prices, with the volume weighted charging and discharging prices. As shown in Table 1, the difference between the median prices is quite small (relative to the difference between the volume weighted prices) implying total annual revenues are sensitive to the number of extreme price events. This is particularly evident in the drought years from 2008 through 2010.

Sensitivities of optimisation to round trip efficiency were also explored. Interestingly, the value of merchant arbitrage is not particularly sensitive to the round trip efficiency. This result is related to the revenue profile, (illustrated in Fig. 8), and the fact that much of the revenue is made in trading intervals that approach the market price cap (which is over 200 times the average price).

To illustrate this point, consider a case where average charging prices are $50 per MWh, with the energy later sold at the market cap price. In this case, it makes little difference if the device has a round trip efficiency of 50% and two MWh's are bought to sell one later at $13,100/MWh, or 100% round trip efficiency, where only one MWh is bought to be later sold. The return per MWh generated differs by only 0.4%. This is analogous to OCGT, which may only run during these same peak periods for a fraction of the year, and is therefore not particularly sensitive to the fuel prices (gas).

Table 1
Comparison of volume weighted prices (VWP) and median prices for charging (subscript c) and discharging (subscript d) under optimal operation in SA since 2012. Difference between discharging and charging prices shown in bold (for both VWP and median price).

Year	VWP_d	VWP_c	*ΔVWP*	$Median_d$	$Median_c$	*ΔMedian*
2002	$70.93	$18.55	**$52.38**	$40.28	$17.57	**$22.71**
2003	$46.95	$15.09	**$31.86**	$30.18	$14.70	**$15.49**
2004	$89.98	$21.47	**$68.51**	$43.67	$19.66	**$24.01**
2005	$65.22	$18.60	**$46.62**	$38.72	$17.62	**$21.10**
2006	$81.37	$19.91	**$61.45**	$42.48	$18.33	**$24.16**
2007	$103.40	$32.45	**$70.94**	$66.86	$28.61	**$38.26**
2008	$189.13	$22.06	**$167.07**	$48.85	$21.72	**$27.13**
2009	$179.39	$17.52	**$161.88**	$38.54	$18.52	**$20.02**
2010	$124.30	$13.62	**$110.68**	$33.74	$17.75	**$15.99**
2011	$85.00	$17.28	**$67.71**	$37.94	$20.20	**$17.74**
2012	$69.34	$21.93	**$47.41**	$45.53	$23.42	**$22.11**
2013	$163.33	$47.77	**$115.56**	$81.40	$45.93	**$35.47**

4. Impact of forecasting on arbitrage value

One of the limitations of this basic arbitrage analysis is the perfect foresight assumption for energy prices. There is substantial uncertainty around short-term future electricity prices, particularly in the case of scarcity events and extreme price spikes in an energy-only market. Consequently, perfect foresight is an unrealistic idealisation. In reality the scheduling an energy only market necessarily entails some uncertainty of future prices. In this section, we compare the value of the optimal dispatch assuming perfect foresight with a more realistic scenario to evaluate the accuracy and suitability of using the perfect foresight assumption.

A variety of approaches have been proposed for incorporating imperfect foresight in electricity markets. Connolly et al. [19] compares a *'historical strategy'* and a *'prognostic strategy'* with an optimal strategy and Sioshansi et al. [15], uses a *'back casting'* approach, based on historic prices for the previous two weeks. In this analysis, we use pre-dispatch prices from the AEMO. As these price projections are generated approximately a day ahead of time, the approach is comparable to the prognostic strategy of Connolly et al. [19].

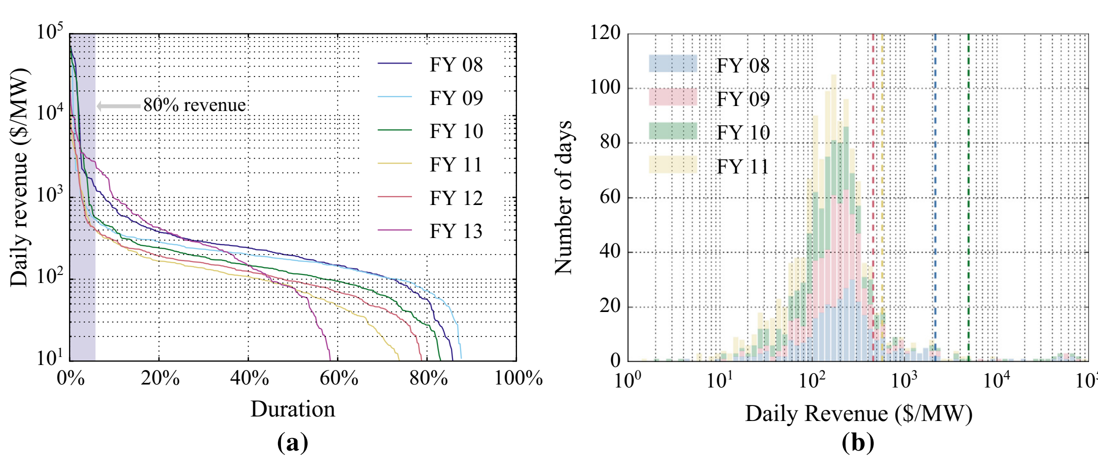

Fig. 8. Left panel: revenue duration curves for financial years 2009–10 through 2013–14 for South Australia. Right panel: histogram of daily revenue over four financial years. Vertical lines illustrate the price above which 80% of revenue is generated for each financial year.

In this optimisation, the forecast pre-dispatch prices, which are generated by the market operator each half hour, are used to determine the optimal operation within that current half hour period. This rolling window approach is necessary due to the variable nature of the pre-dispatch prices, and because the pre-dispatch forecast becomes more accurate as the dispatch period approaches. Fig. 9 illustrates how the pre-dispatch forecast accuracy improves as the forecast trading interval approaches.

Fig. 10 compares the potential value of storage using pre-dispatch prices and perfect foresight for FY 2012–13. With six hours of storage, the strategy using pre-dispatch prices captures 85% of the potential value with perfect foresight. Sioshansi et al. [15] found a similar accuracy using the back casting approach, and Connolly et al. [19] found their prognostic strategy achieved 81% of the optimal strategy profits.

As shown in Fig. 10, increasing the storage improves the realisation of potential arbitrage value, from 70% at 3 h to over 90% at 8 h. This may be due to increased flexibility of the storage device. The ability to re-evaluate and change operation may be constrained for smaller devices. This analysis suggests that the additional value in storage beyond the six hours, increases with the uncertainty in pre-dispatch price projections.

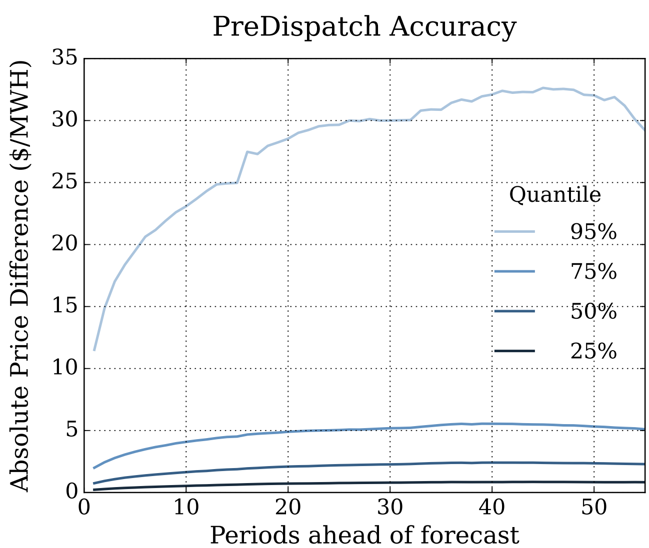

Fig. 9. Pre-dispatch forecast accuracy. This figure presents the distribution of forecast errors against the number of trading intervals ahead of time that the forecast is made.

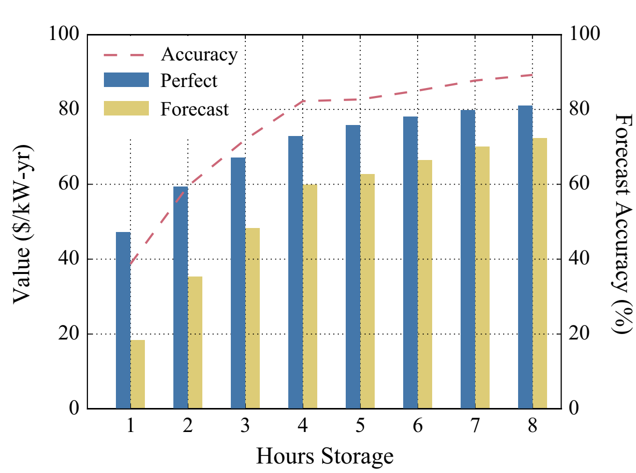

Fig. 10. Forecast vs perfect foresight for FY 2013–14. Value comparison ($/kW-yr, left hand axis) and accuracy (%, right hand axis).

While the perfect foresight assumption necessarily provides an upper limit to arbitrage opportunities, our analysis shows that it only overestimates the values realised in a market such as the NEM by around 10–20%. More sophisticated analysis of pre-dispatch pricing (and the frequency and likelihood of price spikes that are not forecast) would further improve the value captured using pre-dispatch prices than the simple approach used here.

5. Capacity value of storage

Actors participating in volatile markets such as energy-only markets face high financial risk. As such, a variety of hedging and risk management strategies are used by market participants to manage their exposure to the wholesale market. For electricity markets hedging strategies fall into three broad categories: bi-lateral Over-The-Counter (OTC) contracting, Exchange Traded Futures (ETF) and Vertical Integration, where a retailer, that would otherwise be the OTC counter-party, is owned by a generator, [27].

In the NEM it is highly unlikely that any new generation facility would be constructed on a fully merchant basis: the price and volume risks are too great. Typically, a project developer will enter into a long term Power Purchase Agreement (PPA) with an off-taker (such as a retailer or large energy user), or manage risk internally via vertical integration.

Different types of generators will make use of different types of hedging products. Power purchase agreements for bulk energy generation are typically structured as a swap contract (sometimes called a contract for differences). A more relevant product for generators supplying peak capacity are cap contracts, which are a derivative product similar to an option [4]. Currently, any new OCGT capacity would be financed through the sale of cap contracts, (and conversely, OCGT's are a major sellor of cap contracts[5]). Given that storage provides similar flexibility and capacity to OCGTs, is similarly dependent on and exposed to extreme price events (see Fig. 8), and would likely be financed in a similar way, cap contracts are explored here in more detail.

A cap contract is a derivative product that effectively places a cap on the price that a customer (for example a retailer) pays for electricity. A cap contract at $300 per MWh (the usual cap contract traded in Australia) ensures that the contract buyer will effectively pay no more than $300 per MWh for the contract volume, regardless of how high the price rises (for example market price cap of $13,100) [28]. The seller of the contract compensates the customers when spot prices are above $300, and in return receives a consistent payment. Generators that sell contracts effectively receive no more than $300 per MWh (since they are compensating the retailer for prices above this level), however they might also receive a consistent payment (e.g. $10/MWh) for every trading interval of the year regardless of whether they are dispatched or not. Peak generators and storage technologies are well suited to selling cap contracts as they reduce risks around the uncertainty of the occurrence of price spikes. Fig. 11 shows the current and historic cap prices for the different market regions for 1st quarter for 2015 (mainly summer months in Australia).

To analyse the affect of the expected hedging contracting and hedging strategies, we modelled the value of storage, assuming it sold cap contracts at $300 per MWh. For prices at and above $300, the storage device received $300, and for prices below $300, the storage receives the market spot price. A penalty of the spot price minus $300 is assumed for any periods where the price is above $300 but the storage device is not discharged (e.g. storage

[5] Legacy hydro-generators are also significant providers of cap contracts in Australia.

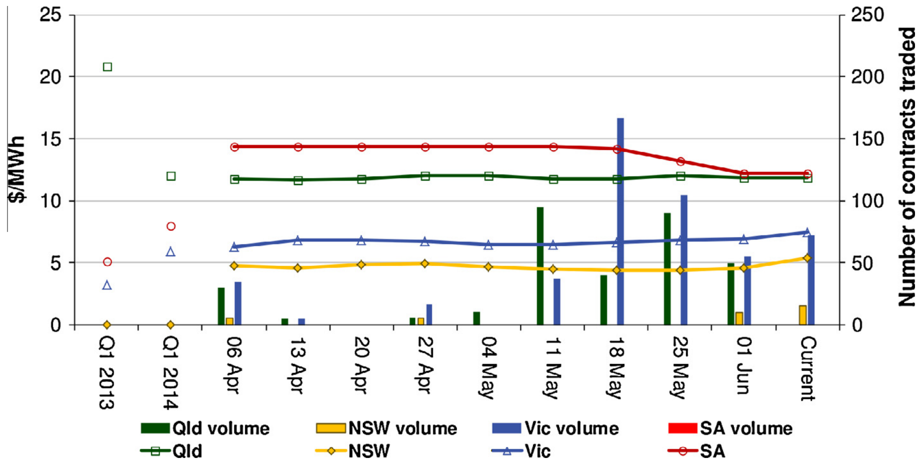

Fig. 11. Price of Q1 2015 cap contracts over the past 10 weeks (and the past 2 years). *Source:* AER Market Snapshot, August 2014.

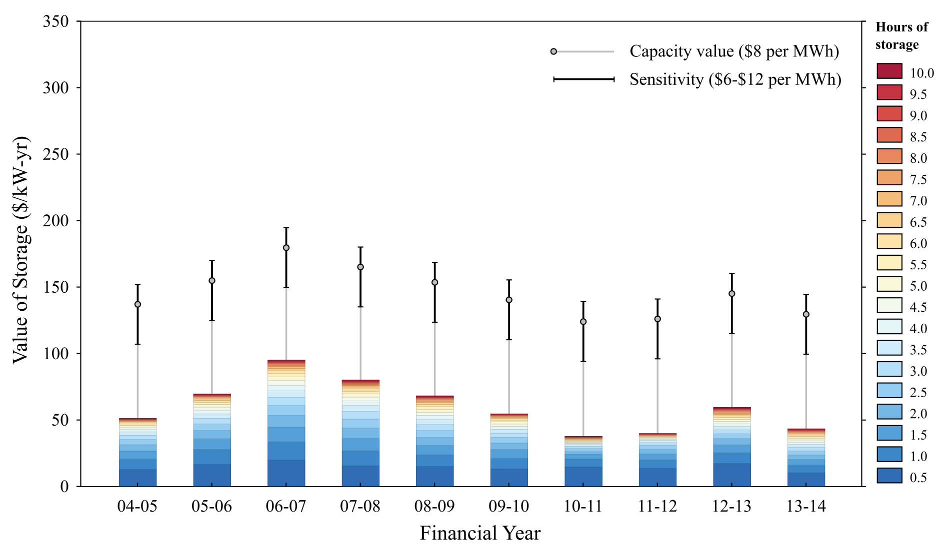

Fig. 12. Value of contracted storage plant by financial year and storage capacity, for South Australia.

is empty), as would occur in the case of an unplanned outage at a fossil fuel peak generator.

Fig. 12 illustrates the value of storage under these conditions. A cap price value (between $6-$12 / MWh) was added to the arbitrage value to illustrate the potential total value. Compared with Fig. 5, the annual revenue profile is considerably more consistent.

5.1. Case study – pumped hydro vs OCGT

In this section we compare the *cost of capacity* of a storage device with an OCGT generator. Rather than estimating the value of storage using different assumptions of cap contract value, we consider what contract price would be needed to finance a particular storage plant. This is compared to an OCGT, using a levelised cost of capacity (LCOC) metric.

Many studies have compared the LCOC of various energy storage technologies [19,29,30]. As these studies indicate that Pumped Hydro Electric Storage (PHES) is both the most mature and cheapest large-scale energy storage technology currently available, we chose to consider PHES as the storage device in this case study. We used PHES technology costs and assumptions from the Electric Power Research Institute [30,29] in the LCOC calculation, and Bureau of Resources and Energy Economics [31] for OCGT costs. More details of the calculation can be found in the supplementary material.

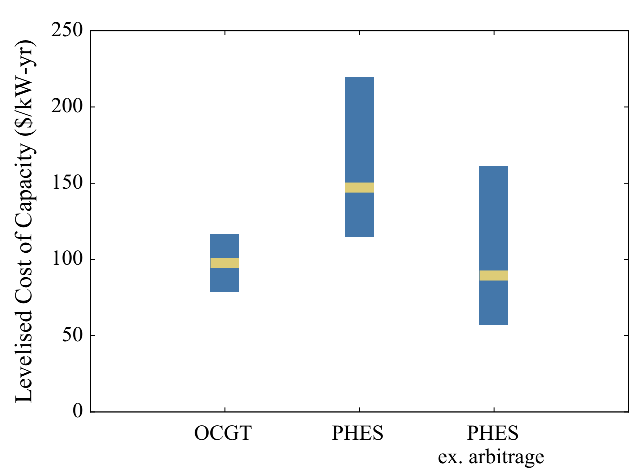

Fig. 13. Levelised cost of capacity for an OCGT, a PHES and a PHES after taking into account the sub $300 arbitrage value.

Two different LCOC's were calculated for the PHES device. One calculated the total LCOC, irrespective of the value of arbitrage (below $300). The other considered this additional revenue stream in the LCOC, to illustrate the cap contract value that would be required for the plant to be financially viable, Fig. 13 illustrates the three different LCOC's. As can be seen, PHES may be competitive with a new OCGT under the right conditions.

6. Discussion and conclusions

Our analysis illustrates that there is value in bulk energy services (including capacity value), however there is little marginal value in extending storage capacity beyond six hours. The analysis suggests that havings days of bulk energy storage capacity (as has been considered in other studies [8] is currently not valuable.

However, this conclusion does not take into account the cost structure of storage technologies, and the incremental cost of extending capacity may be minor in some cases. Further, our analysis demonstrated that there may be additional value in storage beyond six hours, due to the additional flexibility this enables, for managing the inability to perfect forecast wholesale prices. Though perfect foresight of electricity prices is a simplifying assumption, the analysis suggests it is a reasonable approximation, particularly for larger storage capacities, in the South Australian market.

Our analysis also shows there is considerable annual variation in potential arbitrage revenue for a merchant generator, with the annual revenue highly skewed to a few days per year. This annual variation is a function of the underlying volatility (and magnitude) of the electricity prices in those years. This is similar to an OCGT generator, and could be expected for a plant that provides similar energy services. The price spikes and volatility that are critical for the financial viability of peaking plants are similarly important for electricity storage.

The insensitivity to round trip efficiency is surprising, and contrasts with the results of Sioshansi et al. [15], who found round trip efficiency had a significant impact on the arbitrage value of storage. Increasing the efficiency from 70% to 80% was found to increase revenue by 30% in their study.

These different results are the consequence of different market designs and modelling approach. The PJM analysis does not include the capacity value of storage and only includes the energy arbitrage value (in a market with a significantly lower market price cap). The NEM being a fast market with a high cap price allows our analysis to capture the value of both.

There is a trend towards fast markets in the United States. Two thirds of all electricity supplied comes from regions with 5 min dispatch intervals, with both the ERCOT and SPP system recently becoming fast markets [22]. In these cases, our results are directly relevant.

In markets with alternative designs our results provide a useful proxy measure of capacity value (beyond energy arbitrage). As discussed in Riesz et al. [22] fast market are a more efficient approach than others, such as regulation reserves. Our results may therefore be considered as estimate of capacity value in an efficient market. The capacity value evaluated here, may be representative of the value of storage in capacity markets, (or other markets with alternative designs).

The findings comparing storage and OCGT are also broadly applicable and instructive. Storage can be expected to compete with, and provide similar value, to peak generation irrespective of the design of the market within which peak generation participates.

In the Australian market, merchant storage facilities (or generators) face challenges arranging finance, due to the high exposure to price and volume risk. Storage devices would likely use similar financial products as an OCGT (or other peaking generator) to manage these risks. Our analysis suggests that by selling cap contracts, a storage device can reduce the annual variability of revenue. The ability to generate revenue from arbitrage opportunities below $300 provides storage devices with competitive advantage over OCGTs.

Storage technologies may be able to offer some additional advantages over OCGT. For example, some technologies may be able to be optimally located in the electricity network, without being constrained by the need for a gas pipeline. On the other hand, technologies such as pumped hydro, may be constrained by geographical limitations.

6.1. Storage opportunities Australia

Australia's electricity system is currently excessively oversupplied, with capacity overhang at round 37%. As such, the short to medium term outlook for storage is poor as there is no need for new capacity (including peaking capacity) for the foreseeable future. This is also reflected in a recent decline in volatility and the current price of exchange traded cap futures (in $1–$2 range in the New South Wales and Victorian regions).

However, a scenario where new capacity (particularly storage capacity) might be required may emerge if there is significant withdrawal of older generation capacity, or a return to the drought conditions that prevailed in 2007–08. Alternatively, the outllook for storage may improve if renewable energy generation is increased to meet mandated targets, with a corresponding rationalisation of the emission intensive generation and/or gas prices increase. Increasing penetration of variable renewable energy will impact the arbitrage opportunity, due to the merit order effect. In times of high output, depression of wholesale prices [32–34], will likely increase the arbitrage opportunities in the below $300 price range, further increasing the competitive advantage and value of storage, beyond the capacity value.

6.2. Limitations and Further Work

A limitation of the approach in this paper is the use of static prices. Large-scale storage devices such as pumped hydro would be expected to have an impact on the electricity market and prices. The Sioshansi et al. [15] analysis found that a modest rated capacity of storage (0.7% peak load, 1.2% average load) reduced the value of storage arbitrage by as much as 10% [15].

In addition to this, the corresponding load shifting (and price shifting) results in a wealth transfer from generators to consumers, and net social welfare gains [15]. Further work considering the impact dynamic pricing has on the arbitrage opportunity and welfare affects in an energy only market would be beneficial.

It is important to note that this analysis only considers the value in the energy market. Storage may also be able to receive additional revenue by participating in the ancillary services markets, however this is likely to be small. Cost effective methods of storing electricity can help improve the efficiency and reliability of the grid, and provide additional societal benefits including:

- improved use of existing generation, transmission and distribution assets
- deferred investment in network assets and new generation, and
- helping to integrate renewable energy resources into the electricity system

Additional analysis of the network value of storage, and the best location within the electrical network would be valuable, particularly considering the large cost of power transmission and distribution in a sparsely populated country like Australia. This raises question about the best ownership structure for storage technologies, as identified in analysis from the U.S. [15,35]. Regulated entities such as transmission network service providers (TNSPs) may be best placed to capture these additional benefits, since they are better placed to value external public benefits. This may present challenges in the Australian regulatory framework, as regulated TNSPs are not able to participate in the wholesale market, and therefore cannot directly access the arbitrage and capacity value.

Similarly, there are questions about the best ownership arrangements within the market itself. That is, should storage devices be owned by consumers (e.g. retailers), producers (e.g. generators) or merchant participants. Some suggest merchant ownership is welfare maximising, as generators tend to under-use storage, and consumers tend to overuse storage [35].

The co-optimisation of storage and renewable technologies might also realise significant benefits (e.g. increased utilisation and productivity of network infrastructure), and provide additional insight into a potential transition to an electricity system with a higher penetration of renewable electricity.

The interaction between renewable energy and storage is particularly interesting. Storage technologies may become more viable (due to an increased volatility of prices), and renewable technologies may become reliant or storage technologies to arbitrage away the price differences that would otherwise exist due to the merit order effect. Understanding the effects of dynamic pricing and how renewable generation and the merit order effect play into this may be important for any attempts to decarbonise the electricity sector and increase renewable energy penetration.

Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2015.09.006.

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