

Energy transition in liberalised electricity markets:

Lessons from Australia

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*“When the wind of change blows, some people
build walls, others build windmills.”*

– Chinese proverb

Preamble

Renewable energy generation is being added to global electricity supply at a remarkable pace. A primary driver for this expansion has been the extraordinary cost reductions achieved by the sector (figure 1), in large part in response to both explicit and implicit climate policy measures and objectives. While a globally consistent and coherent climate policy remains elusive, research and development efforts, deployment policies and industrial policy motivated by the need to dramatically reducing carbon emissions have all contributed to the recent success of the renewable energy industry.

In December 2015, a historic global climate agreement was devised under the auspices of the United Nations Framework Convention on Climate Change at the 21st Conference of the Parties in Paris. This agreement includes a global goal to hold average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels. According to the International Energy Agency, the average CO₂ intensity of electricity will need to fall from 0.411t/MWh in 2015 to 0.015t/MWh by 2050 (IEA 2016). Any future scenarios that meet this objective will necessarily involve significantly increased penetrations of renewable energy (Holz and Von Hirschhausen 2013).

While many studies have concluded that such a substantial de-carbonisation of the electricity sector with renewable technologies is feasible, to date such studies have tended to focus on the technical viability of systems with high penetration of renewables to reliably supply electricity. In Australia alone¹, there are now several such studies that show that 100% renewable energy systems are technically capable of meeting our electricity requirements (AEMO 2013a; Elliston, MacGill, and Diesendorf 2013; Wright and Hearps 2010). Challenges remain, but the questions

¹For a review of high penetration renewable energy studies, see Reedman (2012).

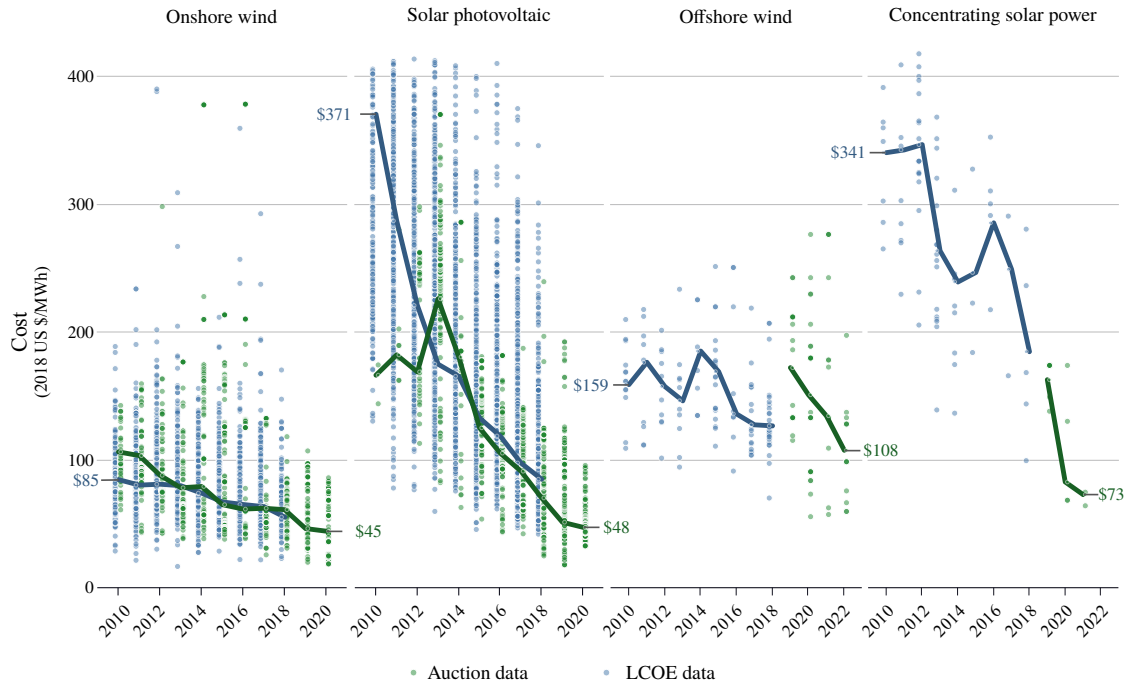


Figure 1: Cost and auction results for solar PV, onshore and offshore wind, and concentrating solar thermal projects (global weighted average values) [data source: IRENA (2019)].

are now shifting from technical viability to economic feasibility (Riesz 2012).

Notwithstanding this, reaching high penetration of renewable energy requires more than technical or economic feasibility. There is a particular need for careful consideration of market design (IEA 2016). In this thesis, I explore the way market design issues are impacting the penetration of renewable energy in the context of the National Electricity Market (NEM) in Australia, with a particular focus on the experience in South Australia.

Three different aspects of energy market design are considered in this thesis. Firstly, I consider how the current market design values energy arbitrage and storage. Secondly, I consider how specific market rules related to dispatch and settlement intervals impact the technology mix and capabilities, and effect the efficiency of the market itself. Finally, I consider how new technologies impact on secondary markets such as frequency control which have typically been provided by thermal generation.

The thesis begins with a review of the energy-only market structure and design. This includes discussion of the ‘capacity cycle’ from both a historic and forward looking perspective, and how it is impacted by renewable technologies. The suitability of traditional ‘capacity over-

hang’ heuristics in a system where older technologies are displaced or replaced by fundamentally different technologies is discussed. I also explore the interaction with historical problems that remain contested and unresolved for energy-only markets, such as the so-called ‘missing money problem’, as well as the viability of energy-only markets in high penetration renewable energy systems.

The second chapter specifically looks at the contextual settings of the Australian NEM, and in particular, the South Australian (SA) market region. Considered in isolation to the NEM, South Australia has an exceptionally high penetration of renewable energy, even by international standards, making this region a noteworthy case study in energy system transition. The historical and geographical context in which SA sits is nonetheless critical to understand both its place in the NEM and how it has responded to date. As such, this chapter includes an overview of the SA market, and important characteristics including energy mix, the size of the market, the impacts of the recent exit of coal generation and resultant changes in market concentration.

The third chapter focuses on the way increasing renewable energy generation and price volatility give rise to opportunities for storage technologies in an energy-only market, using the NEM and SA as an example. In particular, I demonstrate that the main driver for storage options in an energy-only market is price volatility which, in turn, is dependant on capacity requirements to meet particular reliability settings. I show that storage technology economics are very similar to the economics of traditional forms of peak generation in this respect, and common hedging and contracting strategies used by peak generators would be suitable to finance storage assets. The analysis suggests that in energy only markets storage may also derive a competitive advantage over traditional peaking assets by deriving revenue from arbitrage opportunities, in addition to capacity payments. A case study involving Pumped Hydro Energy Storage (PHES) demonstrates that in certain circumstances, it may already have a competitive advantage over Open Cycle Gas Turbines (OCGT).

The fourth chapter looks at a particular market-market design element, and investigates how this impacts the different technologies, and the efficiency of dispatch in the market. Specifically, I examine a particular characteristic of the NEM in which physical dispatch (which occurs on a 5-minute interval basis) is misaligned with financial settlement (which occurs on a 30-minute interval basis), and the incentives and outcomes that result. Drawing on the analysis and methods

from the previous chapter, the effect and value of aligning these intervals is evaluated for storage technologies. The impact on other technologies, including demand side response and the costs to the system of ‘gaming’ this particular rule is also estimated. I find that market rules have a significant impact on the operation of an energy-only market under transition (see figure 2).

The fifth chapter examines how, in a high penetration renewable market, storage technologies are able to contribute to security of supply, allowing for changes in traditional market management strategies. Specifically, I look at how lithium-ion batteries have participated in the existing frequency control framework, and the implications for the provision of system security in the longer term.

The final chapter summarises and concludes the thesis, including a discussion of further avenues for analysis.

A range of outputs have been generated as part of this thesis. In particular, chapter 3 was published as a journal article, while the analysis in chapter 4 was submitted and contributed to the Australian Energy Market Commission, as part of its assessment of a rule change. Finally, the analysis draws heavily on market data from the Australian Energy Market Operator (AEMO). In undertaking this analysis, substantial amounts of the publicly available data provided by AEMO have been curated in a large database that continues to be updated in real time. This database now exists as the ‘openNEM’ project - an online resource that is now both open access and open

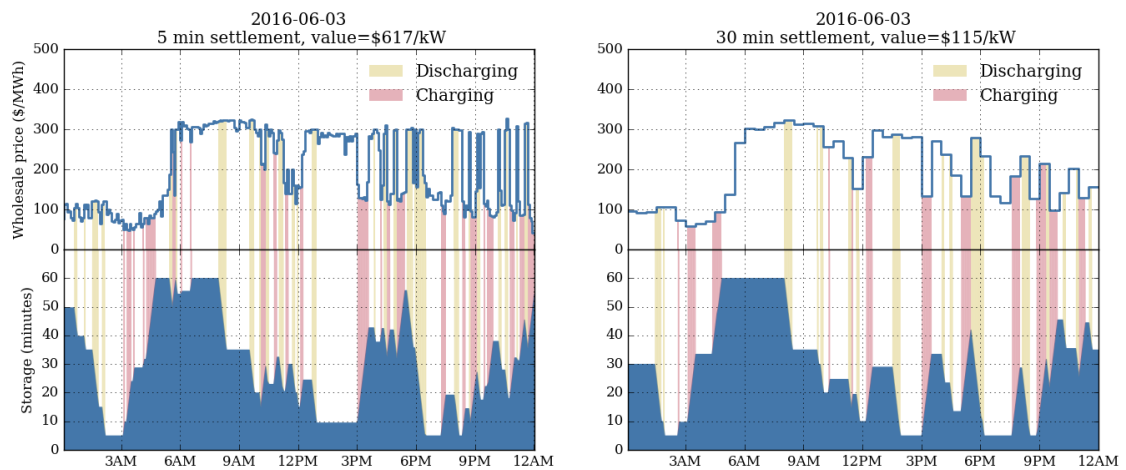


Figure 2: Results of analysing the impact of aligning settlement on dispatch on optimal operation. A relatively straight forward change in market design yields a 6-fold increase revenue.

source. Further details are provided in appendix F.

Prior to this thesis I was the lead author of a journal article that investigated the merit order effect of rooftop solar in Australia (McConnell et al. 2013), and was co-author of a paper published in the Journal of Environmental Sociology (Haines and McConnell 2016) and another in the electricity journal (Sandiford et al. 2015). Whilst these are not included or part of this thesis, these work have informed my knowledge of the research area.

Declaration

This is to certify that:

- (i) the thesis comprises of only my original work towards the degree of Doctor of Philosophy except where indicated in the preamble,
- (ii) due acknowledgement has been made in the text to all other material used, and
- (iii) the thesis is fewer than 100,000 words in length, exclusive of tables, maps, bibliographies and appendices.

A handwritten signature in black ink, appearing to read 'Dylan McConnell', written in a cursive style.

Dylan McConnell

February 2020

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First and foremost, I would like to thank my supervisor Mike Sandiford. Mike has been a constant source of encouragement and support throughout my time in the world of research, beginning well before I began the PhD journey. Over the years, Mike has been a very patient, tolerant and compassionate mentor on matters both within and beyond the walls of academia. He's been a constant advocate and champion for me and my work.

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I would also like to acknowledge the important role that the Australian German Climate and Energy College has played during over the completion of the thesis. The College and it's members have provided the critical supportive and encouraging environment to navigate through the the inevitable trials and tribulations of the PhD process. The amazing and fantastic cohort of students have made invaluable contributions to both my academic progress, and development into a more rounded human being.

Finally I would like to thank the many many other people that have accompanied and supported me through this project, and life in general. Without their support in keeping me going, it's difficult to imagine progressing to the finish line. In particular, I would like like to thank Alex who has been a particularly significant fellow-traveller and source of respite on this journey. Mandy's support and companionship has also been highly valued, and perhaps critical in getting me over the line. Laura, Leigh and Susannah have also provided much needed comfort and relief over the years. The biggest thanks of all must of course go to my family, particularly Mum and Dad. Their unconditional support and selflessness over the years deserves the biggest acknowledgement of all.

Contents

List of Figures	xiv
List of Tables	xviii
Acronyms and abbreviations	xxi
1 Introduction	1
1.1 Liberalised electricity markets	1
1.1.1 The ‘Capacity Cycle’	3
1.1.2 Merit Order Effect	4
1.1.3 State of research	6
1.2 Emerging issues for energy-only markets	10
1.2.1 Resource adequacy and the “missing money” problem	12
1.2.2 The emergence of new technologies	13
1.3 Summary	16
2 Context	19
2.1 The Australian National Electricity Market	19
2.1.1 The Market Price Cap, reliability and volatility	20
2.1.2 Hedging and contracting	24
2.1.3 The value of energy and capacity	28
2.1.4 Renewable energy support schemes	31
2.2 The South Australian market region	31

2.2.1	Demand	33
2.2.2	Generation and interconnection	34
2.2.3	Load duration curves	38
2.3	Wholesale power price dynamics in South Australia	41
2.3.1	Renewable energy generation and merit order effects	43
2.3.2	Gas demand and prices	49
2.3.3	Competition	52
2.3.4	Security of supply	62
2.4	Summary	64
3	Value of storage in energy-only markets	65
3.1	Introduction	65
3.2	Assumptions and methods	71
3.3	Relationship between storage configuration and value	73
3.4	Impact of forecasting on arbitrage value	79
3.5	Capacity value of storage	81
3.5.1	Extended case study for South Australia	83
3.6	Discussion and Conclusions	88
4	Fast markets, and the value of aligning settlement and dispatch	93
4.1	Introduction	93
4.2	‘Fast Markets’	94
4.3	The ‘5-30 problem’	95
4.3.1	Allocative inefficiency of average pricing	95
4.3.2	Perverse incentives: rebidding	97
4.3.3	Flexible generation incentives	99
4.4	Modelling a ‘fast market’ in South Australia and the NEM	103
4.4.1	Model description	104
4.4.2	Simulation scenarios	106
4.5	Results	108
4.5.1	Perfect scenarios	109

4.5.2	The impact of forecasting	109
4.5.3	Impact on cap contract	112
4.6	Case study: Lithium battery storage	114
4.7	Conclusion	116
5	The future of frequency control and system security	117
5.1	Frequency control in the NEM	118
5.1.1	Contingency services	118
5.1.2	Regulation services	119
5.1.3	FCAS cost and demand	120
5.2	The Hornsdale Power Reserve	123
5.3	Co-optimisation of FCAS and Energy	127
5.4	Results	130
5.5	Discussion - the future of frequency control	137
5.5.1	Alternative options: Fast frequency response?	138
5.5.2	Conclusion	141
6	Discussion and conclusions	143
6.1	Competitive electricity markets: Questions remain about design, performance and future	146
	References	147
	Appendix A Development of the National Electricity Market	157
A.1	Pre 1990: State Owned Electricity Monopolies	157
A.2	1985-1990: Industry Commission and other Inquiries	158
A.3	1990-1995: Competition Policy, the Hilmer Review and Industry Restructuring	159
A.4	1996-2001: The National Electricity Law	161
A.5	2002: The Parer Review and the current regulatory framework	162
	Appendix B NEM and SA - additional analysis	165
B.1	Load duration curves	165

B.2	Power stations by regional basis size, FY16	167
B.3	Gas generation SA	168
B.4	Forecasting	169
B.5	Evolution of Load Duration Curves in South Australia	170
B.6	Breakdown of Load Duration Curve in SA	171
Appendix C Levelised cost of capacity assumptions		173
Appendix D 5 minute settlement		177
D.1	Sensitivity - battery cost of capacity, 5yr economic life	177
D.2	QLD price spike analysis	179
Appendix E Co-optimisation problem description		181
E.1	Full model description	181
Appendix F The openNEM project		183
F.1	Website	183
F.2	Basic: data access through the website	186
F.3	Advanced: Application Programming Interface (API)	187
F.4	Source Code	190
F.5	Data sets	191
Appendix G Datasets		193

List of Figures

1	Renewable energy technology cost reductions'	ii
2	Impact of aligning settlement and dispatch on optimal operation	iv
1.1	Theoretical electricity supply curve	2
1.2	The 'capacity cycle'	4
1.3	Impact of large scale wind and solar supply curve	5
1.4	Impact of distributed solar on supply curve	6
1.5	Modelled impact of solar PV in the NEM	8
1.6	Spatial distribution of rooftop solar	9
1.7	Renewable energy technology cost reductions'	14
1.8	The new 'capacity cycle'	16
2.1	Wholesale electricity prices across the four mainland regions	22
2.2	Capacity cycle in Australia	23
2.3	Contract coverage for retails and generators	25
2.4	Cap contract money flows	27
2.5	Illustrative risk management approach using contracts	28
2.6	Hedged wholesale prices and volatility in the four main NEM regions	29
2.7	Monthly hedged wholesale prices and volatility in the four main NEM regions . .	30
2.8	Renewable energy generation and investment in the NEM	32
2.9	Annual consumption and demand in South Australia	34
2.10	South Australian supply trends	35
2.11	South Australian annual electricity supply by generation	35

2.12	South Australian capacity by generation type	37
2.13	Comparison of South Australian dispatch profiles	37
2.14	Load duration curve for South Australia	38
2.15	Net load duration curve for South Australia	39
2.16	evolution of the demand and net demand distributions over time	40
2.17	Residual energy vs residual peak	41
2.18	Wholesale price in South Australia, showing scarcity and negative prices	42
2.19	Number of scarcity and negative prices in South Australia	42
2.20	Relationship between wind generation, wholesale prices and volatility	46
2.21	Relationship between interconnector flow, prices and volatility	47
2.22	Relationship between gas generation, wholesale prices and volatility	47
2.23	Historical and projected gas demand	49
2.24	Fuel cost projections for Torrens Island	50
2.25	Relationship between South Australian electricity and gas prices	51
2.26	Monthly Pivotal Supply Index for the mainland NEM regions	54
2.27	Spark spread for a typical CCGT	55
2.28	Systematic withdrawal of supply, Angaston, 4 Sept 2015	58
2.29	Systematic withdrawal of supply, Angaston, 27 Aug 2015	59
2.30	Output at Torrens Island A and B power stations in MW, 7 th July, 2016	61
2.31	Rebidding at Torrens Island	62
2.32	Example of forced outages at two different power stations	63
3.1	Relative variation in daily demand, for the four main NEM regions	69
3.2	Rolling standard deviation of $\log_{10}$ of the regional price for the four main regions	70
3.3	Optimal operation of a storage device, week in January, 2012	73
3.4	Optimal operation characteristics, for winter and summer months of the year . .	74
3.5	Value of Storage by financial year and storage capacity	75
3.6	Volume-weighted electricity prices compared with number of days reaching 38°C	75
3.7	Normalised value of storage	76
3.8	Revenue duration curves & histogram of daily revenue	78

3.9	Pre-dispatch forecast accuracy	80
3.10	Forecast vs Perfect Foresight	81
3.11	Cap contract prices	82
3.12	Value of a contracted storage plant	83
3.13	Levelised cost of capacity for an OCGT and PHES	86
3.14	Levelised cost of Capacity comparison	87
4.1	Allocative inefficiency resulting from misalignment of trading & dispatch intervals	96
4.2	Distribution of dispatch prices with trading intervals, 2008-2009	98
4.3	Distribution of dispatch prices with trading intervals, 2014-2015.	98
4.4	Ratio of last dispatch interval price spikes	99
4.5	Comparison of generator outcomes, with a price spike early in the trading interval	101
4.6	Comparison of generator outcomes, with a price spike late in the trading interval	102
4.7	Optimal operation of storage device for a representative day in South Australia .	103
4.8	Expected trading price for a trading interval with an unanticipated price spike .	107
4.9	Impact of forecast inaccuracy on value capture	109
4.10	Comparison of operation under the differing pricing regimes	110
4.11	Value of storage under different pricing regimes, FY15	111
4.12	Value of storage under different pricing regimes, FY16	111
4.13	Cap contract revenues & penalty payments under different pricing regimes, FY15	113
4.14	Cap contract revenues & penalty payments under different pricing regimes, FY16	113
4.15	Contract revenues & penalties for storage under different pricing regimes, FY15 .	115
4.16	Contract revenues & penalties for storage under different pricing regimes, FY16 .	115
5.1	Contingency response in the NEM	119
5.2	Cost of FCAS services in the NEM over time	121
5.3	Regulation enablement in South Australia	122
5.4	Flexibility of Hornsdale Power Reserve battery	124
5.5	Frequency response of HPR following trip of large load.	125
5.6	Enablement of HPR in the raise regulation market against output	125
5.7	Accuracy and speed of regulation response from the HPR battery	126

5.8	Accuracy and speed of regulation response from a large steam turbine	126
5.9	Co-optimised output from a utility battery, 2 Feb 2017	131
5.10	Co-optimised output from a utility battery, 6 Feb 2017	132
5.11	Co-optimised value of storage in South Australia	133
5.12	Co-optimised value of storage in South Australia, with extremes capped	135
5.13	Revenue streams for the Hornsdale Power Reserves	136
5.14	High inertia and low inertia contingency response	139
5.15	Impact of FFR on contingency response	140
B.1	Load duration curves for the main NEM regions in 2015.	166
B.2	Normalised density distribution of of AEMO forecasts error	169
B.3	Load Duration Curves for South Australia over the past seven years	170
B.4	Net Load Duration Curves for South Australia over the past seven years	170
B.5	Net Load Duration Curves for South Australia by technology	171
D.1	Financial viable cap contracts for lithium battery, FY15	178
D.2	Financial viable cap contracts for lithium battery, FY16	178
F.1	OpenNEM landing page screen shot	184
F.2	Basic openNEM navigation options	184
F.3	Screen shot showing a week of generation data in SA	185
F.4	Screen shot showing a year of generation data for Vic	185
F.5	Export options	186
F.6	Example of csv file downloaded from openNEM website	187
F.7	Example of ipython notebook running opennempy	188
F.8	Example of ipython notebook running opennempy	189

List of Tables

1.1	Comparison of merit order studies discussed in this chapter	7
2.1	Number of high price settlement period events in each of the four mainland NEM regions for financial years FY10 through FY16, and July 2016.	30
2.2	Contribution of renewable energy support schemes to retail electricity tariffs . . .	44
3.1	Comparison of volume weighted prices (VWP) and median for charging (subscript c) and discharging (subscript d) under optimal operation in SA since 2012	77
4.1	Distribution of price differences between trading and dispatch intervals, 2015 . .	97
4.2	Proportion of market revenue in trading intervals with price differences	97
4.3	Rate of Change (RoC) by technology, as offered to the NEM, based on the offers placed by generators in the NEM. For thermal technologies, these figures are not indicative of ‘cold start’ times.	100
4.4	Trading price and dispatch statistics for South Australia for FY15 and FY16 . .	104
4.5	Battery costs (\$/kWh)	114
5.1	All eight FCAS markets in the NEM	120
5.2	Percentage of time capacity utilised across each market	134
5.3	FCAS market price statistics	134
B.1	Size of NEM coal generators in the relative to median regional demand	167
B.2	Energy output and gas consumption for gas generators in SA, 2015	168

C.1	OCGT data	174
C.2	Pumped hydro data	175
D.1	Intervals with price spikes in last dispatch interval	179
F.1	Datasets hosted on the openNEM platform	191

Acronyms and abbreviations

ACCC Australian Competition and Consumer Commission.

AEMC Australian Energy Market Commission.

AEMO Australian Energy Market Operator.

AER Australian Energy Regulator.

ASX Australian Stock Exchange.

CCGT Combined Cycle Gas Turbine.

COAG Council of Australian Governments.

CST Concentrating Solar Thermal.

ED Economic Dispatch.

ERCOT Electric Reliability Council of Texas.

ETF Exchange Traded Future.

FCAS Frequency Control and Ancillary Services.

FERC Federal Energy Regulatory Commission.

GPG Gas Power Generation.

GWh gigaawatt hour.

HHI Herfindahl-Hirschman Index.

IEA International Energy Agency.

LCOC Levelised Cost of Capacity.

LCOE Levelised Cost of Energy.

LGC Large-scale Generation Certificates.

LNG Liquid Natural Gas.

LoLP Loss of Load Probability.

LRET Large-scale Renewable Energy Target.

LRMC Long Run Marginal Cost.

MPC Market Price Cap.

MW megawatt.

NEG National Energy Guarantee.

NEM National Electricity Market.

NSW New South Wales.

NTNPD National Transmission Network Development Plan.

OCGT Open Cycle Gas Turbine.

OFGEM Office of Gas and Electricity Markets.

OTC Over-The-Counter.

PHES Pumped Hydro Energy Storage.

PJ petajoule.

PPA Power Purchase Agreements.

PSI Pivotal Supply Index.

PV Photovoltaic.

QLD Queensland.

RET Renewable Energy Target.

SPP Southwest Power Pool.

UC Unit Commitment.

USE Unserved Energy.

VIC Victoria.

VoLL Value of Loss Load.

VWP Volume Weighted Price.

Chapter 1

Introduction

1.1 Liberalised electricity markets

Since the late 1980's, a number of countries around the world have progressively reformed their electricity supply industries (Sioshansi 2006). Before this, electricity supply was centrally delivered and coordinated by a state monopoly, and were considered inefficient. The reforms were generally motivated by the efficiency and productivity gains promised by the introduction of competition in the sector. Typically the reforms involved the introduction of an electricity market, while simultaneously restructuring and privatising state-owned generation assets, and opening up the system to allow private firms to enter the market and compete. These systems, which are characterised by competitive markets with reduced state involvement, are commonly referred to as liberalised electricity markets. Whilst both the market design and the degree of restructuring and privatisation varies from country to country, some of the basic components are universal to all competitive liberalised electricity systems (Joskow 2006b).

Many industrialised nations electricity markets can be characterised as *energy-only* markets (Sioshansi 2006)¹. In such markets electricity generation capacity is offered into a central market, coordinated by a single market operator. The market typically operates a uniform clearing price auction, with the market operator dispatching sufficient capacity to meet demand, whilst ensuring

¹In recent years the UK has introduced a capacity market, while several of the US markets have capacity markets

the lowest cost combination of generation to ensure reliable operations of the power system.

Generation capacity is offered into the market by participants throughout the network. Conceptually generation capacity is ranked by offer price, and is dispatched in ‘order of merit’ (from lowest to highest price) until a target demand has been met. The last generator dispatched to clear the market sets the uniform market price, which is received by all generators. This system is variously referred to as a “*Security Constrained Economic Dispatch*”, “*Price Based Economic Dispatch*” or “*Merit Order Dispatch*” system. Figure 1.1 shows an illustrative supply curve, and the set price for meeting a particular demand.

In energy only markets, generators are typically expected to offer capacity at (or close to) the marginal cost of production, that is, the cost to produce a single additional unit of electricity. Theoretically, offering capacity at the marginal cost results in optimal electricity pricing, being both profit maximising for the generator, whilst simultaneously minimising total system costs (Green and Newbery 1992). Historically, in markets dominated by fossil energy generation, the marginal cost of production has typically been dominated by fuel costs.

In energy-only markets, both variable costs, such as fuel, and fixed costs, such as capacity, need to be recovered in the revenue solely derived from energy output. Energy-only markets allow prices to rise to extreme values during periods where reserves are scarce². This is known

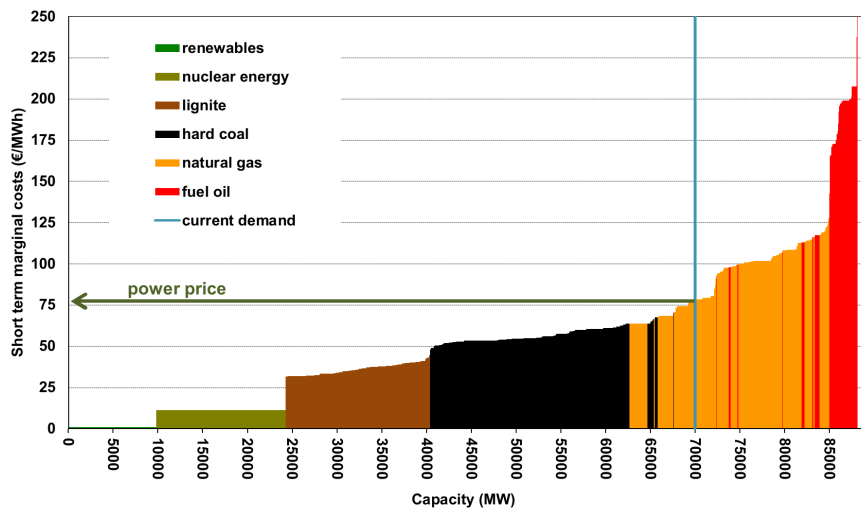


Figure 1.1: Conceptual illustration of an electricity supply curve, the set price for a given demand cycle, [source: Cludius et al. (2014)].

²In addition, prices can also drop to very low, sometimes negative, prices in times of excess production

as *scarcity pricing* allows generators to recover fixed capital costs. Extreme pricing during such *scarcity events* incentivises investment in peak generation, such as Open Cycle Gas Turbine (OCGT) and distillate (diesel) capacity. Energy-only markets are thus specifically designed with high sensitivity to the supply-demand balance, with prices typically capped at a high value. In theory, the market price cap³ should be high enough that the spot prices “*provide a revenue stream that matches total costs (both fixed and variable) of the optimal fleet of efficient generators*” (Nelson, Reid, and McNeill 2014; Sioshansi 2008).

Unlike most other commodity markets where inventory management can be used to smooth production schedules and meet variable demand, there are currently limited economic options for large-scale electricity storage (Anderson, Hu, and Winchester 2007; Nelson, Reid, and McNeill 2014). Consequently consumption and production must instantaneously match in electricity markets. The highly variable nature of electricity demand (on inter-day, intra-day and inter-seasonal time-scales), combined with a design sensitive to the supply demand balance means that price volatility is a common feature of competitive wholesale markets. In addition to ensuring capacity is available for dispatch during rare high-demand occasions and that generators can recover fixed costs, the price volatility associated with scarcity events also signal large consumers to contract supply.

1.1.1 The ‘Capacity Cycle’

To manage the financial risks associated with volatile prices, market participants use a variety of hedging strategies. The specifics of the hedging and contracting arrangements in the Australian context are discussed further in section 2.1.2.

Energy-only markets expose both generators and consumers of energy to the so-called ‘*capacity cycle*’. This cycle is driven by the ‘reserve margin’, which represents the difference between the available (firm) capacity and the peak demand.

As illustrated in figure 1.2 the cycle functions as follows:

1. Investment in new capacity drives up reserve margins
2. Prices fall, investment in new generation capacity stalls

³This is similar to, but not the same as, the Value of Lost Load (VoLL) as is considered in other markets, and is discussed further in chapter 2.

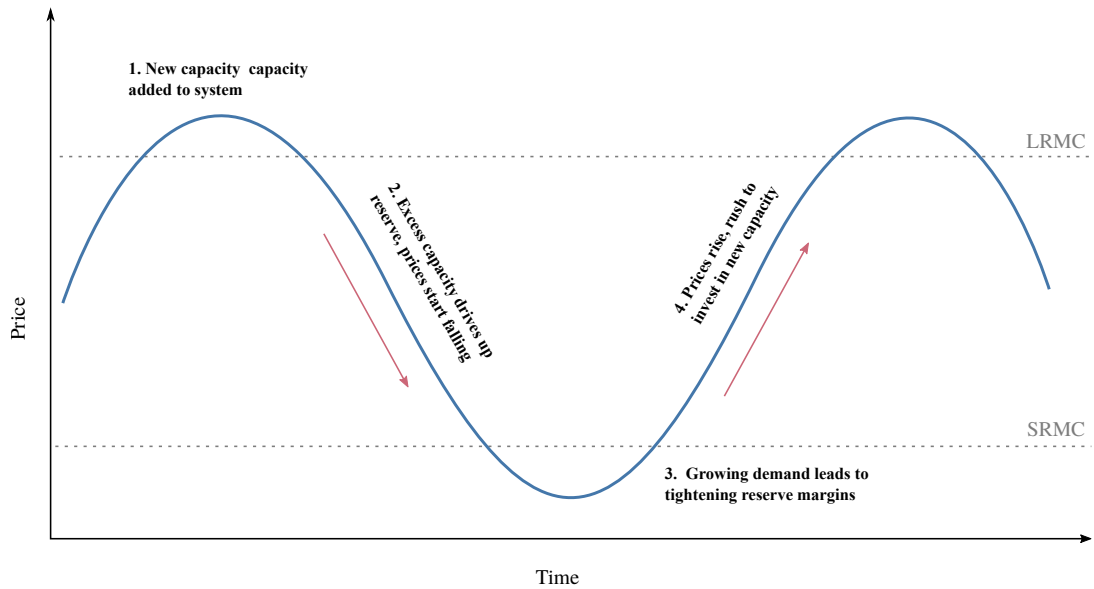


Figure 1.2: Conceptual illustration of the capacity cycle, [adapted from Steed and Laybutt (2011)].

3. Under-investment together with growing demand leads to tightening reserve margins
4. Prices rise, firms invest in new capacity

Tightening of the supply-demand balance and reserve margins causes prices to reach the market price cap more often. When average prices rise above the long run marginal cost (LRMC) of new entrant generation, the signal is for new investment. As new generation is added (or demand decreases), eventually the excess capacity⁴ creates oversupply. Consequent downward pressure causes market prices to fall below the long run marginal costs of production, discouraging new entry of generation. Historically a reserve margin or capacity overhang of around 15% is generally considered adequate to ensure system security, and a balanced system (Steed and Laybutt 2011), though this varies within individual markets depending on factors such as the shape of the demand curve.

1.1.2 Merit Order Effect

The addition of significant levels of renewable energy capacity has been shown to markedly reduce wholesale spot prices in liberalised electricity markets. This phenomenon, known as the “*merit*

⁴Also known as ‘capacity overhang’

order effect”, is demonstrably impacting electricity wholesale prices in Australia and abroad.

On one level, this is hardly surprising. As discussed in the previous section, the addition of new supply without compensating withdrawals will increase the *capacity overhang* as well as additional competition, putting downward pressure on wholesale prices. Indeed this phenomenon is not particular to renewable energy: adding any new generation capacity will affect the capacity cycle and lower prices (as is demonstrated in figure 1.2). This is a particular issue for very large capacity entrants, such as thermal coal and nuclear plants. For new entrants and independent power producers, long term *power purchase agreements* (PPAs) are practically essential to finance new developments⁵. Vertical integration can also mitigate the risks associated with the capacity cycle, and is a common strategy among firms in the Australian market.

Because renewable technologies such as solar PV and wind have no fuel costs their short-run marginal costs are negligible, and so their effect on merit order dispatch can be particularly acute (Jensen and Skytte 2002). Under typical market design rules (see section 1.1) it is now well demonstrated that new-entrant renewable energy has a disproportionate effect on the merit order, with the result that prices frequently drop to zero or lower in markets with high proportions of renewable generation (Edenhofer et al. 2013). Figure 1.3 illustrates the impact centralised wind and large-solar, both low short-run marginal cost technologies, on a hypothetical supply curve.

Distributed solar generation such as rooftop solar PV is generally not traded through the

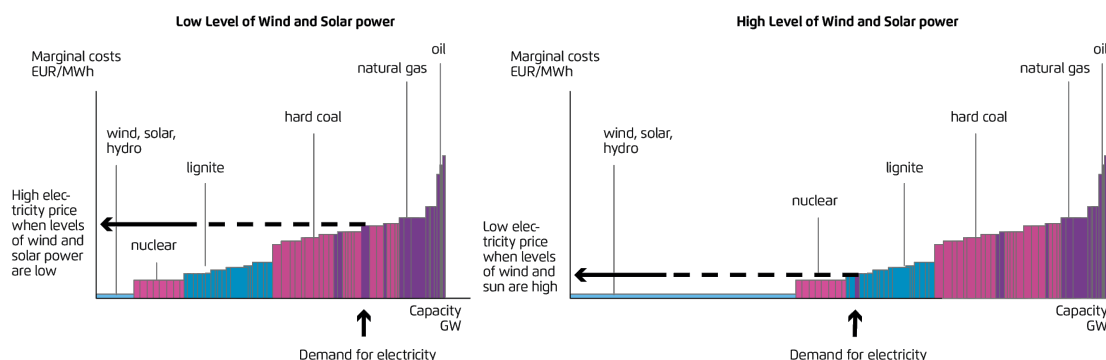


Figure 1.3: Impact of wind and solar, both low short-run marginal cost technology, on a hypothetical supply curve. In merit order dispatch pricing, participants generally offer capacity at the short-run marginal cost, resulting in a supply curve like the ones shown here. Prices are set by the least cost supply needed to meet demand, [source: Agora Energiewende (2013)].

⁵Merchant financing is possible, but very rare. Debt financing is practically impossible without a credit worthy off-taker in Australia

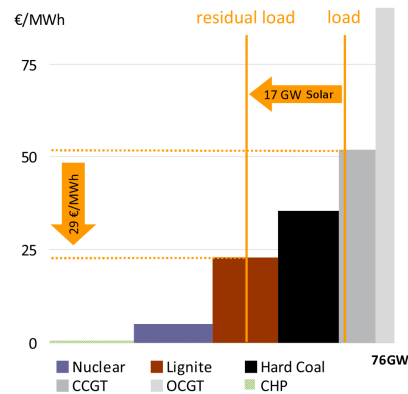


Figure 1.4: Illustration of the merit order effect arising from distributed solar generation, adapted from Hirth (2013).

central dispatch system, and so is revealed to markets via an apparent reduction in demand and a reduced demand target, rather than as additional low marginal cost supply. However, the impact on the wholesale spot price is similar to centrally dispatched renewable generation. Rather than adding to the bottom of the supply curve, distributed PV subtracts from the demand curve (see figure 1.4). As with centrally dispatched renewable generation, the end result is that a lower marginal cost generator sets the dispatch price.

1.1.3 State of research

Modelling electricity markets

There are two general approaches to assessing or estimating the impacts of technology change and phenomenon such as the merit order effect: simulation based studies and empirical analysis. The first approach typically involves electricity market simulation based on either real (historical) data, hypothetical data, or a combination of both. The second approach is econometric, using historical data. Each technique has its benefits and drawbacks with respect to analysing technology changes in electricity markets. Electricity market models may be better placed to capture and explore long term effects, however they are sensitive to the input assumptions and available market models generally have significant limitations (Cludius et al. 2014). Econometric techniques do not rely on so many assumptions, but can only capture short-term affects (Cludius et al. 2014).

Paper	Approach	Technology	Country
Sensfuß, Ragwitz, and Genoese (2008)	Sim.	All	Germany
Weigt (2009)	Sim.	Wind	Germany
Jónsson, Pinson, and Madsen (2010)	Emp.	Wind	Denmark
Sáenz de Miera, Río González, and Vizcaíno (2008)	Sim.	Wind	Spain
McConnell et al. (2013)	Sim.	Solar	Australia
Traber and Kemfert (2009)	Sim.	All	Germany
Rathmann (2007)	Sim.	All	Germany
Hirth (2013)	Sim.	All	Europe
Cludius et al. (2014)	Emp.	Wind & Solar	Germany
Tveten et al. (2013)	Emp.	Solar	Germany
Forrest and MacGill (2013)	Emp.	Wind	Australia
Clò, Cataldi, and Zoppoli (2015)	Emp.	Wind & Solar	Italy
Brancucci Martinez-Anido, Brinkman, and Hodge (2016)	Emp.	Wind	United States
Kyritsis, Andersson, and Serletis (2017)	Emp.	Wind & Solar	Germany
Csereklyei, Qu, and Ancev (2019)	Emp.	Wind & Solar	Australia

Table 1.1: Comparison of merit order studies discussed in this chapter

Table 1.1 lists the main merit order studies covered in this chapter, the approach they used and the technologies covered. As can be seen, most of the studies listed are focus on wind generation. For a more comprehensive list, which also contains predominately simulated wind studies, see Wurzburg, Labandeira, and Linares (2013).

Merit order effect research

There are now numerous studies that have analysed the impact of renewable generation on merit order pricing in many markets, including the NEM in Australia. In one of the first such studies in Germany, Sensfuß, Ragwitz, and Genoese (2008) coined the term ‘the merit order effect’. Sensfuß, Ragwitz, and Genoese (2008) analysis argued that the value of the merit order effect in Germany in 2006 exceeded the value of support payments made to renewable generators. Since then, several other studies have quantitatively determined the value of the merit order effect and the impact on wholesale pool prices, particularly with respect to the effects of wind power. Weigt (2009) also investigated the effect of wind power in Germany, obtaining similar results similar to Sensfuß, Ragwitz, and Genoese (2008). Munksgaard and Morthorst (2008) and Jónsson, Pinson, and Madsen (2010) found that the feed-in of wind decreased wholesale prices by as much 14% in Denmark. Wind generation was also found to depress prices in Spain by 25% in 2007 by (Sáenz de Miera, Río González, and Vizcaíno 2008). A review of the effect in various European

countries can be found in Morthost et al. (2010). Wurzburg, Labandeira, and Linares (2013) provide a detailed review of studies on the merit order effect.

In Australia, wind renewable generation is demonstrably impacting wholesale spot prices in jurisdictions such as South Australia where wind accounts for some 35% of generation capacity and 41.7% of generation output. In South Australia, negative wholesale spot price events have become increasingly common in the last decade, and incidence of negative pricing correlates with periods of high wind power generation (Boerema, Kay, and MacGill 2010; Cutler et al. 2011). More recently, (Forrest and MacGill 2013) quantified the impact of growing wind penetrations in the NEM, using a novel econometric methodology for assessing the effect.

Compared to wind, there has been less analysis of the merit order effect of solar, particularly using actual historical data. For example, of the 20 studies reviewed by Wurzburg, Labandeira, and Linares (2013), 13 exclusively investigated the impact of wind, while the remaining studies considered all renewables, and were predominantly modelling studies rather than empirical studies.

Since the Wurzburg review, several new publications on the merit order effect from solar

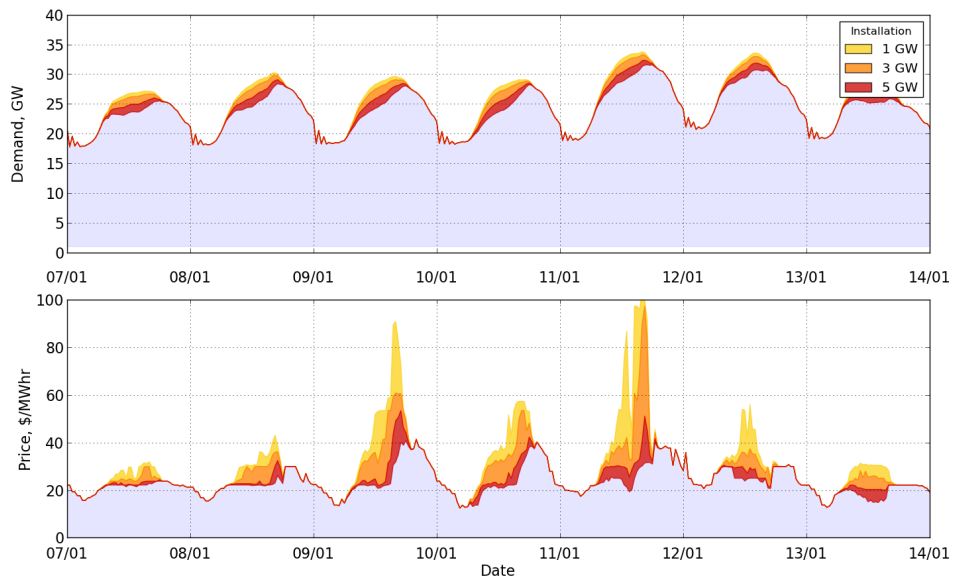


Figure 1.5: Modelled impact of solar PV on the Australian National Electricity Market [source: McConnell et al. (2013)].

generation have been produced. Tveten et al. (2013) provided the very first study that specifically determines the merit order effect of solar empirically. Cludius et al. (2014) followed soon with a similar analysis that evaluated the influence of solar, separate from wind. McConnell et al. (2013) and Hirth (2013) both evaluate the impact of the merit order effect with a market modelling approach. More recently, there have been several studies that look at the impact of both wind and solar using econometric techniques. This includes (Csereklyei, Qu, and Ancev 2019) in Australia, (Kyritsis, Andersson, and Serletis 2017) in Germany and (Clò, Cataldi, and Zoppoli 2015) in Italy.

The relatively smaller number of solar merit order studies, and particularly empirical studies, partly reflect the difficulties in obtaining high quality data on solar output. In Australia there are over 2 million⁶ individual solar systems (see figure 1.6 which illustrates the distribution of installed solar capacity). As the Australian market operator has noted, this makes *‘monitoring the output from all systems problematic’* (AEMO 2012). Attempts to estimate the effect by McConnell et al. (2013) used artificially constructed ‘ideal’ solar generation data.

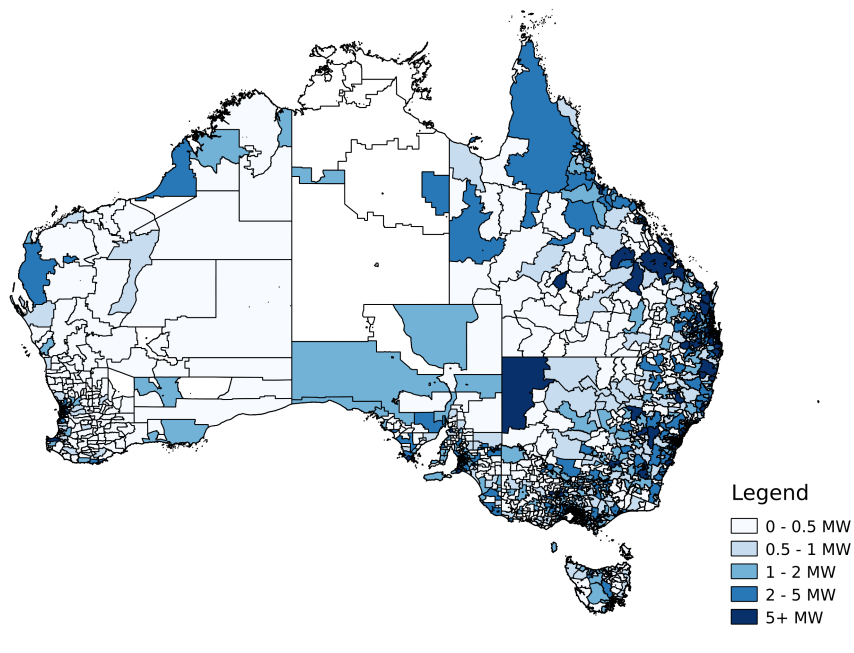


Figure 1.6: Spatial distribution of rooftop solar capacity in Australia, source: own illustration, using data from Clean Energy Regulator (2019)

⁶As of 1 Jan 2019

The modelling conducted by McConnell et al. (2013) had several significant limitations, most notably of which was the *ceteris paribus* approach. Bidding behaviour was assumed to be static and therefore unresponsive to the effects of solar generation. Given there is over 6GW of solar capacity currently⁶ installed (Clean Energy Regulator 2019), this is unlikely to be a valid assumption. Further, analysis by Parker (2012) illustrates that bidding behaviour has demonstrably changed in response to wind generation. Similar responses to the change in demand profile caused by solar should also reasonably be expected. Other limitations to the McConnell et al. (2013) study included a simplistic market model that was incapable of accurately capturing scarcity pricing.

1.2 Emerging issues for energy-only markets

To date, the debate around the merit order effect has centred on the economic impacts of the merit order effect, particularly in regards to the effect on consumer electricity prices. Some argue that the increased wind and solar generation has lowered overall electricity price through the merit order effect, even when including the costs of any support mechanisms. Others argue that higher cost renewables technologies cannot “by definition” lower consumer costs (Felder 2011; Nelson, Reid, and McNeill 2014).

In Germany, the original Sensfuß, Ragwitz, and Genoese (2008) study estimated that the savings from the merit order effect from renewable generation in 2006 were about €5 billion, while the money spent on feed-in tariffs was €5.69 billion. This resulted in a net total cost of €0.69 billion for 52 TWh of renewable electricity. This electricity would have otherwise had a wholesale market value of €2.5 billion, representing a net saving to consumers. Munksgaard and Morthorst (2008), found that that whilst electricity consumers have to pay a subsidy to wind-power producers, the subsidy is to some extent compensated by reduced market prices originating from the low marginal production costs of wind power. Sáenz de Miera, Río González, and Vizcaíno (2008) also argued that the wholesale price reduction is greater than the increase in the costs for the consumers, resulting in a net reduction in the retail electricity price results, and a wealth transfer from generators to consumers. In Australia, McConnell et al. (2013) argued that the merit order effect may offset some or all of the costs associated with supporting solar.

Others, for example Rathmann (2007), argue that renewable energy support can only reduce electricity prices in situations where competition is strong. Sensfuß, Ragwitz, and Genoese (2008) points out that the competitiveness of the electricity supply system determines the extent to which any savings on the wholesale market are passed through to consumers⁷. Since electricity markets are characterised by oligopolistic behaviour, Traber and Kemfert (2009) conclude that:

“market power shifts the burden of the [Feed in Tariff] from the producers to the consumers, counteracting a theoretically possible price reduction on the consumer side under perfect competition”.

Competition issues aside, Nelson, Reid, and McNeill (2014), Nelson, Simshauser, and Nelson (2012) and Felder (2011) argue that any ‘out-of-market’ investment in capacity must lead to higher overall electricity prices. Renewable energy generation that requires additional ‘out-of-market’ policy support is, by definition, more expensive than the incumbent system and therefore must lead to higher overall electricity prices. This additional support effectively shields new renewable entrants from the ‘capacity cycle’ and the associated market price signal, which would lead to efficient investment decisions (Nelson, Reid, and McNeill 2014; Felder 2011). The merit-order effect is thus argued to be a wealth transfer from incumbent producers to consumers and new renewable generators, and not an increase in welfare.

These arguments may be true, but only in the context of the assumptions under which they are made. Any such assessment of the efficient system’s costs and welfare effects depend on what the ‘optimal’ system is assumed to be. In the context of global commitments to limit climate change, there is a strong argument that any such assessment should incorporate the need to rapidly decrease emissions. Absenting a cost of carbon from such analysis implicitly socialises the carbon cost. If the incumbent energy generation system truly internalised these costs, renewable energy would emerge as a more competitive technology. Should this result in an unsubsidised entry of a lower cost technology into the market, an associated improvement in welfare would be expected. Indeed as Nelson, Simshauser, and Nelson (2012) themselves point out:

“If a merit order effect occurred due to natural market disruption events such as the

⁷Different competition metrics are explored and used to assess the Australian Market in section 2.3.3

entry of a new renewable or low emission technology with lower marginal running costs and lower total costs than incumbent generators, it would produce an unambiguous improvement in welfare.” p.17

These arguments are important to trace in the context of understanding the effects and evolution of energy policies aimed at increasing renewable generation capacity. Indeed how these arguments play out may have a significant impact on the development of the renewable industry and energy sector more generally (Haines and McConnell 2013).

Much of the discussion of consumer cost is largely rooted in the short to medium-term effects, and often fails to consider the longer term implications, and questions around market design. This includes questions around the longer term cost, and the degree to which the effect is transitory, but also questions about how it affects future investment decisions (renewable or otherwise). In the absolute extreme, it may even expose the current electricity supply industry to systemic failure (Steed and Laybutt 2011; Nelson, Reid, and McNeill 2014). The next section reviews some of these emerging issues.

1.2.1 Resource adequacy and the “missing money” problem

A long standing debate concerning energy only markets is the ‘Resource adequacy problem’, term used to describe the potential for insufficient generating capacity relative to system demand (Simshauser 2010a). It is directly related to the ‘*missing money*’ problem, first identified by (Cramton and Stoft 2006, page 8):

‘The central problem, labelled “missing money”, is that, when generating capacity is adequate, electricity prices are too low to pay for adequate capacity.’

Cramton and Ockenfels (2012) key argument is that for long periods, energy-only markets may set prices that are insufficient to compensate asset owners for both fixed (capital) and variable (predominantly fuel) costs. In turn, generation capacity is inadequate and the market fails to reliably provide electricity.

There is continued debate about whether this issue is real, independent of the expansion of renewable generation (Edenhofer et al. 2013). In Australia, it has been suggested that average

wholesale prices have been insufficient for many plants to recover long-run marginal costs. For example, Simshauser (2010b) and Nelson, Reid, and McNeill (2014) suggest that many gas generators commissioned after 2005 would have been bankrupted had they not been vertically integrated. Steed and Laybutt (2011) argue that for energy-only markets to remunerate generators, the grid would virtually have to be at the edge of collapse, which is politically unpalatable ⁸.

Energy-only markets are predicated on the need for scarcity events and extreme prices to incentivize capital investment. In an efficient equilibrium, the resulting scarcity rents earned in such events are needed to, and would, cover the fixed capital and operating costs of all resources, which is consistent with perfect competition and marginal cost pricing (Cramton and Ockenfels 2012, page 118).

A variety of approaches have been proposed to deal with this problem, including (controversially) the introduction of capacity payments. In Australia, Nelson, Reid, and McNeill (2014) suggest design of the structure of the NEM requires examination by policy makers. Whilst the ‘missing money’ problem is not due to renewable energy, the more extreme and volatile prices of a high penetration renewable market may exacerbate the issue, as discussed further in the next section (see Edenhofer et al. 2013 for a greater review of this issue).

1.2.2 The emergence of new technologies

The emergence of new technologies draws attention to caveats for the capacity cycle and energy-only markets. While nice in theory, the underlying concept is based on an essentially steady growing demand, and constant technology development. This implies like for like replacement and on common timescales (4-5 years).

In practice, the rapid rise of renewables means markets are now contending with new technologies with dramatically different characteristics, alongside the unscheduled and unplanned exit of exiting capacity. The cost reductions realised by renewable energy technologies over the past five years alone are remarkable and continue to drive rapid deployment of renewable capacity (IRENA 2019) (see figure 1.7).

⁸This argument was in fact used by generators in Australia to lobby for the vertical integration that supposedly prevented the aforementioned potential bankruptcies.

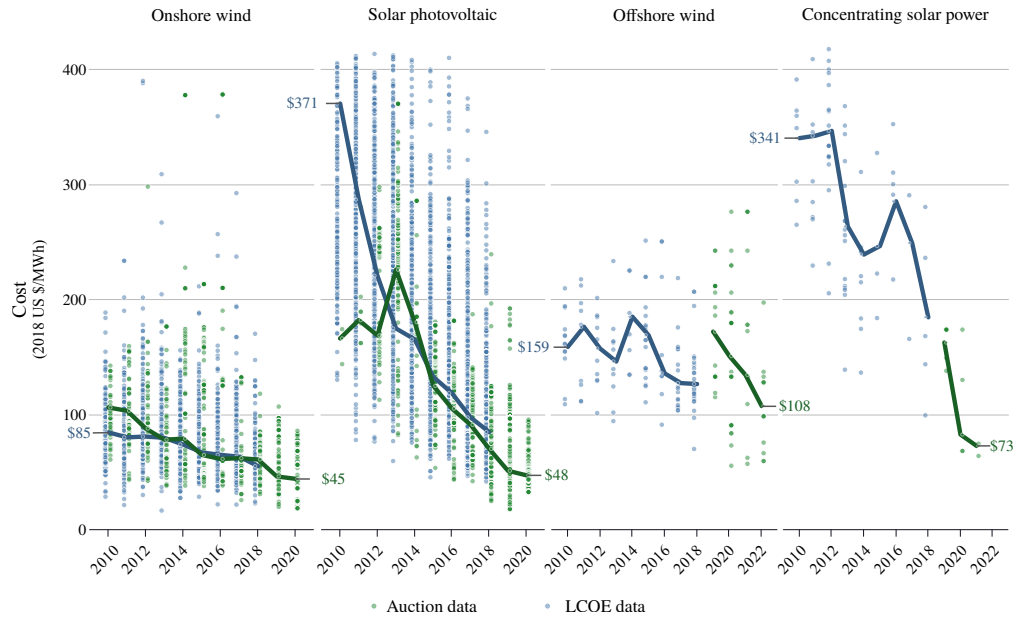


Figure 1.7: Cost and auction results for solar PV, onshore and offshore wind, and CSP projects (global weighted average values) [data source: IRENA (2019)].

Whilst averages prices can be expected to decrease in the long term with increasing penetration of lower cost renewable generation, it also increases volatility and has shorter term dynamic effects (Edenhofer et al. 2013). This is likely to present ongoing challenges to both the efficient functioning of energy-only markets and future investment in renewable energy.

As identified in Edenhofer et al. (2013), some commentators are concerned that short-run marginal cost pricing is not an appropriate design for future markets with a large proportion of zero marginal cost renewable energy. For example, a strong merit order effect naturally discourages further investment. Such an effect was identified by Leprich (2012) who argue that further investment in new technologies will be self limiting once the average price falls below long-run average costs. Similar arguments were made by Agora Energiewende (2013).

However, this is not *necessarily* a problem, as it disregards the dynamic response of markets (Edenhofer et al. 2013). It is argued that because lower average prices will normally lead to reductions in capacity through exits, the market should self balance towards an ‘efficient’ capacity level (Stoft 2002). This raises questions about the form that any reduction in capacity might take (e.g. induced closures of peak generation, fossil generation or renewable generation), as well as questions in energy security and reliability of supply, and how new capacity (renewable or

otherwise) will be financed.

Either way, a renewable dominated system is widely expected to increase price volatility. An increase in volatility accompanied by a decrease in average wholesale price may create additional problems, for example by exacerbating the “missing money problem”. The higher frequency and reliance on scarcity events to recover fixed costs means that markets with a high proportion of renewable generation might be particularly sensitive to the “missing money problem”. Since any investment in such a scenario would be expected to command higher risk premiums than might otherwise be the case, it could discourage sufficient investment to ensure adequate capacity (Joskow 2006a).

Variable renewables are of course only part of the story. Balancing capacity is also required. Due to its high flexibility, gas is often considered to be an ideal partner for variable renewable generation (Holz and Von Hirschhausen 2013). Electricity storage technologies and demand response (PPA) can also provide peak demand capacity, grid reliability and assist the integration of renewable energy sources (Dunn, Kamath, and Tarascon 2011). Large-scale electricity storage and PPA is an alternative option to effectively balance the power system, as variable renewable generation continues to expand (Knopf et al. 2013). In Australia, the market operator undertook a study exploring an Australian Market powered entirely by renewable energy. In this study, energy storage was described as being central to providing the flexibility and balancing services currently provided by fossil fuel generators (AEMO 2013a).

Storage technologies in particular would be expected to become more viable as a result of increased renewable generation. However, all technologies (emerging or existing) required to balance variable renewable energy generation will be acutely exposed to market price volatility, and thus risk premiums as described above. Understanding the effects of dynamic pricing and how the capacity cycle and pricing system interacts with these emerging and retiring technologies is critically important to efficient decarbonisation of the electricity sector. A particular issue arises in the balancing of the variable nature of renewable generation by storage technologies. In an energy-only market the arbitrage opportunity exists only because of inherent price volatility. Therefore, a key question is whether energy-only markets with a high proportion of largely renewable generation markets can support sufficient storage capacity to simultaneously stabilise the grid and provide the economic returns to incentivise such investment.

1.3 Summary

Critical questions remain about the future impact of the merit order effect, and how electricity markets in their current formulation will respond. How transient the merit order effect is, and how existing thermal generators might respond and new flexible generation investment occurs are critical questions. This includes how old generation might exit the market, and the related security and reliability concerns (Edenhofer et al. 2013; Nelson, Reid, and McNeill 2014). Questions also remain about how renewable energy will continue to be financed and expand in an energy-only market, with increased volatility and lower electricity prices (Hirth 2013; Agora Energiewende 2013; Leprich 2012).

An interesting possibility is that a rather different type of capacity cycle may emerge that may dictate the near to mid-term future (see figure 1.8). As renewable energy is added to the grid and prices are depressed, incumbent generators maybe forced to exit the market in an unscheduled or unexpected manner. Unlike building a new power plant, which takes years and is well signalled to the market, plants may exit with little notice, resulting in a rapid rebound of

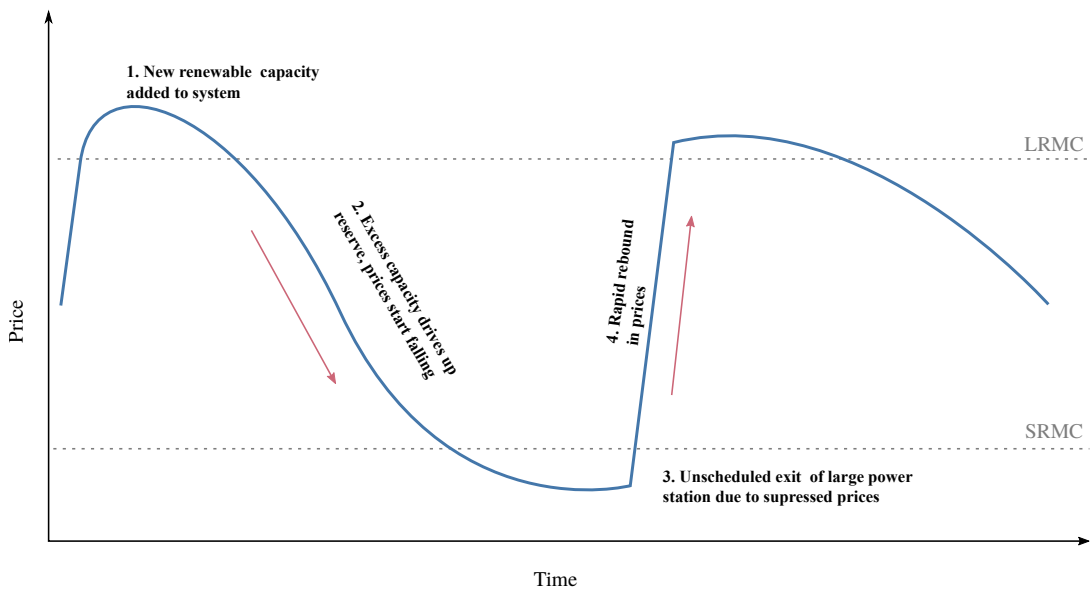


Figure 1.8: The capacity cycle may be taking on a new form, with unscheduled removal of large amounts of capacity in short periods of time. A saw tooth pattern may occur, where the incremental addition of renewable energy eventually forces the exit of a single large generator, at short notice. Over time, as technology costs decrease, the top of the saw tooth might be expected to decline.

prices and tightening of the reserve margin. In addition, the plants that exit the market are likely to be large in size, relative to the incremental additions of smaller renewable energy projects. This may ultimately test the capacity cycle approach.

This thesis aims to provide further insight into how energy-only markets might evolve with high penetrations of renewables, in the context of a transition to a lower carbon energy system. Understanding such issues is of critical importance in the context of the need to rapidly decarbonising the sector. This work aims to contribute the existing literature on the impact of new technologies on the electricity systems, and dominant market constructs by investigating the National Electricity Market in Australia. Australia, and in particular the South Australian market region, provides an excellent system to study with respect to these questions. As is illustrated in the next chapter, the National Electricity Market in Australia is a very pure implementation of the energy-only market design, and the South Australian market region, where the energy transition is underway, has many lessons to reveal.

Chapter 2

Context

This chapter provides an overview of key characteristics of the National Electricity Market in Australia, with a special focus on the South Australian Market region. This chapter is structured as follows: firstly, I describe the key elements of the National Electricity Market (NEM), including market design elements, contracting practices, price dynamics and renewable energy support schemes¹. In the second section, I drill down into the South Australia region and describe its physical characteristics and explore some of the key dynamics effecting both wholesale prices both within the South Australian market region more broadly across the NEM. The chapter concludes by drawing out open questions and specific avenues for further analysis.

2.1 The Australian National Electricity Market

The NEM is a zonal market with five interconnected regions² supplying approximately 90% of Australia's grid supplied electricity (Productivity Commission 2013). Almost 300 large³ generators are physically linked across the NEM, delivering 203 TWh of energy to almost 10 million customers in the FY18⁴(AER 2018). The electricity demand profile and characteristics vary

¹See appendix A for a brief history of the development of the National Electricity Market

²The NEM comprises five interconnected regions including the mainland states of South Australia (SA), Victoria (VIC), New South Wales (NSW) and Queensland (QLD) as well as the island state of Tasmania (TAS).

³Generators with nameplate capacity of 5MW or greater are required to register as a 'Market Generator', and are considered 'large' (and distinct from Small-scale non-scheduled PV generation).

⁴In Australia, the financial year ends on the 30th June. Here I refer to financial years using the two last digits of the year in which it ends. Thus FY16 refers to the period 2015/07/01 through 2016/06/30.

substantially across each region. Like other electricity markets around the world, demand in the NEM is highly variable and is strongly affected by temperature.

The NEM is classed as an *energy-only gross pool* market was often held up as a good example of an energy-only market (Pfeifenberger, Spees, and Schumacher 2009). In this design, there is no capacity market (energy-only) and all electricity is traded through a central pool (gross pool). As such, generators only receive revenue for the electricity output sent to market, typically measured in units of megawatt hours (MWh). This is distinct from some systems that have parallel markets for energy *and* capacity, such as the system that operates in Western Australia.

The dispatch process is centrally managed by the Australian Market Energy Operator (AEMO), with wholesale Regional Reference Prices (RRP) calculated for each region. These RRP's are the settlement price for all generators and loads within the region. Prices are formed with a uniform price auction mechanism, which clears on a five minute 'dispatch interval' and is settled on a half hourly 'trading interval' basis⁵

2.1.1 The Market Price Cap, reliability and volatility

Most energy-only markets have a price cap at a value many times higher than the short-run marginal cost of production of even the most expensive generators (As discussed in section 1.1). At \$14,500/MWh, the NEM's current *market price cap* (MPC) is one of the highest in the world⁶ and is approximately 300 times the historical volume weighted average price. The market also has a floor price of -\$1000/MWh. The price cap is derived from the *reliability standard*, which is related to, but not the same as, the Value of Lost Load (VoLL) as is commonly used in other markets (Sioshansi 2008).

The *reliability standard* is the metric used to assess reliability in the NEM and is a percentage value that reflects the *expected unserved energy* (expected USE) in a given year. Unserved energy is energy that is not supplied customers as a result of inadequate generation capacity or inter-regional interconnector constraints⁷. If the *expected USE* is less than the reliability standard for a given year, then the system is said to be *reliable*⁸. The reliability standard is set by the

⁵Wholesale or *spot* prices, are set on a 30-minute settlement period basis as the average of six 5-minute dispatch interval prices. They are distinct from the contract prices discussed in the next section

⁶The NEM price cap has increased over time, from \$10,000 prior to 2010, to \$14,500 today

⁷*Intra*-regional constraints do not contribute to USE.

⁸This differs from some international markets that often use different metrics such as the Loss of Load

Australia Energy Market Commission’s (AEMC) reliability panel and is currently 0.002%⁹.

In theory, this cap reflects the wholesale price necessary for the last generator required to meet the NEM’s *reliability standard* to be financially viable. This is in contrast to other approaches that explicitly price the Value of Lost Load¹⁰. Alternatively, the price cap should be high enough that average spot prices “*provide a revenue stream that matches total costs (both fixed and variable) of the optimal fleet of efficient generators*” (Nelson, Reid, and McNeill 2014). In this context, the ‘optimal fleet of efficient generators’ is the least cost mix of plant that ensures the *reliability standard* is met.

A direct consequence of this design is that it is not uncommon for prices to reach the price cap during periods of scarcity. Scarcity conditions arise when all capacity available on the system is needed to supply energy or ancillary services to balance supply and demands (Joskow 2008). Under normal operating conditions, prices typically reflect the short run marginal cost of production. However, as customer demand increases and available capacity becomes scarce, spot prices can rise dramatically (Simshauser 2010a), reflecting exercise of market power. Indeed price caps are built on the expectation that generators will withhold supply under scarcity conditions (Hogan 2012). Prices may increase more than 3000-fold from a low-to-average price (historically \$50/Mwh) to \$14,500/MWh in the space of half an hour. As such, the NEM is one of the most volatile commodity markets in the world (Nelson, Reid, and McNeill 2014; Steed and Laybutt 2011). It is of note that Simshauser (2010b) have suggested the NEM price cap is too low and should be increased to \$24,5000/MWh to allow generators to recover long-run marginal costs.

As discussed by Riesz (2012) in a future with 100% renewable energy penetrations, an electricity market could well have a price close to zero for the majority of the time (assuming electricity markets remain competitive). Riesz (2012) suggests in such circumstances generators would need to recover an increased proportion of fixed costs during scarcity events. The market price cap needed to offset the reduction in average market prices in a 100% renewable energy system is estimated be between approximately \$60,000/MWh to \$100,000/MWh (Riesz 2012).

Probability (LoLP)

⁹The panel has recently published a draft report as part of the 2018 *Reliability standard and settings review*. Interestingly, given the current focus on reliability, the Panel has not recommended any changes to the previously mentioned reliability settings and standards, See page 1, AEMC (2018), *Reliability standard and settings review* for further details

¹⁰However the reliability settings are *informed* by the Value of Customer Reliability (VCR), which is comparable to the Value of Lost Load

Wholesale spot prices vary between regions and over time in response to a range of other factors. These can be short term factors related to daily supply and demand patterns, or longer term patterns related to the capacity cycle and investment decisions. The regional differences in load and generation capacities, in combination with network constraints between the regions, translate into differences in regional prices and price volatility. Figure 2.1 illustrates some of the longer duration dynamics where, for example, wholesale prices in FY13 and FY14 were elevated because carbon pricing was implemented at the generation level. Similarly, in FY07, during the later stages of the Millennium Drought, prices rose steeply as reduced output from hydro and some thermal power stations significantly tightened supply.

This price pattern shown in figure 2.2 also provides evidence of the impact of the “capacity cycle” in the NEM (Nelson, Reid, and McNeill 2014), showing how peaks in commissioning of new investment in 2000, 2007 and 2008, were followed by falling prices

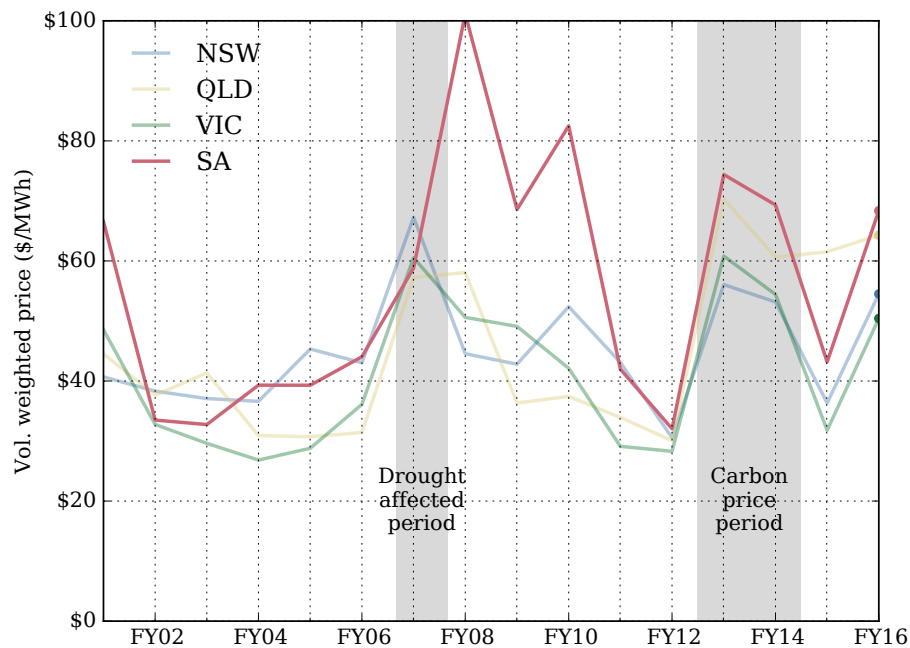


Figure 2.1: Annual volume weighted prices by financial year across the four mainland regions that form part of the National Electricity Market (NEM). Note that prices vary by region and across time, with South Australia typically at the upper end of the regional range, especially in the period between FY08 and FY10. In FY13 and FY14, carbon pricing applied at the generation level elevated wholesale prices by an average of about \$20/MWh¹¹. Prices across all regions were elevated in FY07, at the height of the Millennium Drought, due to constrained output from hydro power and some thermal plant.

¹¹Only \$14/MWh were added to SA wholesale prices due to the lower carbon intensity of the fleet.

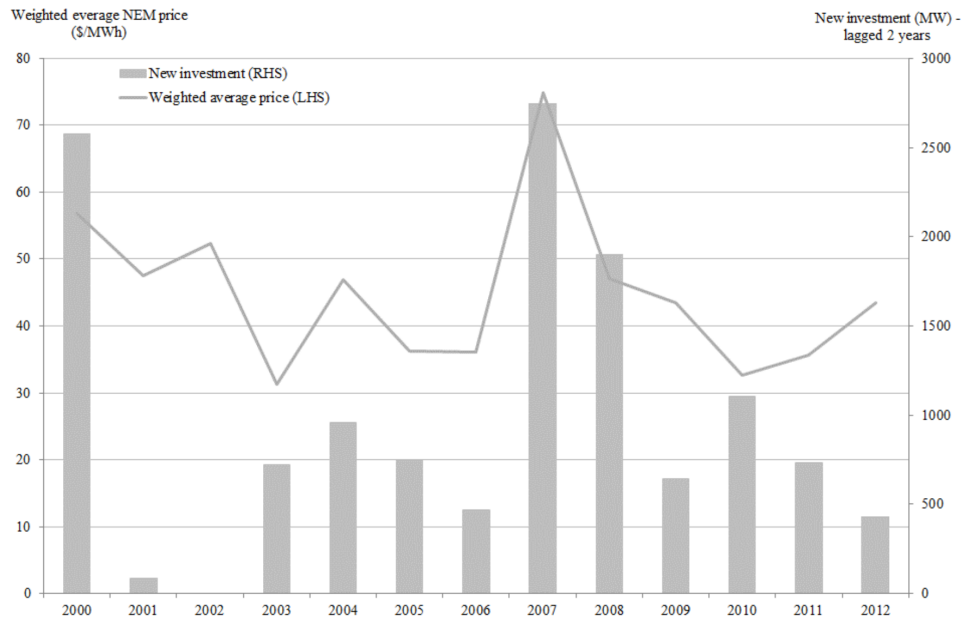


Figure 2.2: Weighted-average NEM wholesale electricity prices and new investment: the Australian capacity cycle, [source: Nelson, Reid, and McNeill (2014)].

For many years reserve margins in the NEM have been consistently higher than 15%, and in FY15 were well above this at approximately 37%. It's also worth noting that NEM reforms happened during a period of high reserves. This was reflected in very low wholesale prices (when adjusted in real terms) towards the beginning of the NEM, and more recently is a function of increasing renewable generation supported by a certificate scheme (the Renewable Energy Target) and 7 years of declining demand (Sandiford et al. 2015). While renewable energy is not always available, it still increases reserves at a level determined by the operator, as a function of historical performance in periods of scarcity.

Since FY15, a significant re-balancing has tightened reserve margins causing wholesale prices to track well above LRMC. This re-balancing is due in part to the exit of several large thermal coal plants and in part to a significant increase in demand accompanying the development of an LNG export industry in the QLD region.

2.1.2 Hedging and contracting

The extreme range in wholesale pricing and the consequent price volatility exposes market participants to significant risk. Persistent low prices reduce generator earnings, potentially to levels below the long-run marginal cost of production. In contrast, frequent scarcity events can drive energy costs for exposed customers to unsustainable levels. Consequently, market participants use a variety of strategies to manage wholesale pricing risks, including vertical integration, hedging on the *Exchange Traded Future* (ETF) markets and *Over-The-Counter* (OTC) bi-lateral contracts.

The dominant hedging strategy in the NEM is vertical integration. Generally, this involves the re-integration of generation and retail business into single entities (so-called “gentailers”), effectively unwinding the structural separation that occurred during the reforms of the late 90s. This allowed internal hedging, with the retail component of business the counter party to the wholesale component.

The most frequently hedging strategy outside of vertical integration is short to medium-term bilateral contracts, with market participants maintaining contract portfolios that reflect the uncertainty of future prices (Anderson, Hu, and Winchester 2007; Steed and Laybutt 2011). For example one year out, participants may want to be fully (100%) contracted, two years out 60-70% contracted, three years out 20-30% contracted, and at four years out 5-10% contracted (Anderson, Hu, and Winchester 2007). Figure 2.3 sets out a typical forward contract position of a retailer, which mirrors that of the generator (Steed and Laybutt 2011)

In FY15, on a NEM-wide basis, 84% of hedging contracts were traded as futures (ETFs) through the Australian Stock Exchange (ASX) with the remainder traded as bilateral OTCs (AER 2015). The volume of trades is a measure of *market liquidity*, and was 3.0 times the native demand in FY15, down from 3.6 in FY14 (AFMA 2015). The liquidity varies across regions. In FY15, the most actively traded state in the ETF market was Queensland at 37% of volume, followed by New South Wales at 35%, Victoria at 26% and South Australia at 2% (AFMA 2015). The volume of futures trading in South Australia is the lowest relative to underlying demand and wholesale market turnover¹².

¹²The illiquid nature of the futures markets is reflective of the fact the underlying markets are not perfectly competitive (See Anderson, Hu, and Winchester 2007)

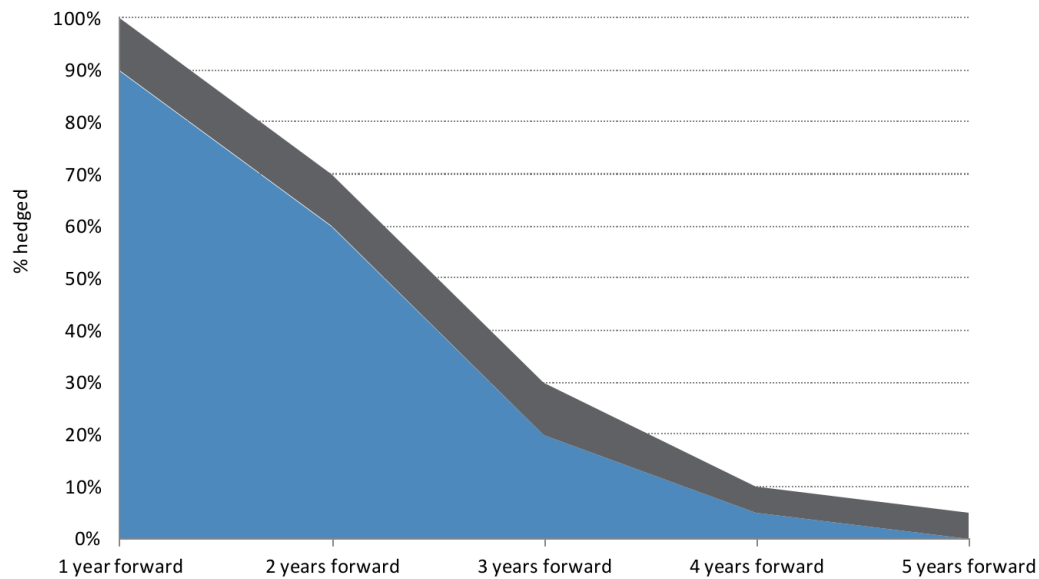


Figure 2.3: Typical forward contract coverage for generators (black) and retailers (blue) in the NEM, source: Steed and Laybutt (2011).

As described in detail by AEMC (2012) and Productivity Commission (2013, appendix C), there are three standard contract types¹³:

- *Base load futures* covering a full 24 hour period on each day over a specified calendar quarter.
- *Peak load futures* covering the period from 7:00am to 10:00pm on working weekdays in a quarter.
- *\$300 cap futures* that allow retailers and other consumers to manage the risk of high wholesale prices in a similar manner to an OTC cap with a strike price of \$300/MWh.

¹³The baseload and peak contracts are ‘swap contracts’, while the \$300 ‘cap’ are effectively ‘options contracts’ as applied in other commodity markets.

Swap contracts

Baseload and peak futures allow both generators and consumers to manage wholesale price volatility in a similar manner to swap contracts. With swap contracts, the counter-parties effectively ‘swap’ the payment/receipt of the NEM spot price for the payment/receipt of the contracted strike price (AEMC 2012, page 11). Swaps are also known as *contracts for differences*.

Cap contracts

‘Cap contracts’ are a common hedging product used in the electricity market, which are effectively a type of option contract. They typically involve a large electricity consumer (for example a retailer) that wishes to hedge its exposure to the extreme price spikes (for example, when the price rises to market price cap)¹⁴. The contract counter party is typically a generator (and in particular a peaking generator, able to respond rapidly to market conditions) seeking a more stable and bankable income stream than provided by infrequent and inherently unpredictable wholesale spot price spikes.

In these arrangements, the generators are essentially providing insurance to the consumer that purchases the contract. The generator agrees to re-reimburse the consumer for any electricity prices above \$300 dollars (the maximum price the consumer has to pay is effectively \$300 dollars). In return for this, the consumer pays a fixed rate (like a premium) to the generator providing the generator receives a steady income stream. The AEMC describes cap contracts as follows:

The parties agree on a strike price for the cap. If the spot price exceeds this strike price, the seller of the cap (usually a generator) must pay the difference to the buyer of the cap (usually a retailer). A common strike price for a cap contract is \$300/MWh. In return, the buyer of the cap will pay the seller a fee, which provides the generator with an extra source of revenue. Buying such a cap helps protect the retailer from high spot prices.

(AEMC 2012, Table 2.1, page 10)

¹⁴Some participants may also use cap contracts to hedge a large plant against the occurrence of unplanned outage during a high price

Figure 2.4 illustrate how cap contracts operate, and the financial transfers that result. In this example, the price spikes to \$5000. A generator that is selling into the market will receive \$5000 from AEMO, while a consumer purchasing from AEMO will pay \$5000. If however they are contracted to each other with a cap contract, the generator makes payments of \$4700 back to the retailer. In the case, the retailer would only have effectively paid \$300, and the generator would have only received \$300 dollars. However, the generator will also have a fixed payment (the premium) in addition to this for providing this insurance to the consumer.

Because payments are made to the contracted generator for all trading intervals of the year, even if the generator is not dispatching, such hedging arrangements effectively signals the value of capacity in an energy-only market. Such arrangements provide a strong incentive to make capacity available and able to respond to price spikes. If a contracted generator is unable to respond, it is effectively penalised because the payments to the retailer (for example \$4700 in the example above) cannot be offset by revenue from the market operator.

Figure 2.5 illustrates how a retailer might manage the risk associated with their customer load using a variety of these products. Typically, retailers might contract 90-100% of the their load one year in advance, declining to 60%-70% two years out. As such, exposure to wholesale market prices is typically limited. However, wholesale prices effect contract prices, and the extent of coverage varies over time.

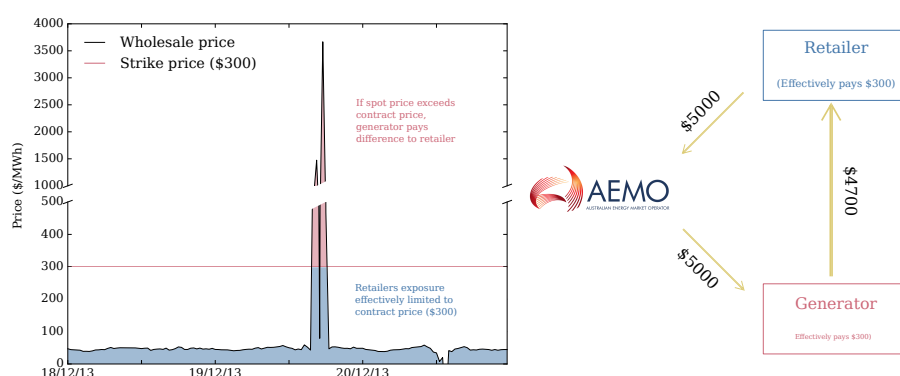


Figure 2.4: Illustrative cap contract (right), with a strike price of \$300. The contract payment limits exposure of the buyer (typically a retailer, or large energy consumer), to price spikes exceeding the strike price. The financial transfers (right) for a cap contract with a strike price of \$300 and a wholesale spot price of \$5000/MWh are shown at the right.

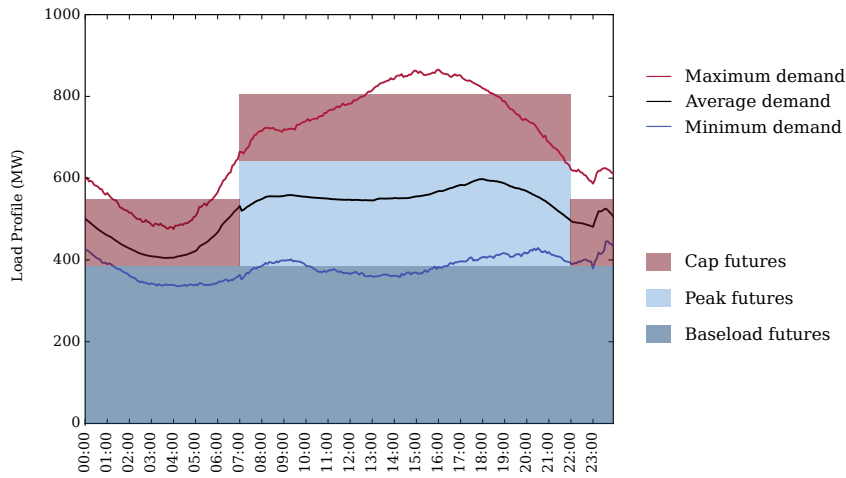


Figure 2.5: Illustrative risk management approach, using a combination of contract types. The lines represent a hypothetical load profile, and the shaded areas represent the coverage provided by different hedging products in a hypothetical contract scenario. By combining the three standard contract types generators can ensure a more certain revenue stream while retailers can hedge exposure to extreme price spikes.

2.1.3 The value of energy and capacity

The way participants use these hedging strategies provides an insight into the way the market values *capacity* as opposed to *energy*. For a fully hedged participant, the cost of energy is expressed as the volume weighted price subject to a price ceiling at the strike price, which I term the *hedged volume weighted price*. Contrawise, the cost of capacity can be expressed in terms of the number of scarcity events or price increments in excess of the strike price¹⁵.

Figure 2.6 compares, in the top panel, the number of scarcity events (i.e., a measure of the way the market values capacity) and, in the bottom panel, the hedged volume weighted price with a ceiling of \$300/MWh, across the four mainland NEM regions. The bottom panel shows that while the market has tended to value energy in South Australia slightly higher than in other regions, the values broadly align across all regions. This contrasts significantly with Figure 2.1 which shows more dramatic price divergence between the regions when scarcity events are included in the price, especially in FY08 through FY10. The top panel in Figure 2.6 illustrates that since FY12 the way the market values capacity in South Australia has been comparable

¹⁵In practice, the cost of cap contracts will track the frequency or expected frequency of scarcity events.

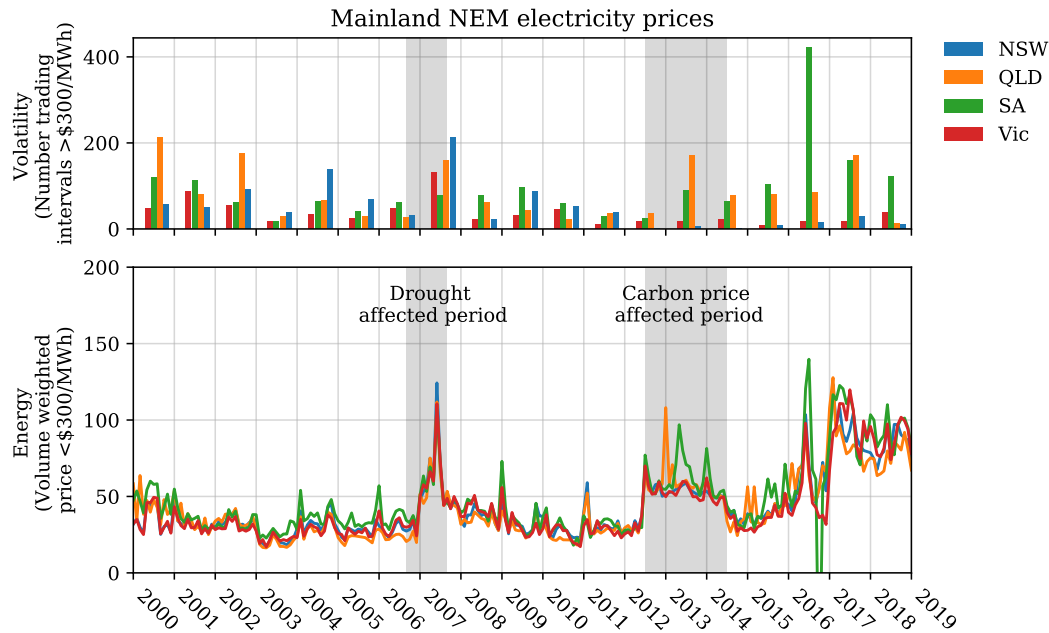


Figure 2.6: Wholesale prices for the four main NEM regions since the beginning of FY01. Top panel shows the number of settlement price events above \$300/MWh by financial year. Bottom panel shows the monthly hedged volume weighted price with prices capped at \$300/MWh. Refer to Figure 1 for a comparison with the unhedged volume weighted prices

to, and sometimes lower than, Queensland, but much higher than either New South Wales and Victoria. Note that FY11 and FY12 were characterised by very low scarcity across all regions, especially in comparison to the preceding drought-affected period.

Figure 2.7 shows both the number of scarcity events (prices at \$300/MWh or higher) and the hedged volume weighted price in South Australia has diverged significantly from the other regions since May, 2016. The 236 settlement period scarcity events in July 2016 in South Australia set an all-time monthly record for the NEM¹⁶. The divergence followed the closure of the Northern Power Station on May 9th. The scale of the divergence is made apparent by the fact that the number of scarcity events in South Australia in July 2016 exceeded the total of 185 for the entire FY16 (Table 2.1).

¹⁶Other notable tallies for monthly settlement scarcity events include, in order: 228 in Tasmania in April 2016, 136 in Queensland in January 2013, 71 in South Australia in June 2016, 55 in South Australia in January 2009, and 47 in Queensland in February 2016

Table 2.1: Number of high price settlement period events in each of the four mainland NEM regions for financial years FY10 through FY16, and July 2016.

	>\$300				>\$1000			
	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2010	120	48	88	47	69	42	73	39
2011	39	37	23	13	31	22	16	10
2012	1	22	12	0	1	5	11	0
2013	2	168	89	30	0	47	71	18
2014	7	59	74	26	4	43	33	13
2015	1	106	49	1	1	90	37	0
2016	10	88	185	16	6	64	48	8
2017	39	176	431	18	18	94	122	2
2018	8	9	117	38	5	5	37	22
Total	227	713	1068	189	135	412	448	112

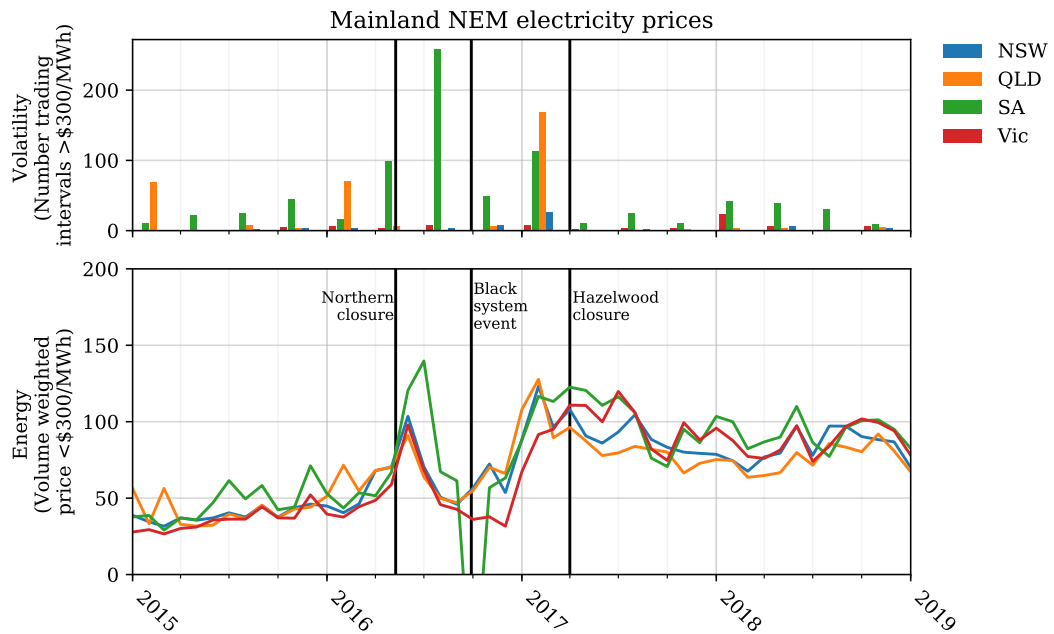


Figure 2.7: Monthly averaged prices for the four main NEM regions since the start of FY16. Top panel shows the number of scarcity events above \$300/MWh per month. Bottom panel shows the monthly volume weighted price, for prices below \$300/MWh. Note that the scarcity events are tallied by settlement periods (i.e. on the half hour trading period basis), and include many more 5-minute dispatch period scarcity events. For example, along with the 236 settlement scarcity events in South Australia in July 2016, there were also 1315 dispatch scarcity events.

2.1.4 Renewable energy support schemes

Australia has a poor record involving many failed policies to reduce emissions in the electricity sector, that will not be discussed further here. However, renewable energy support policies have remained relatively intact and effective in reducing emissions and will briefly be described.

In Australia, large-scale renewable energy is supported by the Large-scale Renewable Energy Target (LRET). Under the LRET scheme, retailers and other energy users are required to purchase Large-scale Generation Certificates (LGC) based on their energy consumption. LGC's are purchased from eligible generators, such as wind farms. LGC's provide eligible projects with a revenue stream additional to the market value of the dispatched power, thereby facilitating with their financing. The cost of the LGC's are passed on the consumers. Some large energy users are exempt, or partially exempt, from the LRET due to trade exposure.

Small-scale renewable energy systems such as rooftop solar photovoltaics (PV) are supported by the Small-scale Renewable Energy Scheme (SRES) and state based feed-in tariffs (FiT). The SRES is similar to the LRET in that retailers are obliged to purchase certificates. However unlike the LRET, the SRES payments are deemed upfront and function as a *capital cost subsidy*. In contrast, FiTs provide a revenue stream based on energy generated or exported to the grid.

In combination, these renewable energy support policies and falling technology costs have had a dramatic impact on the energy and investment landscape over the past decade. Figure 2.8 shows the dramatic expansion of renewable energy investment, and how renewable energy generation has expanded over time.

2.2 The South Australian market region

The South Australian market region is of particular interest, because it has undergone a dramatic change in supply mix over the last decade. As a relatively small market with a mean annual demand of between 1400-1600 MW energy generation needs were predominantly sourced from gas and brown coal power stations prior to 2005. Since then, over 2100 MW of wind capacity, 380 MW of utility solar¹⁷ and almost 1000MW of rooftop solar has has been installed. At the same time, 770 MW of brown coal capacity has exited the market. Considering in relation to the

¹⁷At the time of writing some of this capacity was still undergoing commissioning

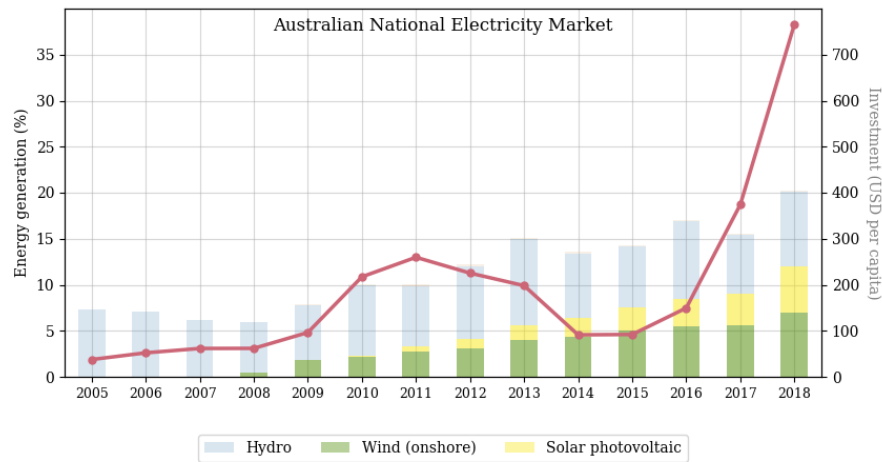


Figure 2.8: Renewable energy generation and investment in the NEM since 2005. The did in investment from 2014 is related to the uncertainty surrounding the LRET scheme, during the period of the Warburton review.

median annual demand in the region, which has remained roughly unchanged, these changes in generation mix are quite remarkable and have substantially reduced the state’s greenhouse gas emissions.

Following the closure of the 520 MW Northern power station, the South Australian market region wholesale price increased steeply to record highs, in early July 2016, leading to what soon became known as the *South Australian “energy crisis”*. Media attention at the time focused on the relationship between the high level of penetration of renewable energy and the extraordinary wholesale prices. Much of the reporting was framed in ideological terms - renewables are either ‘good’ or ‘bad’ - with little reference to quantitative analysis of the dynamics of the wholesale electricity market or movements in associated markets such as gas.

A subsequent “crisis” that soon followed a few months later somewhat eclipsed this supply crisis. On the 28th of September at approximately 4pm, South Australia experienced a ‘black system’ event, plunging the entire state in darkness for several hours. Approximately 850,000 South Australian customers lost electricity supply including mass market customers (for example households and small businesses) but also major industries, transport and other community services. Most electricity supply was restored within 8 hours, however the wholesale market in

SA was suspended for a total period of 13 days. The total cost of the black system event to South Australian business was estimated at \$367 million. The resulting media and political storm, and the subsequent responses have re-shaped Australia's electricity landscape.

The rest of this chapter explores the evolving dynamics in the electricity market in South Australia and how it is impacting wholesale prices. In particular, the remaining sections focus on the growth in renewable energy generation, the impact of a changing gas market and market power concentration and competition issues.

2.2.1 Demand

South Australia is the smallest of the four mainland NEM regions. Its annual electrical energy consumption for FY15 was 13,006 GWh (AEMO 2015b, Table 13) and increased to 13,421 GWh in FY16. The median annual demand in South Australia is typically between 1300 and 1400 MW.

Across all four mainland NEM regions the demand for electricity varies significantly on daily, weekly and seasonal time-frames. Across the NEM the annual peak in demand typically occurs in the afternoon or early evening in summer. The highest demand recorded in South Australia was 3402 MW on January 31st, 2011¹⁸.

Of all the NEM regions, South Australia has the 'peakiest' demand profile, and suffers the greatest seasonal variability, reflecting the relatively high proportion of load from domestic customers. In FY14 the ratio of maximum demand to minimum demand was 4.54. This compares with 2.72 for New South Wales, 2.22 for Queensland and 3.16 for Victoria. Daily fluctuations in South Australian demand can be as large as 250% (from trough to peak) on a single day¹⁹.

In the years prior to 2011, South Australian peak demand grew at an average annual rate of about 3.5%²⁰, but has not grown since. The peak in the summer of FY16 was some 13.3% below the record 2011 peak²¹. Figure 2.9 illustrates the annual demand characteristics for South Australia since FY06.

¹⁸On January 31st, 2011, the total of demand and non-scheduled generation in South Australia reached reached 3429.76 MW

¹⁹For example, on December 20th, 2009 demand increased from 1072 MW at 3am to 2674.77 MW at 5pm.

²⁰Peak demand in FY02 was 2499 MW compared to 3402 MW in FY11.

²¹The FY16 peak at 2948.38 MW, occurred on December 17th, 2015 just after 5pm. Then the total of demand and non-scheduled generation reached reached 3006.36 MW

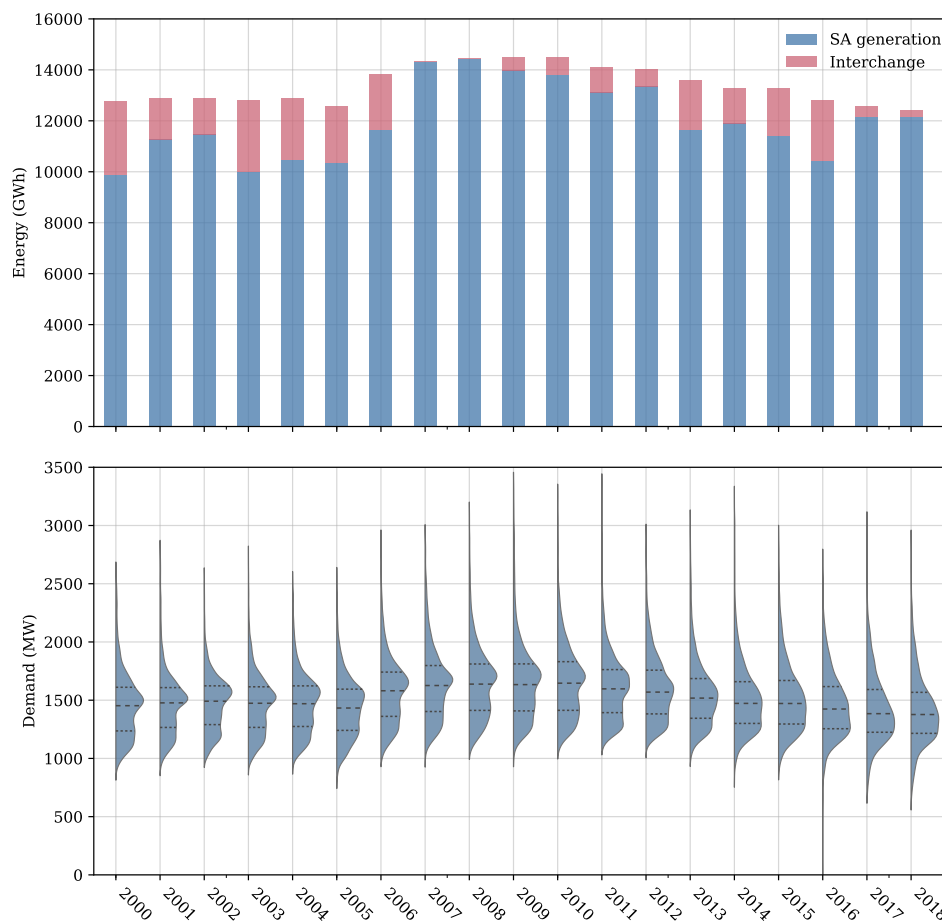


Figure 2.9: Annual consumption and demand in South Australia, FY06-FY18. Top panel shows the South Australian electrical energy consumption, local generation and net imports via the interconnectors (Heywood and Murraylink) into Victoria in GWh, with imports referenced by units on the right hand side. The bottom panel shows key characteristics of demand in terms of the annual minimum, median and maximum, all in MW by financial year.

2.2.2 Generation and interconnection

Historically, South Australian energy supply has been dominated by a roughly equal mix of gas and brown coal-fired power, but that has changed dramatically over the last decade (figure 2.11 and figure 2.10). The high proportion of gas has long distinguished South Australia from the

other mainland regions which are much more dominated by coal²². The generation capacity in South Australia currently includes approximately 660 MW of Combined Cycle Gas Turbine (CCGT) and 1280 MW of thermal (steam) gas. A further 770 MW of Open Cycle Gas Turbine (OCGT) capacity and 730MW of diesel generation²³ provides for peak power requirements. As outlined below, South Australian brown coal capacity declined from 770 MW to 530 MW in 2012 then to 0 in May 2016).

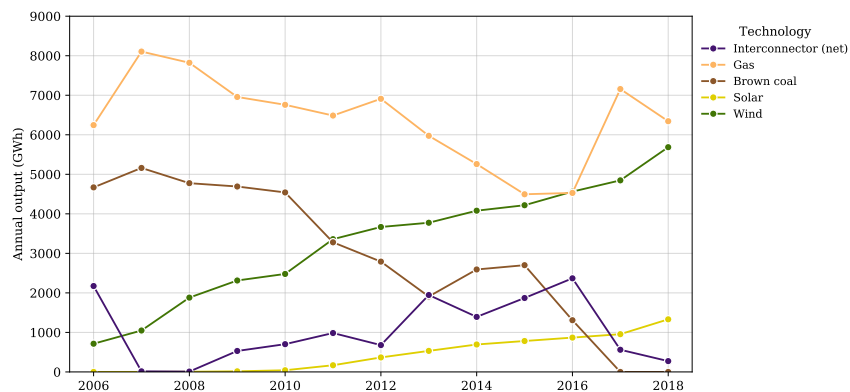


Figure 2.10: South Australian supply trends by generation fuel type in GWh by calendar year from 2006 to 2018. The three gas generation types are aggregated in this figure.

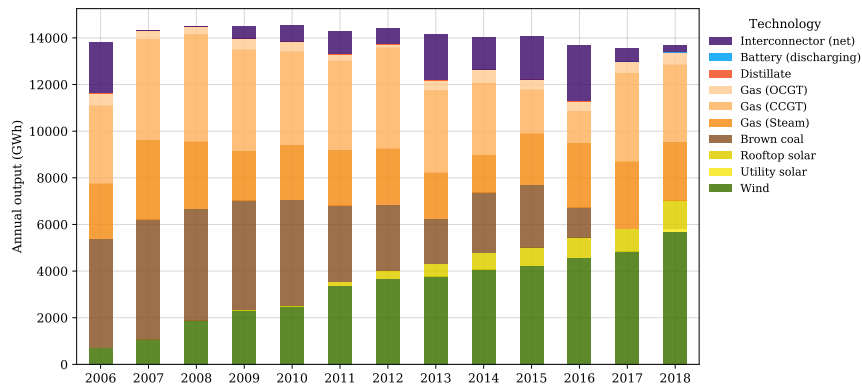


Figure 2.11: South Australian annual electricity supply by generation type in GWh by calendar year from 2006 to 2018. Interchange refers to the net energy import via exchange with Victoria.

²²In FY16, coal supplied 86.4% of New South Wales, 83.9% of Queensland and 86.3% of Victorian grid generation.

²³This includes 275MW of newly commissioned state owned generators, that were installed in response to the black system event.

Some 2100 MW of wind capacity will soon have been added to the South Australian generation system, largely in response to the national Renewable Energy Target (RET)²⁴. Consequently, in times of high wind and solar generation and low regional demand, renewable energy generation can well exceed South Australian demand, with excess production exported to Victoria. The *capacity factor* for South Australian wind output in FY16 was 33.5%. For calendar year 2018, some 41.3% of South Australia's electricity generation came from wind and solar.

South Australia is connected to the NEM via two transmissions links into Victoria. The Heywood interconnector has a rated capacity of 650 MW²⁵. The Murraylink interconnector has a rated capacity of 220 MW. As indicated in figure 2.11, South Australia is a net-importer of energy.

Brown coal withdrawal

As of May 2016, South Australia has had no remaining local coal generation. The 240 MW Playford B Power Station was mothballed in 2012. For a few years prior to mothballing it was primarily operated in the summer. Along with the 530 MW Northern Power Station, Playford B was permanently closed on May 9th 2016 (see figure 2.12). Prior to closure, Northern's capacity was equal to approximately 15% of South Australian peak demand, and 40% of median demand, although in the last few years of its operation, Northern was generating at capacity factor around only 56%. In terms of a *regional basis size*, expressed as the ratio of power plant capacity to regional demand, Northern was one of the largest stations dispatching in the NEM, with a regional basis size comparable to the 2200 MW Loy Yang A Power Station in Victoria²⁶. Figures 2.11, 2.10 and 2.12 show the change in supply and capacity in South Australia as a result the progressive withdrawal of brown coal generators.

Of particular interest in this chapter are the changes in supply that immediately followed the closure of Northern. Figure 2.13 shows the change in dispatch profiles for a week in July one year apart. The winter months following closure were also impacted by constraints on the Heywood interconnector into Victoria, due to upgrade work²⁷.

²⁴At the time of writing, the 212MW Lincoln Gap Wind Farm was still under construction

²⁵ElectraNet completed upgrades to the Heywood interconnector in July 2016, see ElectraNet Fact-sheet: Heywood Interconnector

²⁶See table B.1 in appendix B.1 for a comparison of different coal generators in the NEM

²⁷This period is examined in closer detail in section 2.3.3

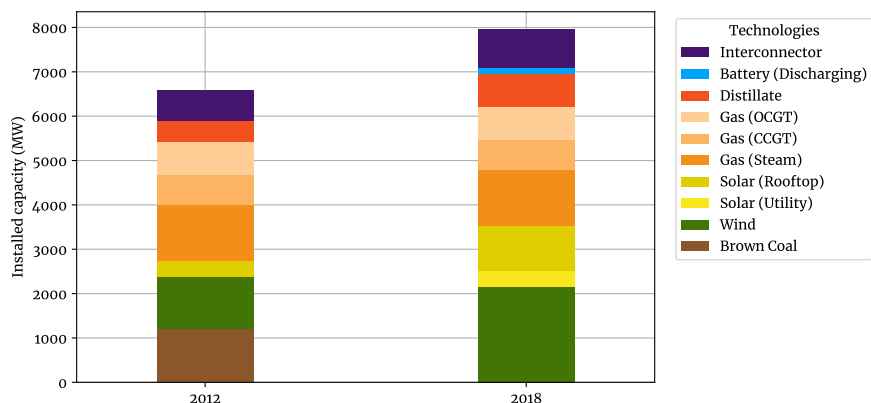


Figure 2.12: South Australian capacity by generation type in MW, as of end of 2012 (left) and end of 2019 (right). During this period there has been a substantial change in the installed capacity. In addition, the Heywood interconnector was upgraded.

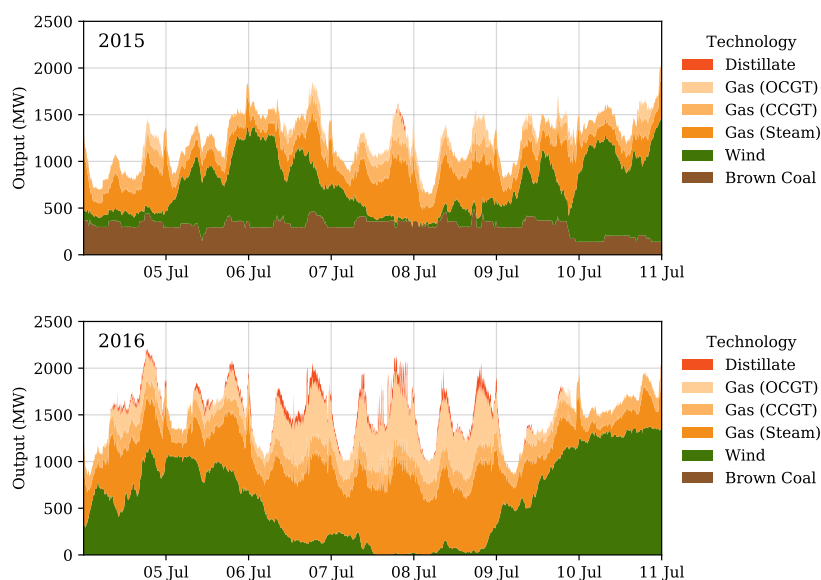


Figure 2.13: Illustrative South Australian dispatch profiles for the week 4th through 11th July, in 2015 (top panel) and 2016 (bottom panel). Brown is coal dispatch, red is liquid fuels, orange is gas and green is wind, in MW. The events of July 7th, 2016, are discussed in further detail in section 2.3.3. Then wind output was very low, interchange with Victoria was constrained, and the combination of gas dispatch (1970 MW) and liquids fuels (150 MW) exceed 2000 MW. The impact of the combination of the removal of brown coal, constrained interconnection and low wind output is particularly evident in terms of the differences in gas dispatch at around 3:00 am on July 8th across the two years (around 1000 MW in 2016 as opposed to 350 MW for the corresponding time in 2015).

2.2.3 Load duration curves

A well known characteristic of variable renewable energy generation is that it is only available so long as the resource is available. As such, while renewable energy can add *energy* (MWh) to the system, it is less able to provide firm *capacity* (MW), when the system needs it.

Load duration curves are used to characterize electricity system demand. By ranking system demand in descending order, load duration curves illustrate the proportion of time that demand exceeds a certain level. Load duration curves can be used to estimate the generation mix in terms of the peaking, intermediate or mid-merit and baseload plant required to meet demand. Figure 2.14 shows the load duration curve for South Australia for FY16, showing that about 1065MW of capacity was required to serve the top 10% demand periods²⁸.

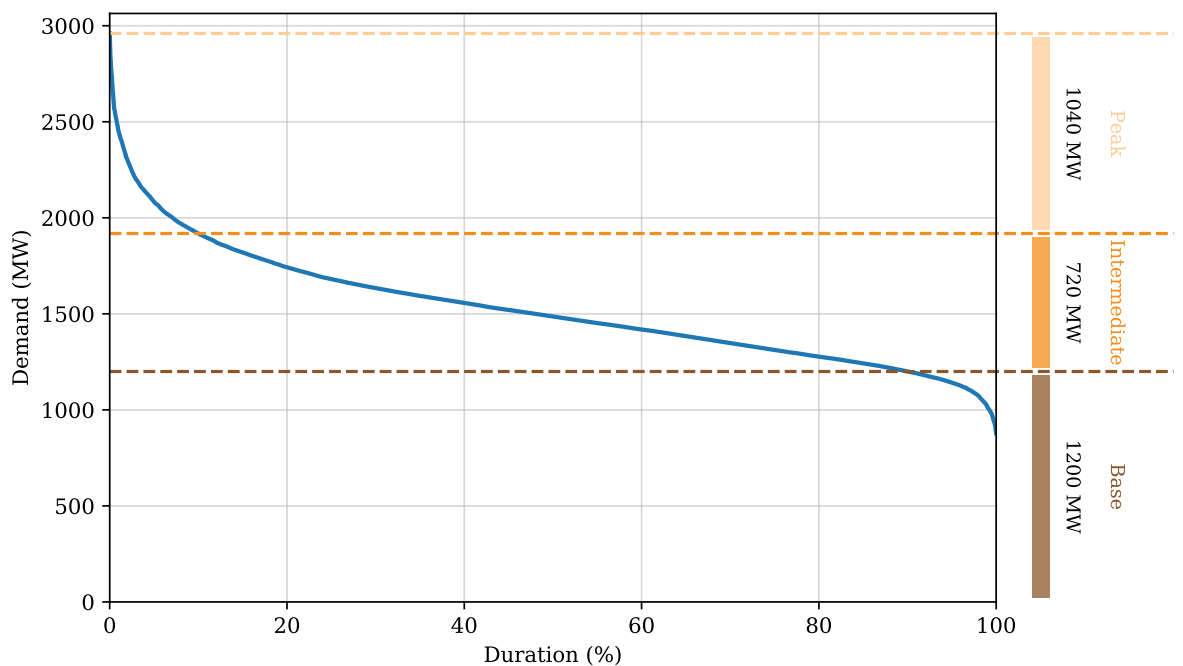


Figure 2.14: *Load duration curve for South Australia in FY16.* In this Figure the ‘baseload’ is the permanent minimum load that system is required to deliver, in this case at 690MW. For illustrative purposes I set the peaking capacity at the 10% duration level somewhat arbitrarily. As illustrated in figure 2.15, for systems with significant renewable generation the *net load duration curve* is arguably a better guide to the estimating the ‘baseload’.

²⁸The load duration curves for all mainland NEM regions for FY16 are shown in appendix B.1

The *net load duration curve* is a variant of the load duration curve that accounts for the impact of renewable energy generation. Subtracting generation types such as wind that are classified as either *semi-scheduled* or *non-scheduled* from the load curve sets the amount of required *scheduled* capacity. For South Australia this is essentially the load duration curve net of wind generation (figure 2.15). Note that net of wind, the additional capacity required to meet the top 10% demand periods in South Australia for FY16 was 1215 MW. The net load duration curve shows that for about 33 hours (or 0.4%) in FY16 wind supplied in excess of South Australian demand. An important consequence is that South Australia now has no real need for conventional *baseload* generation. It does however require some 3000 MW of flexible capacity, including intermediate, peaking and interchange, to ensure demand is served in times of low wind output.

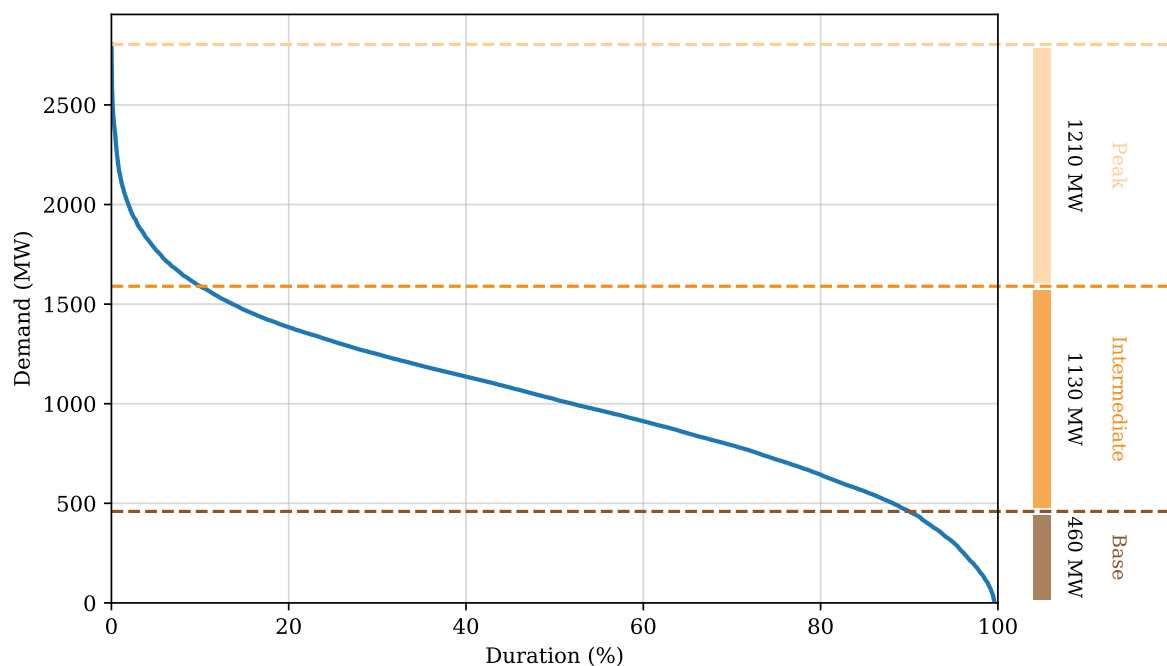


Figure 2.15: *Net load duration curve* for South Australia for FY16. The net load duration curve uses demand less wind generation. Note that the curve intersects 0 demand at about 99.6% duration, implying total wind dispatch exceeded total demand for 33 hours of the year. Also note that the highest net load increment (2805 MW) is only 65 MW lower than the highest load increment (2870 MW) and the greater intermediate and peaking (and/or interchange) capacity than implied by the *load duration curve* shown in figure 2.14

The load duration curve is essentially a representation of the cumulative density function of the distribution of demand (and net demand). Figure 2.16 shows the distribution of demand and net demand, and allows a clearer representation of the change distribution over time²⁹. Over the 10 year period shown, the distribution of demand has changed but is largely recognizable. The distribution of net demand on the other hand has changed dramatically. In the 2009, with relatively small amounts of wind generation installed, the net demand distribution is also comparable to the demand distribution. By 2018, the shape is remarkably different. Noteworthy features include the large range of net demand (from almost -1000 to 3000), alongside a noticeable broadening of the peak.

This phenomena manifests as even lower capacity factors for the generators that typically serve these peaks, as residual peak capacity required hasn't dramatically changed, energy output has declined. This is illustrated in figure 2.17 which shows that the amount of residual capacity

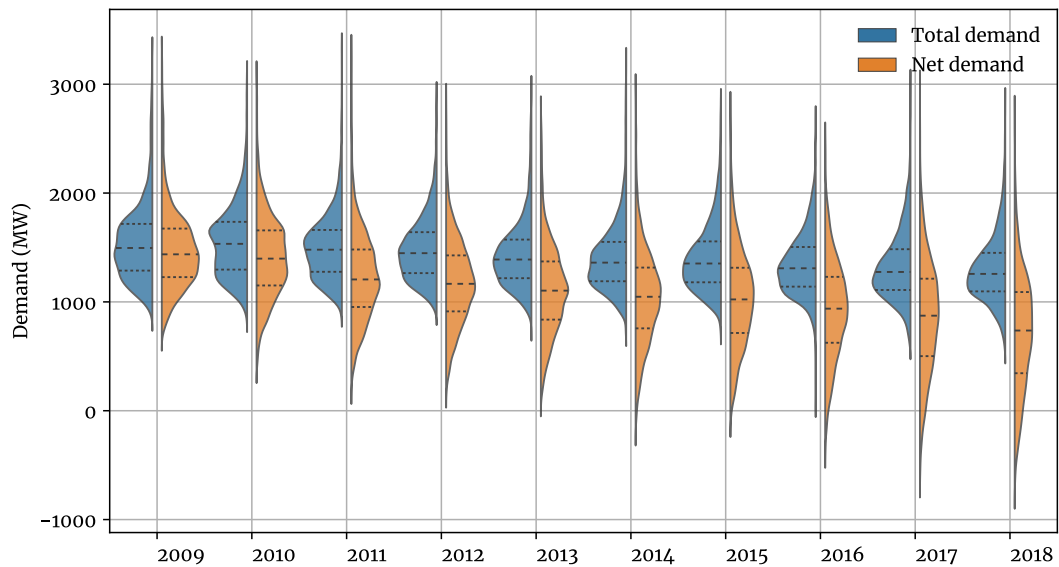


Figure 2.16: Violin plot showing the evolution of the demand and net demand distributions over time. Within each distribution, the dashed lines represent the median value, while the dotted lines represent the interquartile range. Note that for the net demand distributions, the maximum has remained largely unchanged, while the minimum net demand has decrease by the 1750 MW and the interquartile range has expanded. The demand distributions have not dramatically changed across the 10 year period.

²⁹The evolution of both the load duration curves and net load durations curves can be seen in B.5

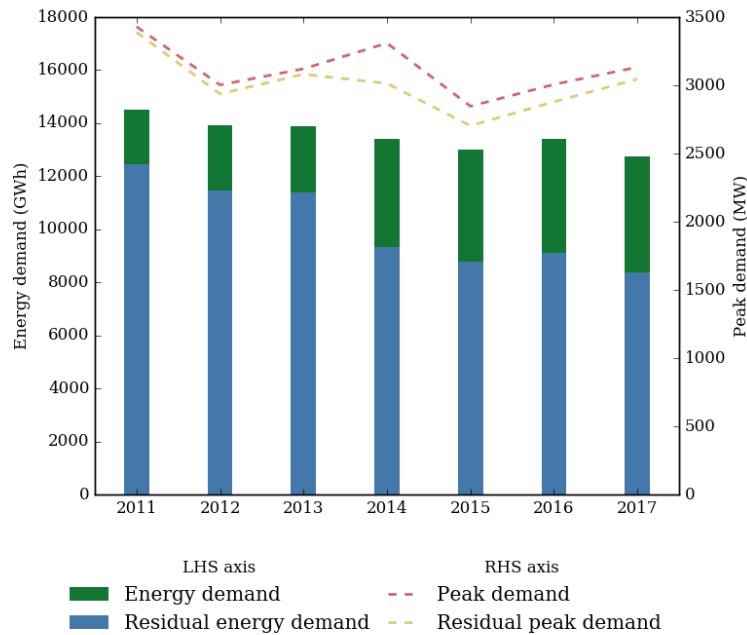


Figure 2.17: Residual energy (energy demand minus renewable energy contribution) versus residual peak (peak power demand minus renewable power generation) on an annual basis). As can be seen, the peak capacity required by non-variable resources has not dramatically changed over the previous 6 years. The energy delivered by these has reduced by over 30% over the same period.

(MW) required to be delivered by dispatchable resources has remained relatively unchanged over the past six years, with the addition of variable renewable energy. However, the amount of residual energy (MWh) required by the system has reduced by over 30%.

2.3 Wholesale power price dynamics in South Australia

Historically, South Australian wholesale prices have tended to be at the upper end of the regional price range. In the period FY08 through FY10 South Australian prices were significantly above other regions. Somewhat elevated prices in South Australia in comparison to other states are to be expected given its high proportion of gas powered generation, and the relative *peakiness* of its demand (AER 2018), as described earlier. Price volatility in South Australia is significantly higher than in both Victoria and New South Wales, though has been broadly similar to Queensland at times.

Figure 2.18 shows the wholesale price for South Australia over FY16, while Figure 2.19 shows the number of scarcity and negative price events on an annualised basis since FY05. In FY16, price spikes occurred throughout the year and were responsible for a significant proportion of value traded through the market, with the top-priced 5% trading intervals responsible for over 30% of market turnover in South Australia.

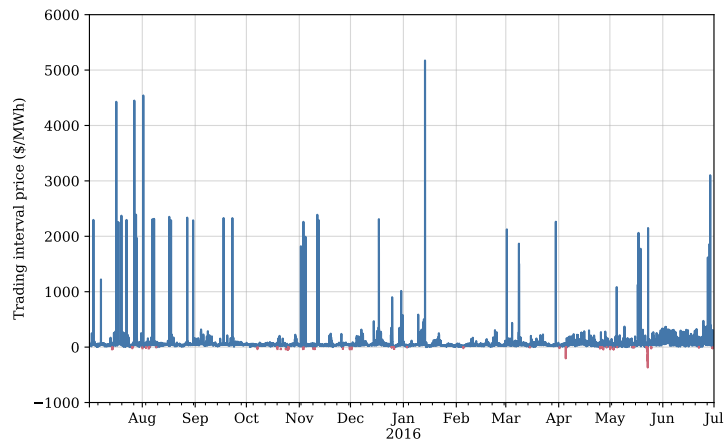


Figure 2.18: Wholesale settlement prices for South Australia in FY16, with negative prices shown in red. Note the anomalous number of scarcity events with prices in the range \$2300-2400/MWhr. As described in section 2.3.3 such prices typically indicate one 5-minute dispatch price spike to the market cap in the corresponding 30-minute settlement period.

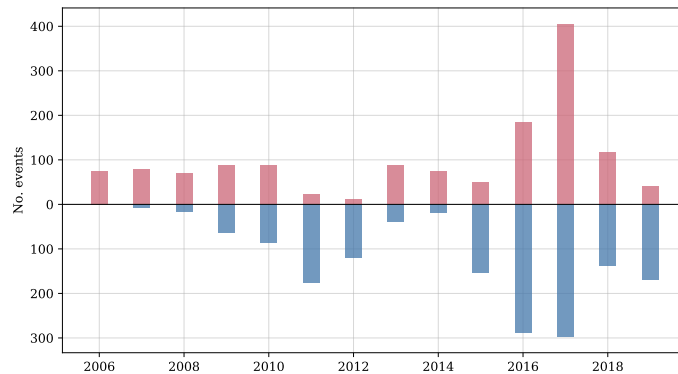


Figure 2.19: Number of scarcity or high-price (red) and negative (blue) settlement period (30-minute) events in South Australia since FY05, on a financial year basis. *Scarcity events* are defined here as settlement periods yielding prices greater than the standard cap contract price of \$300/MWh. In FY16, there were 288 negative price settlement events and 185 scarcity events, reflecting a recent increase in the volatility in the South Australian market. Not shown is the first month of FY17, July 2016, when there were 14 negative and 236 scarcity events, implying volatility is continuing to track at record high levels.

In the 2015 *State of the Energy Market* (AER 2015, page 51), the Australian Energy Regulator identified a range of factors that contribute to the elevated prices and price volatility in South Australia, including:

- high reliance of gas
- concentrated generator ownership
- anomalous generator rebidding behaviour
- thermal plant withdrawals
- limited import capability
- high levels of wind capacity

The *State of the Energy Market* (AER 2015, page 51) report emphasised the particular role of wind in contributing to price swings. In this section, I detail how these factors have impacted South Australian wholesale prices in recent times, focusing on the role of the renewable energy dispatch, gas pricing, competition and the “*missing money problem*”. This section delves into some of the drivers of these dynamics in more detail.

2.3.1 Renewable energy generation and merit order effects

For FY16 the total pass-through cost for the South Australian feed-in tariff schemes was approximately \$127 million (SA Power Networks 2016, page 99). As a result of the closure of the 16 c/kWh scheme in 2016, this annual cost decreased by nearly \$30 million to \$98 million for FY17. Renewable energy support schemes add approximately \$80 million to the aggregate cost of electricity in South Australia (see Section 2.1.4 for more details on the renewable energy support schemes in Australia).

Due to both excellent wind resources and supportive planning policy, South Australia has received a disproportionately large share of the new wind capacity installed under the large scale scheme. In calendar year 2015, South Australia generated over a quarter of the energy supported by this scheme, despite contributing only 6% of national electricity consumption. With demand for the certificates based on consumption across all jurisdictions, South Australia effectively

exported approximately around \$120 million of renewable energy ³⁰. The design of this scheme means that in effect the other mainland states are subsidising South Australia’s renewable energy portfolio, to the value of more than \$1 billion per decade.

In total, in 2015 the renewable energy support schemes added 2.78 c/kWh to the cost of electricity (AEMC 2015a, page 161) (see table 2.2). This compares with a typical retail cost of 29 c/kWh, of which about 13 c/kWh is estimated to be from competitive components of the bill such as wholesale and retail costs.

The merit order effect

It is now well documented that the addition of significant renewable energy capacity into liberalised electricity markets puts downward pressure on wholesale market prices. This phenomenon, known as the *merit order effect*, is demonstrably impacting electricity wholesale prices in Australia and abroad.

As explored in chapter 1, there are now numerous studies that have analysed the impact of renewable generation on merit order pricing, both overseas and in Australia (see section 1.1.2). Indeed one of the studies mentioned specifically explored the merit order effect in South Australia, using a range of econometric techniques to quantify the impacts of growing wind generation on prices (Forrest and MacGill 2013).

While initially contentious, the effect is now widely acknowledged in Australia and was highlighted by the Department of Prime Minister and Cabinet’s 2014 Review into the Renewable Energy Target³¹. As part of the review, dozens of modelling reports were prepared by different consultants on behalf of different stakeholders³².

Table 2.2: Contribution of renewable energy support schemes to retail electricity tariffs

	Cost (c/kWh)
Large-scale scheme	0.59
Small-scale scheme	0.48
Feed-in Tariff	1.71
Total	2.78

³⁰Based on historic certificate prices of around \$80/MWh. The price has since fallen, and most of LGCs will have been contracted at much lower prices.

³¹Also known as the Warbuton Review

³²The modelling reports prepared for the Renewable Energy Target (RET) review are listed in <http://www.wattclarity.com.au/2014/05/a-few-thoughts-on-the-ret-review-process/>

Whilst the individual reports offered a range of views, the Expert Panel concluded (Expert Panel 2014, page i):

Analyses suggest that, overall, the RET is exerting some downward pressure on whole-sale electricity prices. This is not surprising given that the RET is increasing the supply of electricity when electricity demand has been falling.

Expert Panel, 2014

The price impact of wind in South Australia has been documented by Forrest and MacGill (2013) and Cutler et al. 2011. Forrest and MacGill 2013 suggested that wind was primarily offsetting higher operating cost gas generation, and having a marked impact on prices, but was also significantly reducing dispatch of emissions intensive brown coal generation (see also figure 2.10). Using a range of econometric techniques, they estimated that for each MWh of wind generation, South Australian wholesale prices were reduced by 1.74 cents, decreasing the average wholesale price by \$8.05/MWh for the period March 2009 to February 2011.

The following analysis, while less rigorous, corroborates the analysis by Forrest and MacGill (2013). A negative correlation between wind and both wholesale price and scarcity events is illustrated in Figure 2.20, which summarises the calendar year 2015. For the bottom 10% wind generation events (i.e. above 90% wind duration), volume weighted prices averaged above \$60/MWh. In contrast for the top 10% wind generation periods (below 10% wind duration), prices averaged less than \$30/MWh.

Figure 2.20 clearly shows how, at settlement time scales, the wind generation applies a downward pressure on wholesale prices. However on longer timescales the relationship is more nuanced. In South Australia, the increasing wind generation over the last few years has also been associated with increased imports from Victoria (Figure 2.11), and following the closure of Northern, South Australia has also observed an increase in gas generation (see 2.10). Both interconnection and gas generation show positive correlation with price (see Figures 2.21 and 2.22).

The flow duration curve in the bottom panel of figure 2.21 shows for the top 10% import events (i.e. above 90% flow duration) hedged volume weighted prices were around \$60/MWh while for the top 20% export events (less than 20% flow duration) the price was less than \$20/MWh. In

2015, coal also played a role in South Australia but, as with wind, price was slightly negatively correlated with coal dispatch³³. The net price impacts of generator dispatch in 2015 therefore depended primarily on the balance of wind and gas dispatch as well as interchange with Victoria.

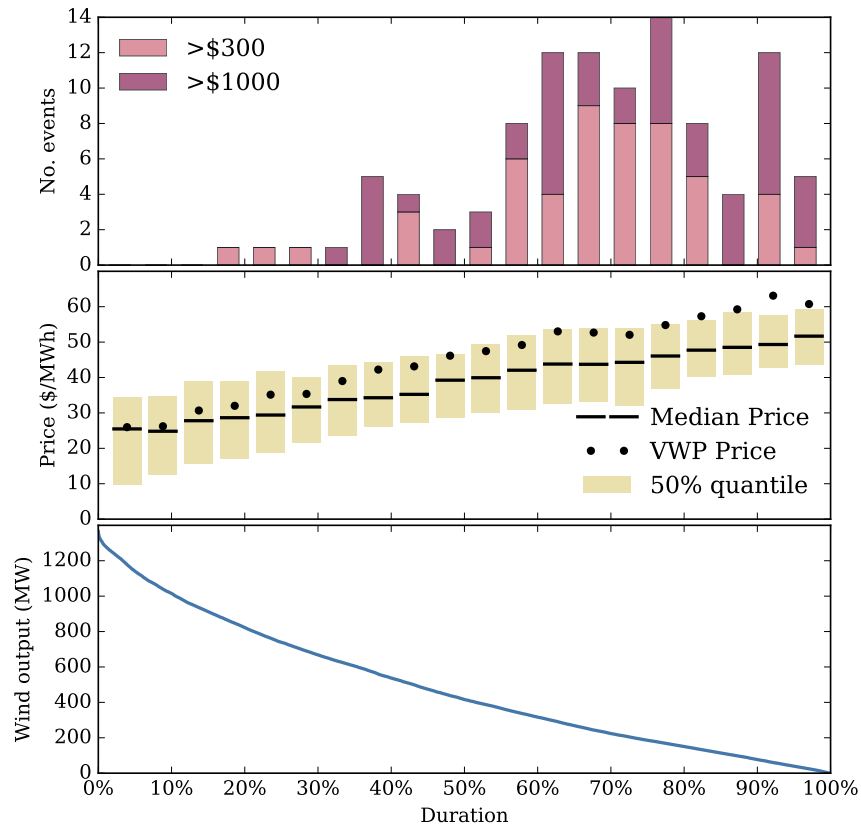


Figure 2.20: Relationship between wind generation, wholesale prices and volatility for South Australia for calendar year 2015. Top panel shows the scarcity events as a function of duration of wind duration. Middle panel shows hedged volume weighted prices as a function of wind duration. Bottom panel shows the wind duration curve. Note the absence of scarcity events when wind generation exceeded about 900 MW.

³³For the months of June and July in 2015, I find a correlation between wholesale price and coal dispatch of $-\$5/100$ MW only slightly less so than wind at $-\$6/100$ MW, whereas gas and imports were positively correlated (at $\$19$ and $\$12/100$ MW, respectively). For the corresponding period in 2016, following the closure of Northern, the correlations for wind and gas steepened significantly (to $-\$17$ and $\$33/100$ MW, respectively). In 2016, interconnector constraints meant high price events were not well correlated with interconnector flow.

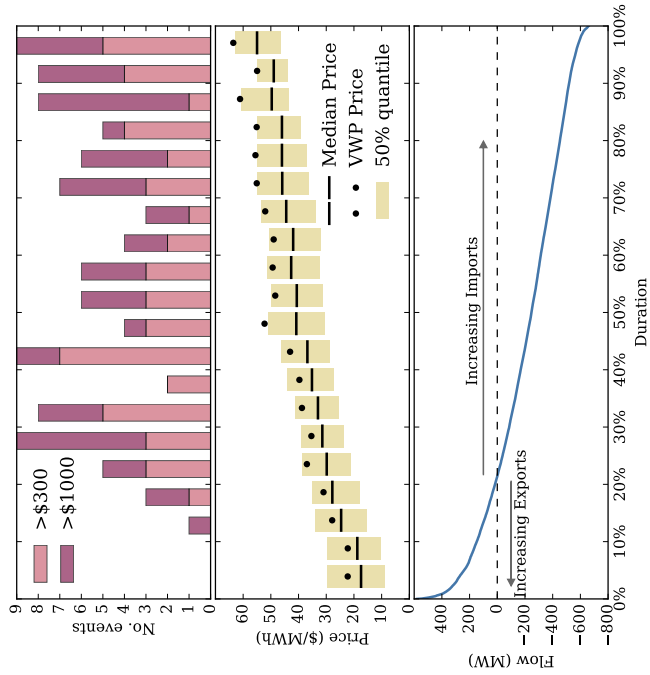


Figure 2.21: Relationship between interconnector flow, prices and scarcity events for South Australia for the 2015 calendar year. Top panel shows the scarcity events as a function of flow duration. Middle panel shows hedged volume weighted prices as a function of flow duration. Bottom panel shows the *flow duration curve* with positive flows for exports, and negative flows for imports. Note the lack of scarcity events for export greater than about 100 MW which correlate with periods when wind dispatch was close to or exceeding South Australian demand.

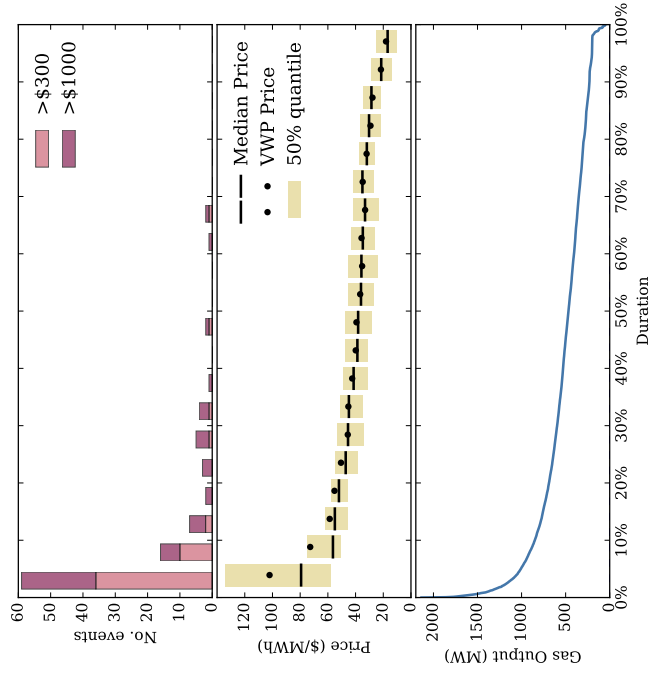


Figure 2.22: Relationship between gas generation, wholesale prices and volatility for South Australia for calendar year 2015. Top panel shows the scarcity events as a function of duration of gas duration. Middle panel shows hedged volume weighted prices as a function of gas duration. Bottom panel shows the gas duration curve. Note that scarcity events are highly skewed to gas flow durations less than about 15%, corresponding to dispatch of greater than about 1800 MW.

The case seems compelling that up until 2016, increasing wind penetration did suppress wholesale prices in South Australia, especially on a real (or inflation-adjusted) basis. For example, factoring out the effects of carbon pricing, which added about \$14/MWh to FY13 and FY14 prices in South Australia, nominal wholesale prices in the period FY11-FY15 were significantly lower than in the period FY07-FY10 (see figure 2.1)³⁴.

However, any significant ongoing reduction in wholesale prices due to increasing penetration of renewables, through either the merit order effect and/or increased capacity overhang, necessarily has implications for the profitability of the existing generation fleet. Not only are prices eroded by the addition of renewable energy, but volumes decrease as well. This strains the business model of such plants, which typically rely on high capacity factors to be financial viable, to the point at which they might exit. As much was claimed by Alinta Energy³⁵ in announcing the closure its Flinders Operations including the Northern Power Station³⁶:

The decline in demand for energy, as households have become more efficient and the number of industrial customers has declined, combined with policy settings designed to support significant growth in renewable energy generation have together had the effect of causing a significant oversupply of power available to South Australia. We now believe that there can be no expectation that the Flinders business can return to profitability.

Alinta Energy, 11th June, 2015

Other factors may have also contributed to the decision, including but not limited to supply issues at the Leigh Creek mine. Either way, the long-term price consequence of wind generation in South Australia must factor in the extent it has impacted the decision to close Northern, and the associated contribution to price increases.

Another factor clearly contributing to price rises in South Australia following the closure of

³⁴It should be also noted that factors other than wind, such as the Millennium Drought, have also significantly impacted price trends over the period FY07 through FY10.

³⁵<https://alintaenergy.com.au/about-us/news/flinders-operations-announcement>

³⁶Alinta Energy's Flinders Operations included the Northern and Playford B Power Stations in Port Augusta and the Leigh Creek Coal Mine. In their announcement on 11/06/2015, Alinta indicated the operation would not continue beyond March 2018 and may terminate earlier but not before March 2016. As it transpired, Northern was closed on May 9th, 2016

Northern has been the increased demand for gas in times of low wind dispatch³⁷. In addition media reports at the time suggest some large electricity consumers in South Australia are either currently under-contracted or un-contracted, and therefore have significant exposure to the wholesale market (Potter 2016). On the supply side, uncontracted generation tends to bid more strategically in order to encourage more contracting. Gas and gas prices, as well as competition concerns are discussed further in the following sections.

2.3.2 Gas demand and prices

In early 2015, exports of Liquid Natural Gas (LNG) commenced in Queensland, for the first time exposing the east-coast gas market to international pricing. The linkage to exports markets has transformed Australia's gas industry, dramatically increasing demand for gas across eastern and south-eastern Australia (AEMO 2016a, page 17).

AEMO has forecast that the development of LNG export capacity will almost triple the total demand for gas, with consumption from the export terminals projected to be over 1,400 petajoules (PJ) per annum by 2020. Consumption is forecast to grow at the average annual rate of 32.5% to 2020 and then remain flat (AEMO 2016a, page 14) (see figure 2.23).

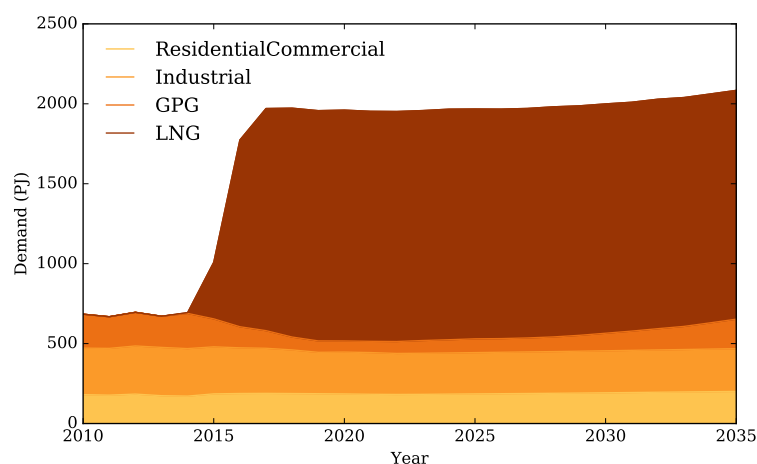


Figure 2.23: Historical and projected gas demand, data from AEMO, data from AEMO 2016a

³⁷ Another factors is the limited interchange capacity due to ongoing interconnector upgrades that have also meant significantly more gas and distillate have been dispatched in the winter of 2016 than would have been expected under normal interchange operating conditions

Impact on Gas Powered Generation

The dramatic increase in demand has increased prices across eastern Australia. This is reflected in both the Short Term Trading Market³⁸ (STTM) and contract prices and impacts the cost of gas powered generation (GPG) in two ways.

Firstly, in the short term, expiry of existing gas supply agreements exposes new contracts to rising domestic gas prices (AEMO 2016a, page 10). This is reflected in the reported fuel costs for Torrens Island. AEMO's 2013 National Transmission Network Development Plan (NTNDP) indicated Torrens Island fuel costs at approximately \$4.40/GJ³⁹. By 2015 the NTNDP⁴⁰ was projecting 2016 prices for Torrens Island would be in the range \$7.35–\$8.59/GJ for 2016, an increase of more than 70% over three years (see figure 2.24).

Secondly, because electricity consumption and production is typically not 100% contracted, gas generators will normally source some small fraction of their supply at the STTM spot price, which also represents the opportunity cost of selling the gas on the STTM. Given that gas

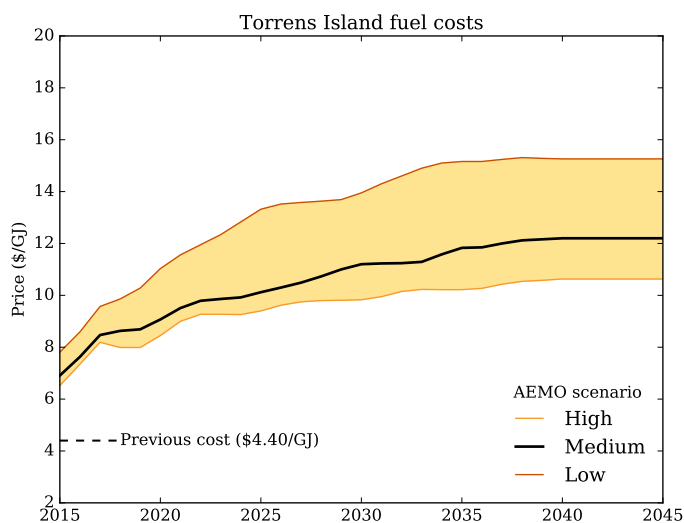


Figure 2.24: Fuel cost projections for Torrens Island, compared with previous years. Data from AEMO National Transmission Network Development Plan (NTNPD) 2015 and NTNPD 2013

³⁸The STTM is an 'overs and unders' market (sometimes called balancing market), where non contracted gas is traded

³⁹<http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>

⁴⁰<http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions>

generation generally sets the wholesale electricity price in South Australia, and the strong market linkages, it is unsurprising that price movements on the two markets is strongly correlated as shown in figure 2.25⁴¹.

For the 2015 calendar year, South Australian generators burned approximately 47.5 PJ of gas⁴². This is relatively low, compared with the previous five years. At these consumption rates, the increases in gas price reported by the NTNDP are estimated to have added \$140–\$200 million to the annual cost of electricity supply in South Australia, between 2013 and 2016⁴³.

As noted earlier, gas generation in South Australia has increased since the closure of the Northern Power Station. It is worth noting that the scale of increase is small compared to other factors driving demand in the gas market. To date, the output of Northern has only partially been replaced by gas-fired generation. Should all of Northern’s output be replaced by gas, the additional demand would be approximately 13 PJ, which represents less than 1% of annual demand projected from gas export contracts.

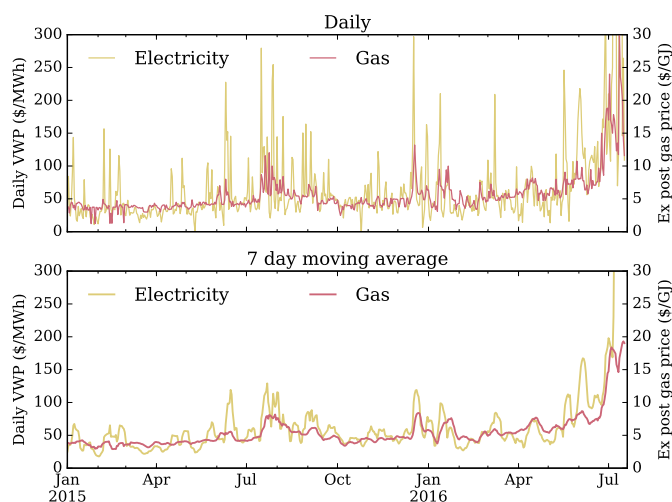


Figure 2.25: Relationship between South Australian electricity prices (daily volume weighted prices) and daily gas spot prices (ex-post acrsshortsttm prices)

⁴¹The correlation coefficient for the 7 day moving average is 0.86

⁴²see Table B.2 in appendix B.3 for outputs, heat rates and gas consumption by generator

⁴³See appendix B.3 for heat rates and production assumed

2.3.3 Competition

Competition has long been identified as an issue in the South Australian electricity sector, with a number of studies commenting on it. Carbon and Energy Markets has prepared reports on both market power in the South Australian electricity market (Mountain 2012) and the interaction of generation of renewable energy and market power (Mountain 2013).

The first of these reports discussed evidence for the exercise of market power in South Australia, and its implications for prices, concluding that the prices in the period analysed (2008 – 2011) reflected exercise of market power, rather than just scarcity. The second report concluded that the extent to which wind reduced market prices in South Australia was mitigated due to the exercise of market power. A report prepared for the South Australian Council of Social Services (Carnegie Mellon University 2016) in 2013 also examined 18 different high priced events in detail, concluding that generators deliberately sought to maximise profit in times tight supply.

In 2013, the AEMC's review on generator market power in the NEM more broadly reported that South Australia was potentially '*prone to inhibiting efficient investment and promoting the likelihood of substantial market power*' (AEMC 2013). The Commission accepted that there are some circumstances in which substantial market power could be exercised in the NEM, and specifically identified the potential for substantial market power to be exercised in South Australia.

Since the AEMC review in 2013, the closure of brown coal generation make the question of competition in South Australia worth revisiting. This section of the chapter builds on previous analysis of competition in South Australia. I begin by describing measures of market concentration and the potential for exercise of market power, including the *Herfindahl–Hirschman Index* and the *Pivotal Supplier Index*. I then discuss evidence for the exercise of market power in South Australia in terms of both cost price margins and specific instances where there is a *prima facie* case that supply has been either withheld or withdrawn with intent to impact market price.

Measures of concentration

Herfindahl–Hirschman Index (HHI)

The Herfindahl-Hirschman index (HHI) is a commonly used measure of market concentration and is reported annually by the AER in the ‘State of the Energy’ market report (AER 2015, page 60). The HHI is a static metric, calculated by summing the squares of the percentage market shares for all firms participating in a market. An HHI value of 10,000 is equivalent to a 100% share, and represents complete monopoly. An HHI value of 2000 is used by the Australian Competition and Consumer Commission (ACCC) to flag competition concerns (ACCC 2008, page 37), while the U.S Department of Justice considers markets to be *unconcentrated* at below 1500, *moderately concentrated* at 1500-2500 and *highly concentrated* at 2500 (U.S. Department of Justice and Federal Trade Commission 2010, pages 18 & 19).

Perhaps more apposite to energy markets are the UK’s Office of Gas and Electricity Markets (OFGEM) guidelines. The OFGEM regards an HHI exceeding 1000 as *concentrated* and above 2000 as *very concentrated* (OFGEM 2015, page 37). With a current HHI value of 1243 (OFGEM 2015, page 64), the OFGEM considers the UK wholesale electricity market *somewhat concentrated*.

The most recent AER ‘State of the Energy’ market report shows annual HHI trends for each of the four mainland states from FY09 through FY15 (AER 2015, Figure 1.29). AER’s HHI estimates lie in the range 1700-2450. In the three years FY12 through FY15, the estimates for South Australia, New South Wales and Victoria have all been in the range 1700-2000, while Queensland has been in the range 2300-2450.

Based on the trading rights indicated in the 2015 AER report (AER 2015, pages 40 to 41), I estimate the HHI for South Australia at the end of FY2016 was about 2900-3000 with all registered plants available⁴⁴. The value is substantially higher than AER has reported in the previous years reflecting the concentration of market share that followed the closure of Northern Power Station.

Of further relevance to the current state of market concentration in South Australia has been the effective *mothballing* of Engie’s 480 MW Pelican Point CCGT station for much of 2016⁴⁵. With Pelican Point effectively mothballed, I estimate South Australia’s HHI at the end of FY16 to have been 3300-3400, making it an *exceedingly concentrated* market.

⁴⁴Note that in our calculation of the current HHI I follow AER’s methodology of de-rating the wind and interconnector capacity, based on it’s contribution to peak demand

⁴⁵Pelican Point has been offline for much of the 2016 winter because Engie is believed to have on-sold its contracted gas to the LNG export market. At the request of the South Australia’s Energy Minister Engie was bought back online in July to help avert the ongoing *energy crisis*. Pelican Point is one of the most efficient CCGT gas stations on the NEM, with a thermal efficiency of 48%, much higher than AGL’s Torrens Island A (30%) and Torrens Island B (32%), that have continued to provide by far the largest proportion of gas output in South Australia

Pivotal Supply Index (PSI)

Indices like the HHI based on static measures such as installed capacity do not fully account for system dynamics through the exercise of transient market power. Several alternative measures have been proposed to capture such transients, including the ‘*Pivotal Supplier Index*’ (PSI) used here⁴⁶. The PSI calculates the frequency that some quantity from a given supplier is *required* to serve market demand. Under such conditions, the required participant becomes a *monopoly supplier* of the portion of demand that cannot otherwise be served (Bushnell, Knittel, and Wolak 1999, p. 7).

The PSI is calculated by subtracting the total amount of generation made available by other generators and interconnector import limits from the total demand. If a generator is required to meet the remaining demand, it is said to be ‘pivotal’⁴⁷. When operating in pivotal mode, a market participant is in a position to extract *monopoly rents*⁴⁸, as distinct from scarcity rents (see section 1.2.1 for further discussion).

Figure 2.26 below illustrates the pivotal supplier index for the four mainland NEM regions. This is based on the dynamic available generation and available import capacity, and the largest firm capacity controlled by a single participant. In South Australia, Victoria, and New South Wales, the pivotal supplier is AGL, while in Queensland it is the Stanwell Corporation. As shown in Figure 2.26, the PSI index for South Australia is typically much higher than for Queensland and Victoria, and mostly higher than New South Wales. Increases in New South Wales PSI in early 2016 are attributed to scheduled plant outages of non-AGL coal plants, combined with the AGL’s relatively large capacity holdings⁴⁹.

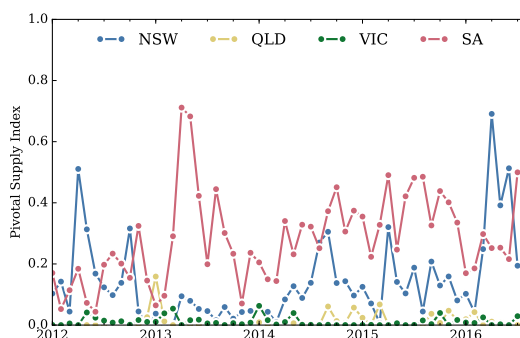


Figure 2.26: Monthly Pivotal Supply Index for the mainland NEM regions

⁴⁶The AER also uses the related ‘Residual Supply Index’.

⁴⁷A pivotal participant is *essential* to serving market demand, even considering all demand and imports available from the rest of the market.

⁴⁸Profits earned that result from the monopolist restricting supply to raise price without fear of entry by rivals

⁴⁹AGL’s New South Wales holdings include Liddell & Bayswater, which have a combined capacity of 4640 MW

Evidence of exercise of market power

Price-Cost Margins

The fundamental measure of the degree of market power exercised is the price-cost margin (Bushnell, Knittel, and Wolak 1999). In this Section I look at the price-cost margin for gas generation in South Australia. An important metric for gas generator margins is the ‘spark spread’ - the theoretical margin that a generator receives for a unit of power after deducting fuel costs. All other costs including operation and maintenance, as well as financing and capital costs, must be recovered from the spark spread margin.

The top panel in figure 2.27 illustrates the spark spread for gas generation in South Australia using standard assumptions⁵⁰. The theoretical margins for Queensland, New South Wales and South Australia are compared in the bottom panel, since February 2015. Prior to June 2016, the spark spread was relative constant and broadly consistent across the three regions, with the exception of the late summer and early autumn period when Queensland spark spread was elevated by a factor of about four. Prior to June 2016, the South Australian spark spread averaged \$17.34. That value is comparable to the spark spread in other, completely unrelated jurisdictions such as the United Kingdom⁵¹

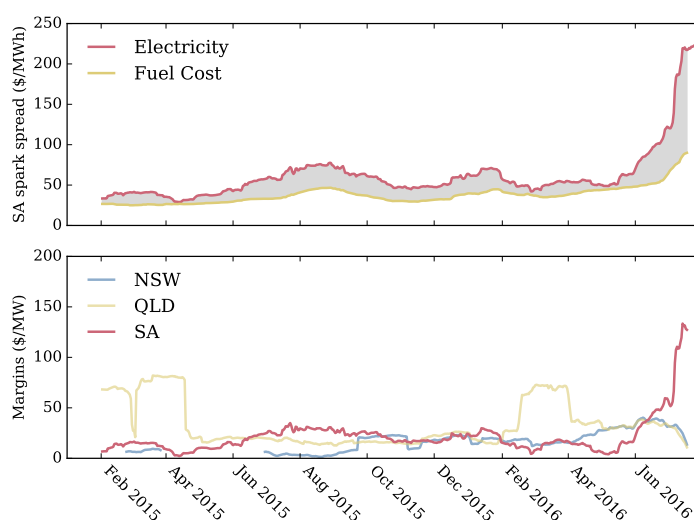


Figure 2.27: Spark spread for a typical Combined Cycle Gas Turbine with an assumed thermal efficiency of 50%, and a comparison of margins between regions

⁵⁰ As is standard, I use a thermal efficiency of 50% to calculate the spark spread. This allows comparison across jurisdictions and is *not* intended to represent the spark spread for a particular generator. A 50% efficiency is relatively high for gas generation stations in the NEM. For example, In South Australia thermal efficiencies range from 30% for Torrens Island to 48% for Pelican Point. At 50%, Tallawarra in New South Wales has the best efficiency of any gas plant on the NEM.

⁵¹ See UK's spark spread at <https://www.ofgem.gov.uk/chart/spark-and-dark-spreads-gb>

Since mid June 2016, there has been significant increase in the South Australian spark spread. On an individual generator basis, accounting for differences in their thermal efficiencies, the margins are estimated to have increased by between \$40/MWh (Torrens Island) and \$60/MWh (Quarantine)⁵². During this period, volume of sales also increased. Such behaviour contrasts with typical price volume trade-offs expected in efficient markets.

This is broadly consistent with an exercise of market power and extraction of monopoly rents. Monopoly rents are distinctly different to scarcity rents, which is discussed further in section 1.2.1. Assuming difference in margins is indeed a result of market power, approximately \$40–\$60 million of turnover since the beginning of June can be attributed to monopolistic behaviour.

The disparities between input costs of generation, including capital recovery requirements, and prices documented above shares remarkable similarities to an example described in the U.S. Federal Energy Regulation Commission investigation into Enron and the Californian power crisis⁵³. The U.S. investigation found that high prices during the Californian power crisis were more due to economic withholding by a pivotal generator than to market fundamentals⁵⁴.

Anomalous market behavior and ‘Gaming’

In 2003, the U.S. Federal Energy Regulatory Commission (FERC) investigated the trading strategies employed by Enron and companies in a report on *Price manipulation in western markets* (Federal Energy Regulatory Commission 2003a) investigating the Californian energy crisis in 2000 and 2001. In Part II of its report, the Commission specifically looked into two particular practices of concern: ‘*gaming*’ and ‘*anomalous market behavior*’ (Federal Energy Regulatory Commission 2003b) defining them as:

‘Gaming’ is taking unfair advantage of the rules and procedures .. to the detriment of the efficiency of, and consumers in .. the markets. ‘Gaming’ may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity.

‘Anomalous market behavior’ is behavior that departs significantly from the normal behavior in competitive markets that do not require continuing regulation or as behavior leading to unusual or unexplained market outcomes.

⁵²While Pelican Point was not generating during this period, the theoretical margins of the higher efficiency plant would have been approximately \$70/MWh)

⁵³Federal Energy Regulatory Commission 2003b, See Economic Withholding of Generation and Inflated Bidding During May to October 2000, Chapter VI page 45.

⁵⁴Similar to both the UK and South Australian margins above, the FERC determined capital recovery requirement for a hypothetical new power project is between \$16 and \$19/MWh

The Federal Energy Regulatory Commission cites evidence for such behaviour include:

- withholding of generation capacity under circumstances in which it would normally be offered in a competitive market;
- unexplained or unusual redeclarations of availability by generators;
- unusual trades or transactions;
- pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions, e.g., prices and bids that appear consistently excessive or otherwise inconsistent with such conditions; and
- unusual activity or circumstances relating to imports from or exports to other markets or exchanges.

In this section I investigate instances of ‘*gaming*’ and ‘*anomalous market behavior*’. Firstly, I look at the Angaston Power Station which physically withheld generation, taking advantage of rules around the calculation of settlement prices. Secondly, I look at evidence for the Torrens Island Power Station economically withholding generation capacity, and rebidding behaviour.

Physical withholding of generation

The Angaston power station is a 50 MW diesel power plant located in the Barossa Valley in South Australia. Snowy Hydro owns the plant and has the trading rights for its output (AER 2015, page 41 in).

Until recently, Angaston was a *non-scheduled* generator⁵⁵. Non-scheduled generators do not directly participate in the co-ordinated central dispatch process operated by AEMO. As such they are treated as *price takers*, receiving the market price for production. While non-scheduled generators do not directly participate in the central dispatch process that results in price setting, they can influence price outcomes, because they impact the amount of scheduled generation needed to meet demand.

Importantly, because non-scheduled generators operate outside the market dispatch process, scheduled participants can’t necessarily react to rapid changes in non-scheduled output (AER 2015, page 51 in). When the supply-demand balance is tight, rapid and unanticipated reductions in non-scheduled output can force prices to the market price cap. This issue has been identified by the AER (AER 2015,

⁵⁵ Angaston was re-classified as a *scheduled* generator at the end of May 2016

page 51 in) who stated ‘*strategic changes to the output of non-scheduled plant [can trigger] a series of high prices.*’

Due to a quirk of the market settlement process, extreme prices can be used by generators to increase revenues. There are two relevant prices for NEM dispatch and settlement - the *dispatch price* calculated on a 5-minute basis and the *settlement price* calculated on a 30-minute basis. The 5-minute dispatch prices are determined by the dispatch process, and the half hourly settlement prices are the simple average of the dispatch prices. Settlement prices are the prices that are paid by customers to generators. Note that the AEMC has recently reviewed the rules around 5-minute dispatch and 30-minute settlement pricing (See AEMC 2016).

One 5-minute price spike to \$14,500 substantially increases the price for the entire trading interval to above \$2,000 even if prices are negligible for all other dispatch intervals in the settlement period. Generators can take advantage of this by withdrawing capacity for a single interval, and then boosting output for the remainder of the half hour trading interval. Indications of strategic and systematic withdrawal by Angaston in such a manner is illustrated in figures 2.28 and 2.29. For the morning period between 7.30 am and 10:00 am on September 4th, 2015, the withdrawal of Angaston’s output for one dispatch interval in each of five successive settlement intervals corresponded to increases in the dispatch price by about \$170/MWh.

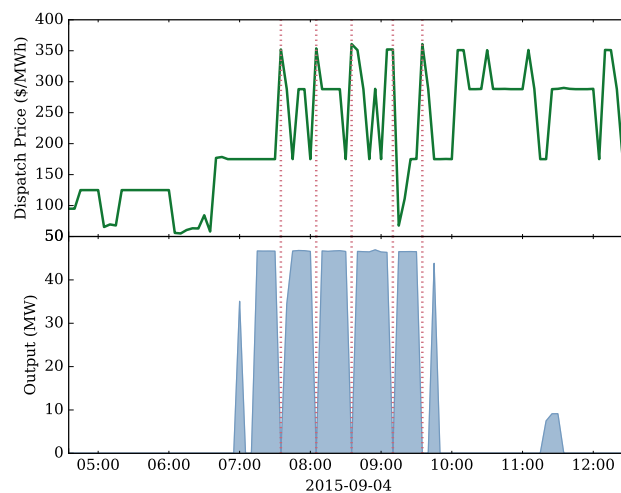


Figure 2.28: Example of systematic withdrawal of supply by Angaston Power Station impacting prices. The pattern of dispatch between 7:30 and 10:00 am on the morning of 4th September 2015, was characterised by a withdrawal for one dispatch interval in each of five successive settlement periods (bottom panel), each of which corresponded to a price spike of about \$170/MWh (top panel).

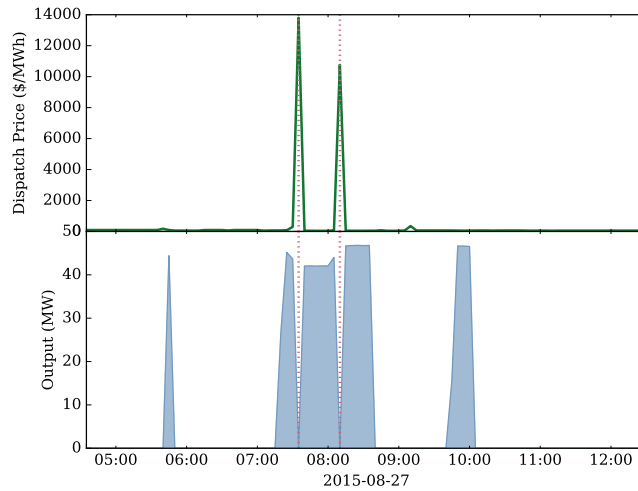


Figure 2.29: Example of withdrawal of supply by Angaston Power Station corresponding with extreme scarcity pricing events. Between 7:30 and 9:00 am on the morning of 27th August, 2015, on two separate occasions the withdrawal of dispatch (bottom panel) correlated with price spikes exceeding \$14,000 MWh (top panel).

I have identified 41 separate occasions in 2015 when withdrawal of Angatson’s output corresponded to increases in dispatch prices, with some driving the price to the market price cap (figure 2.29). Without those price spikes, the value of settlement price turnover would have been reduced by \$30.3 million⁵⁶.

Economic withholding and rebidding

Rebidding has been flagged as a potential issue by the AER. Generators can revise their offer up until the start of a dispatch interval through ‘rebids’ that shift the quantity of electricity they offer at particular prices (AEMC 2015b, page 2). Rebids that occur close to dispatch time can also trigger extreme prices, if the market is unable to respond adequately. In response to this issue, the AEMC has introduced ‘*bidding in good faith*’ rules, with additional requirements to record information for rebids close to dispatch.

I analysed the extent to which AGL bid capacity to high price bands (typically the market cap price) for the Torrens Island A Power Station. I also looked at the proportion of capacity that was available below and above \$300/MWh. In aggregate, Torrens Island A offered its entire capacity to the market at less than \$300/MWh 96.5% of time in 2015. For the remaining 3.5% of the year (or about 300 hours) some capacity was pushed into high price bands.

⁵⁶Price turnover was calculated assuming the settlement prices as the average of the remaining five minute period in the corresponding intervals

My analysis shows a correlation between periods of high scheduled demand⁵⁷ and Torrens Island A's bidding of capacity into high price bands. The proportion of time when some capacity was priced above \$300/MWh is clearly skewed to times of high scheduled demand. In 2015, for the top 10% of scheduled demand periods, the amount of time some capacity was bid into these high price bands was 16.7%. For the top 1% of scheduled demand periods it increased to 35%.

High scheduled demand periods coincide with low availability of wind generation. Whilst not necessarily indicative of abuse of market power, this behaviour is consistent with a 'pivotal' generator aware that some proportion of its capacity is required to meet demand.

Case study: competition during the July 7th “energy crisis”

The events of July the 7th 2016 elicited substantial media attention, much of it paying little attention to the factual details⁵⁸, not least of which those relating to concentration and market power. This case study investigates these in more detail.

On the 7th, wind output was very low (see figure 2.13), averaging about 100 MW, and exchange on the Heywood interconnector into Victoria was constrained due to upgrade works. Across the day, dispatch prices exceeded \$10,000 per MWh on 24 occasions, and the unhedged volume weighted price for the day was just above \$1400/MWh. The peak settlement price of almost \$8897.80 occurred for the trading interval between 7:00pm and 7:30pm. Settlement prices were above \$2000/ MWh for most of the afternoon and evening.

In the extreme trading interval between 7:00pm and 7:30pm wind was dispatching only 13.5 MW and other generation capacity displayed erratic dispatch patterns. The output from the AGL Torrens Island plants oscillated, reducing by 91.6 MW while the prices remained at the price cap (figure 2.30).

Uncertainties in the role of the interconnector make it difficult to be clear on what the cause of this generation pattern is. However, what is clear is that Torrens Island had bid an unusually high volume of capacity at the market price cap (see figure 2.31)⁵⁹. That is what may be expected if Torrens Island was engaging in *economic withholding*, consistent with it exercising market power as a 'pivotal' generator. I note that the oscillations maybe due to the interconnector becoming intermittently available, due to interconnector upgrade works, and thus intermittently displacing the capacity bid into the market at the price cap.

⁵⁷*Scheduled demand* refers to demand that must be met by *scheduled* generation capacity. Generation types such as wind that are classified as either *semi-scheduled* or *non-scheduled*.

⁵⁸For example, (Owen 2016) claimed that wind generation was drawing 50MW of demand from the grid at the time of the peak period, when in fact it was dispatching about 13.5 MW.

⁵⁹Other generators displayed similar patterns with the exception of some diesel generators, which indicates that their bids were higher than that of the diesel generators

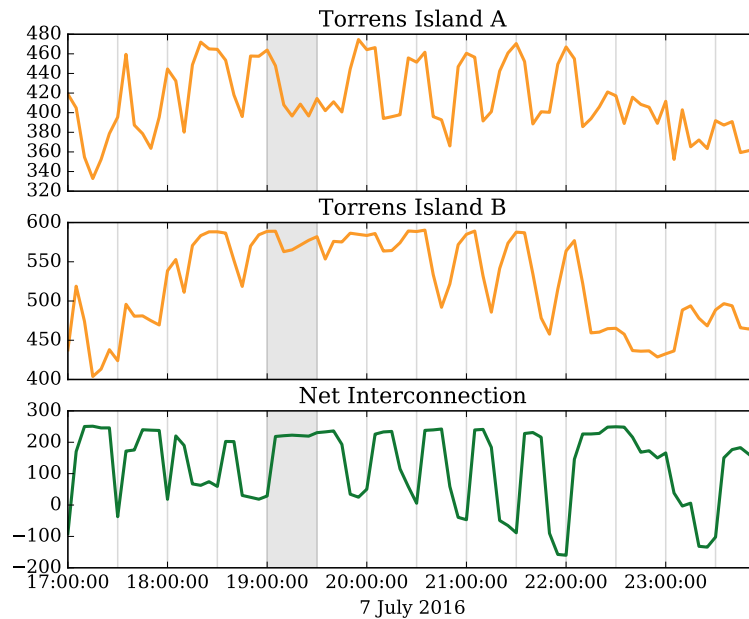


Figure 2.30: 5-minute dispatch interval output of Torrens Island A and B Power Stations in MW, on the evening of 7th July, 2016. In the peak price settlement period between 7:00 and 7:30 pm (shaded), prices exceeded \$10,000/MWh for five of the six dispatch intervals. Note that Torrens Island A reduced output during the peak pricing period. Dispatch output oscillations later in the evening have a distinctive 30-minute period, that also correlates with a succession of isolated extreme pricing events. While the output peaks on the half-hour, the prices peaked at the 5- and/or 10-minute dispatch interval in each 30-minute settlement period. The oscillations in gas dispatch were antithetic to oscillations in flow across the Victorian interconnectors. A more detailed diagram can be found in

Despite some uncertainties introduced by the interconnector behaviour during this critical time period, the analysis presented here provides a *prima facie* case for economic withholding on July 7th in South Australia. As in the U.S investigation into withholding supply (Federal Energy Regulatory Commission 2003b, See Economic Withholding of Generation and Inflated Bidding During May to October 2000, Chapter VI page 45) the Torrens Island example is suggestive of market power abuse.

As discussed in chapter 1, section 1.2.1 energy-only markets are predicated on the need scarcity events and extreme prices to incentivize capital investment. Scarcity events do however exacerbate the conditions for exercise of market power and create the potential conditions for extraction of monopoly rents. The extreme increase in price-cost margins relative to both historical averages and other regions, as discussed in section 2.3.3 and figure 2.27, suggest that the recent price increases in South Australia go beyond the *efficient equilibrium* and are indicative of exercise of market power.

⁶⁰The registered capacity of Torrens Island is 1280 MW, while the maximum capacity is 40 MW higher at 1320 MW

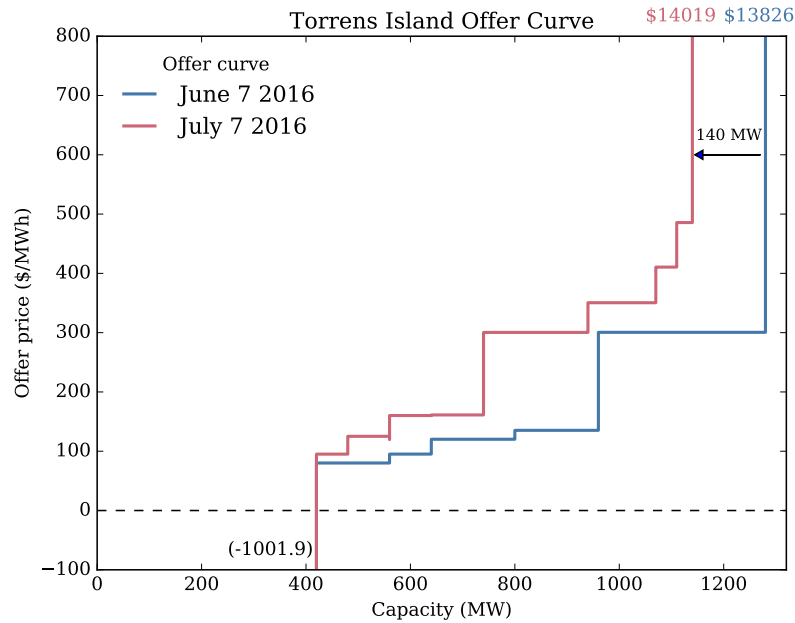


Figure 2.31: Combined final offer curve for AGL’s Torrens Island A and B for the 7:00-7:30 pm trading interval. The curves show the price at which AGL is willing to dispatch a certain amount of capacity. Torrens Island regularly has 40 MW⁶⁰ in the highest price band, typically at the market price cap (as illustrated in the blue line). On July 7th a total 180 MW was rebid to the market price cap. The last bid for the 7:00-7:30 interval on July 7 occurred at 6:35 pm after a series of at least 9 rebids for that interval during the afternoon.

2.3.4 Security of supply

Following the ‘black system’ event, the reliability and security of the South Australian system, as well as the NEM more broadly, has featured more prominently in public discourse around energy policy and political debate about the energy system. Following the event, the Council of Australian Governments (COAG) initiated an “*Independent Review into the Future Security of the National Electricity Market*”, the so-called Finkel Review. Increased security and reliability were key themes in the Finkel Review, which included a key recommendation to develop a *Generator Reliability Obligation*. The NEG also includes a ‘reliability obligation’.

Thus far, this chapter has mainly focused on issues relating to reliability (for example adequacy of supply, wholesale market dynamics). Security of supply is also fundamental principle underpinning the operating power systems and is discussed further here.

In public discourse, the *security* and *reliability* terms are often confused, or (incorrectly) used interchangeably. In the context of the NEM and power systems more broadly, *security* relates to the

operating state of the power system, and is a measure of the ability of the power system to tolerate disturbances. A *secure* system can handle large faults or incidents such as the loss of a large generator, load or transmission line⁶¹.

The security of the power systems is maintained through operating the power system within safe operating limits, and provisions for ‘primary’ frequency control and ‘secondary’ frequency control, among others. In the NEM this is primarily facilitated by the Frequency Control and Ancillary Services (FCAS) market⁶².

Very large unanticipated changes in both supply and demand do occur occasionally (see figure 2.32), and from a system security perspective, the implications of a trip of a large coal generator is much greater than that of the maximum likely forecast error for either demand or wind generation (see appendix B.4 for a comparison forecast errors). Managing such large unexpected deviations is challenging, however the system is designed to cope with it. The availability of supply during such unpredictable events is managed through security mechanism provisions, such as the FCAS markets.

Following the ‘black system’ event, other issues relating to system security shot to prominence, namely ‘inertia’ and ‘system strength’⁶². The dominate renewable energy supply, rooftop solar and wind power, don’t inherently provide these services to the system. As renewable capacity expands, and traditional thermal generators withdraw from the system, the reduction in these services is likely to become more challenging to the secure operation of the grid.

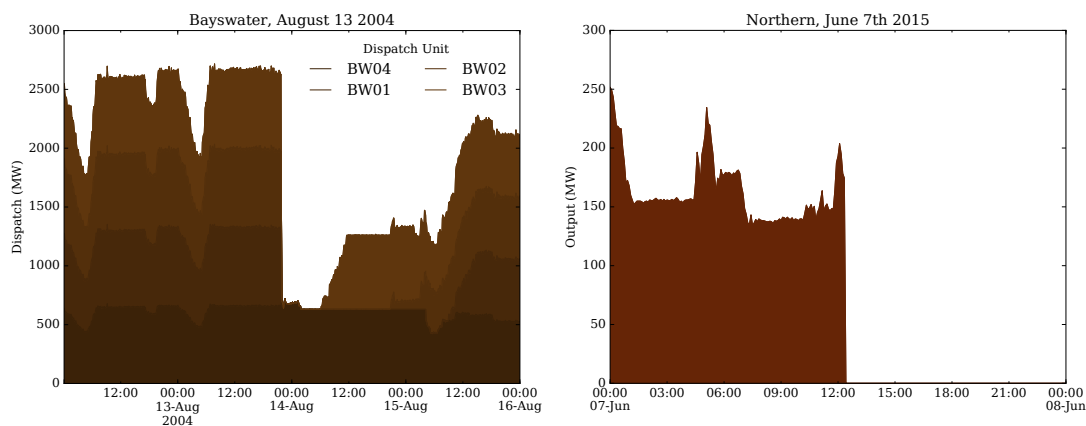


Figure 2.32: Examples of forced outages at two different power stations, resulting in large unexpected changes in generation output. The left shows an incident when three units at Bayswater (New South Wales) tripped off on the 13th August, 2004, dropping almost 2000 MW in 10 minutes. The right shows a tripping event at Northern on June 7th June, 2015, dropping almost 170 MW.

⁶¹For the definition and a comprehensive discussion of reliability, refer back to section 2.1.1.

⁶²These concepts are explored in more detail in chapter 5

2.4 Summary

This thesis aims to provide further insight into how the energy-only market might evolve with high penetrations of renewables, and the context of a transition to a lower carbon energy system. Understanding such issues is of critical importance to rapidly decarbonising the sector.

The South Australian market region within Australia's NEM is an exemplary system to study, with respect to understanding the impacts of new technologies on the energy-only market systems. The remarkable changes in the South Australian system, combined with the theoretically pure implementation of the energy-only market, is second to none when it comes to analysing such designs and how they might function in the transition to a lower carbon energy system.

As part of any transition in the electricity sector, abrupt shifts in generation will necessarily accompany closure of large power stations. South Australia has already experienced such a closure, with the exit of a large coal fired power station (on regional basis size), alongside the expansion of renewable energy generation. This shift has brought with it several opportunities and challenges, as detailed in this chapter. The tightening of the demand-supply balance inevitably created significant upward pressure on price and increased volatility as is consistent with the notion of the *capacity cycle*. Competition issues and gaming opportunities have come to fore, with the increased market concentration that inescapably comes with the withdrawal of a large amount of capacity. Security of supply and reliability concerns have emerged as large synchronous generators have exited the market, largely replaced with non-synchronous technologies.

This thesis aims to contribute to the existing literature by explore these issues, and draw conclusions on impact of technology changes on the market and consequences and challenges to the market design. Chapter 3 explores the value of energy storage in this system, how storage technologies might optimally operate, and how it compares with alternative options to ensuring reliability. Chapter 4 takes a close look at the market design, specifically misalignment of dispatch and settlement, and how that results in inefficient outcomes, gaming opportunities and creates barriers for important new entrant technologies. Finally, chapter 5 looks at how these new entrant technologies are able to contribute to security of supply, and disrupting the way this has traditionally been managed.

Chapter 3

Value of storage in energy-only markets

This chapter was published in the Journal of Applied Energy. The chapter includes an extended methods section and an extended case study compared with the published paper.

3.1 Introduction

Volatile prices are a common feature of competitive wholesale electricity markets, and especially energy-only markets (Griffin and Puller 2009). 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 (Jamash and Pollitt 2005).

Electricity has generally been considered a non-storable commodity (Crespo Cuaresma et al. 2004). 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 (Anderson, Hu, and Winchester 2007). Flexible generators such as Open Cycle Gas Turbines (OCGT) are commonly used to provide this peak capacity and respond to 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 (Holz and Von Hirschhausen 2013).

Electricity storage technologies can also provide peak demand capacity in addition to grid reliability and assist the integration of renewable energy sources (Dunn, Kamath, and Tarascon 2011). Large-scale electricity storage offers an alternative to gas for power system balancing, as variable renewable generation continues to expand (Knopf et al. 2013). In Australia the market operator (AEMO) recently undertook a study exploring an Australian market powered entirely by renewable energy (AEMO 2013a). 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 I 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 (Sioshansi 2008; Pfeifenberger, Spees, and Schumacher 2009). 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. I 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 (AEMO 2014). As such, this study provides interesting and useful insights into the energy and capacity value of storage in an energy-only electricity market in a system with high renewable energy penetrations.

Literature Review

Energy storage technologies have historically been uneconomic to install and operate, with the exception of pumped hydro. Increasing penetration of variable renewable energy technologies, such as wind and solar, have renewed interest in evaluating the arbitrage opportunities (Brad-

bury, Pratson, and Patiño-Echeverri 2014; Foley and Díaz Lobera 2013).

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 volatility¹.

Typically the economic viability of storage has been evaluated with a price-taker model, using historical market prices (Das, Krishnan, and McCalley 2015), sometimes referred to as a ‘small device’ energy arbitrage model. For example, in the U.S., Sioshansi et al. (2009) analysed the PJM interconnection, Walawalkar, Apt, and Mancini (2007) analysed the NYISO interconnection and Bradbury, Pratson, and Patiño-Echeverri (2014) analysed the value of storage in seven U.S. wholesale markets. These approaches do not consider non-arbitrage value, but both Bradbury, Pratson, and Patiño-Echeverri (2014) and Sioshansi et al. (2009) recognised that energy storage may have additional value in the ancillary services and capacity markets.

Internationally, Figueiredo, Flynn, and Cabral (2006) investigated and compared the economics of 14 power markets. Graves, Jenkin, and Murphy (1999) looked at the arbitrage opportunities of storage in the U.S., and compared these to international markets. Connolly et al. (2011) compared optimal arbitrage profits across 13 electricity spot markets. These papers also consider different operational strategies to evaluate ‘real-world’ arbitrage opportunities, incorporating the uncertainty of future electricity prices.

Increasingly, attempts have been made to assess storage devices by co-optimising energy arbitrage and the provision of energy reserves. Drury, Denholm, and Sioshansi (2011) quantified the additional value of reserves for a Compressed Air Energy System (CAES) in several markets. More recently, Das, Krishnan, and McCalley (2015) 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, Krishnan, and McCalley (2015) 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

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

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, Denholm, and Sioshansi (2011) also used reserve price data, separate from the energy market data, to optimally dispatch the storage device.

In this paper, I 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, Krishnan, and McCalley (2015) work I use historic market data in an energy-only market, with a single market for both energy and capacity. However I 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, I describe some key characteristics of the NEM. Then I characterise the basic relationship between storage capacity and the arbitrage value of energy storage, using a small-device energy arbitrage approach, assuming an optimal operating regime and ‘*perfect foresight*’ of electricity price. Thirdly, I determine the same 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 I analyse how hedging strategies typically used in the supply of *capacity* to the market might affect the value. I finish with a discussion of the implications of the analysis and how the value may evolve over time.

The Australian electricity market

The 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 an exemplar of an energy-only market (Pfeifenberger, Spees, and Schumacher 2009), with a price cap different from, but related to 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 (Sioshansi 2008)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 (Simshauser 2010a).

The NEM consists of five interconnected regions, with the dispatch process centrally managed

²The 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.

by the market operator AEMO. Wholesale Regional Reference Prices (RRP) are calculated for each region and are the settlement price for all generators in the region. All transaction in the NEM are settled against a half-hourly spot price. However, dispatch within the NEM is optimised by the operator at 5 minute intervals, and as such the NEM is considered a ‘fast market’. Fast markets (with short dispatch intervals) provide incentives for dispatchable, flexible capacity which would otherwise be met by regulation reserves (Riesz, Gilmore, and Hindsberger 2013). This is reflected in the relatively small size of the Frequency Control Ancillary Services (FCAS) market compared to the wholesale spot market. In 2014, payments through 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 figure 3.1, 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 (2,657 MW) was some 2.5 times greater than the minimum demand (1,080 MW). In 2010-11 summer in South Australia, the daily peak demand varied between 1,500 MW and 3,400 MW (AEMO 2011).

Network constraints between the regions, in combination with the regional differences in load

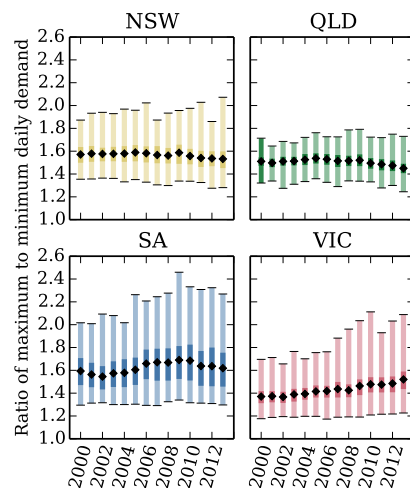


Figure 3.1: Box plots illustrating the relative variation in daily demand, for the four main NEM regions (calculated as a ratio of the maximum daily demand over the minimum daily demand)

and generation capacities, translate into differences in both regional prices and price volatility. Figure 3.2 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 in the NEM was growing at about 2% each year. Since 2008 there has been a reduction in demand for electricity in the NEM with the decline averaging about 1.5% per year. The reduction in demand, combined with a return to average rainfall conditions, has led to increasing overhang in generation capacity on the NEM, and a consequent general reduction in volatility. The system peak for last financial year was approximately 33 GW and the total registered capacity was approximately 52 GW³, suggesting a capacity overhang of 37%.

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 1,203 MW (AEMO 2013b). Rapid deployment

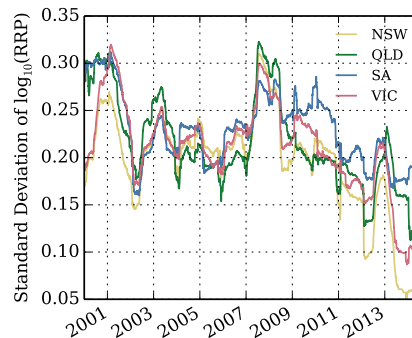


Figure 3.2: Rolling standard deviation of $\log_{10}$ of the regional price for the four main regions

³Due to inter-regional transmission constraints, not all of the registered capacity can contribute to the capacity overhang of the NEM

of photovoltaic solar in recent years has also seen the installation of an estimated 540 MW of rooftop solar systems to August 2014 (Clean Energy Regulator 2019). Together, this represents a significant penetration of renewable energy, in a region with a mean demand of about 1,460 MW⁴), and a system peak of 3,385 MW (in 2011). The remaining generation capacity is dominated by gas (2,672 MW) and brown coal (770 MW). The annual electrical energy consumption in 2013 was 13,330 GWh (AEMO 2013b).

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.

3.2 Assumptions and methods

In the analysis below I 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 affect 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. For this analysis I focused on the the energy market, and did not explicitly co-optimize with the ancillary market. Chapter 5 considers co-optimisation with ancillary services in detail. The analysis is device agnostic, applicable to any storage device technology.

I use a COIN-OR Linear Program (Mitchell and Dunning 2011) solver to find the optimal dispatch, that maximises the arbitrage profit for a hypothetical merchant⁵ storage facility in the South Australian Market region for a range of storage capacity scenarios from 0.5 to 10 hours storage. The power capacity is effectively dimensionless: under the small device assumption, optimal operation of a 1kW unit with 5 hours storage would be the same as a 20 MW facility with 5 hours of storage.

In this 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

⁴South Australian demand has been declining since 2011, in part as a result of increased solar generation 'behind the meter'.

⁵Un-contracted power plant, entirely reliant on spot market outcomes.

(hrs). I 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 hours of charging is required for 7.5 hours of discharge generation). I explore sensitivity to round trip efficiency, as discussed in section 3.6.

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 prices a full year ahead. 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:

$$s_t = s_{t-1} + \eta \times (c_t - d_t)$$

$$0 \leq s_t \leq s_{max}$$

$$c_t, d_t \leq 1 \text{ (unity power capacity)}$$

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.

3.3 Relationship between storage configuration and value

Figure 3.3 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. Figure 3.4 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.

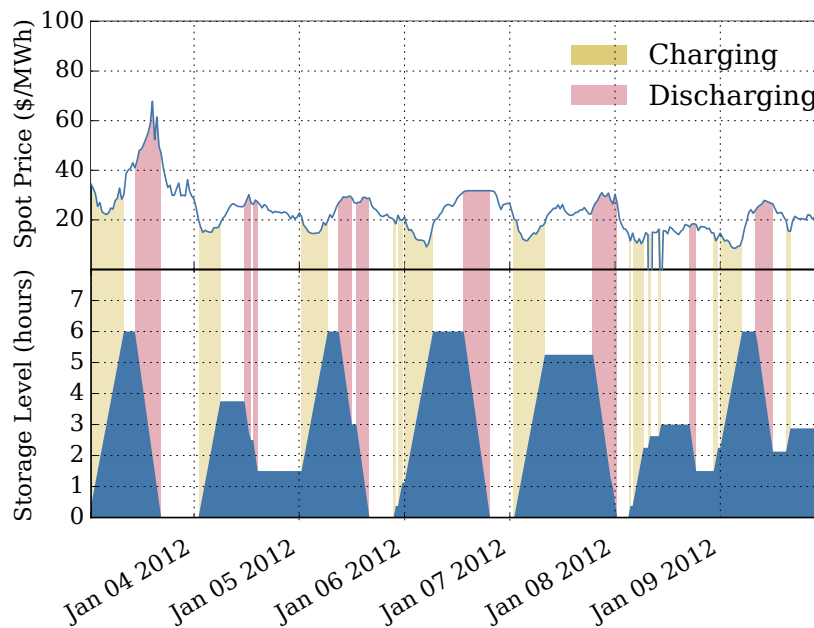


Figure 3.3: Optimal operation of storage device, a week in January, 2012 in South Australia.

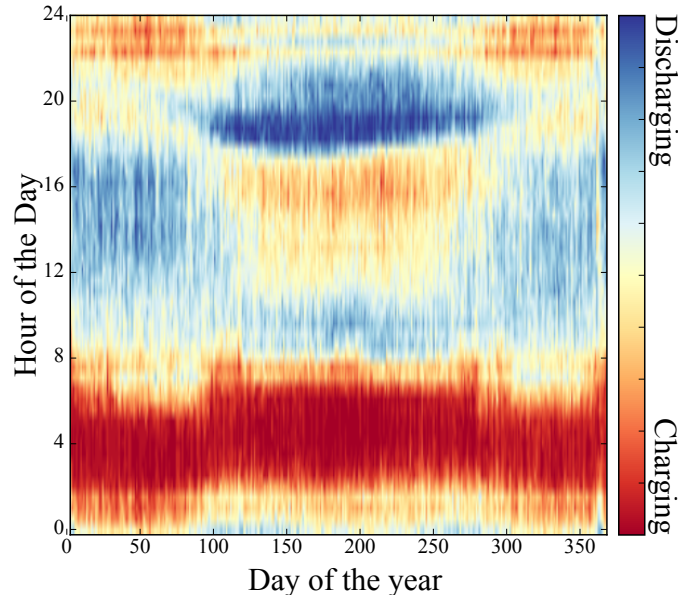


Figure 3.4: Optimal operation characteristics, for winter and summer months of the year. Plots show number of days that a device is charging or discharging at different hours of the day.

Figure 3.5 shows the value of a storage device (\$/kW-year) 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 arbitrage value mirrors the trends in wholesale price volatility in Figure 3.2 as well as the number of days where ambient temperature $\geq 38^{\circ}\text{C}$ in Adelaide (see Figure 3.6). 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 relationship and the result that merchant arbitrage revenue is generated on only a few days of the year. This will be discussed further below.

Figure 3.7 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 relation-

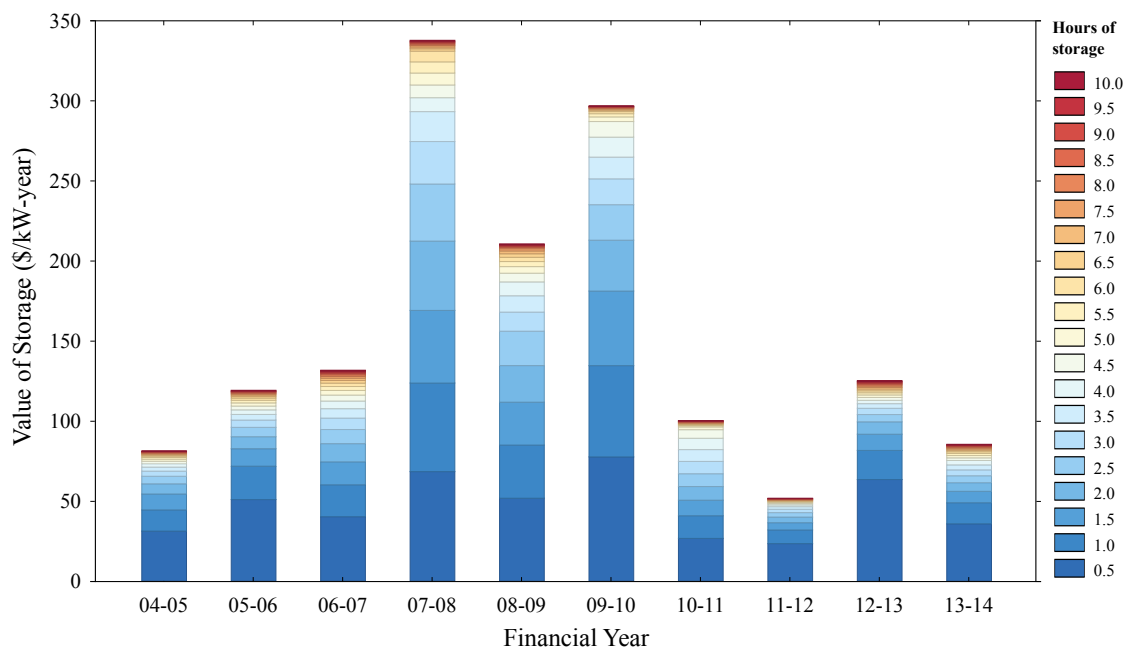


Figure 3.5: Value of Storage by financial year and storage capacity, for South Australia

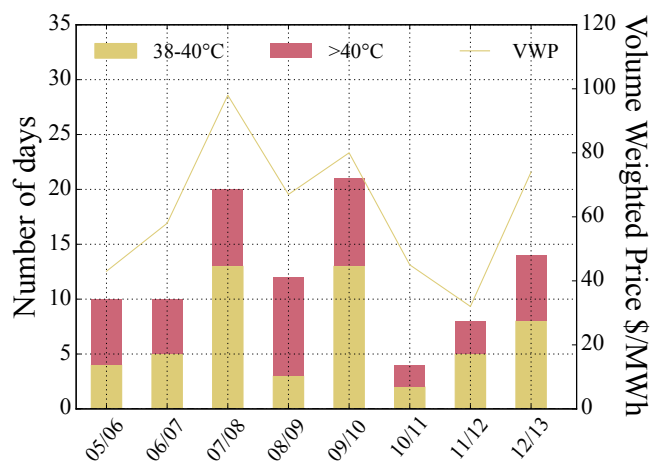


Figure 3.6: The volume-weighted electricity prices follow a very similar pattern to the number of days in South Australia reaching 3°C or higher

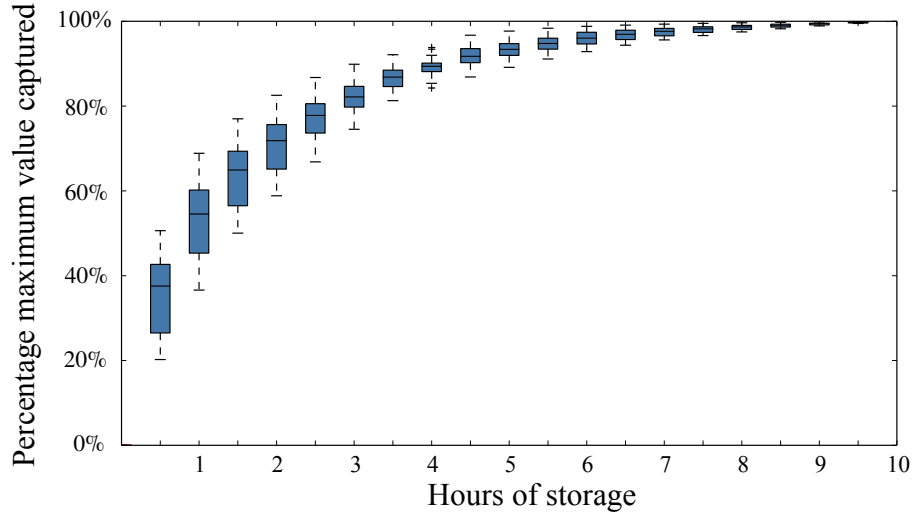


Figure 3.7: Normalised value of storage, as a function of hours of storage (the value of storage as a percentage of the maximum value possible for a given financial year). Box plots represent the distribution of values captured over all financial years modelled.

ship 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 (Sioshansi et al. 2009).

The optimisation time horizon has limited impact on the distribution and magnitude of the values illustrated in Figures 3.5 and 3.7. 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 relatively low power capacity cost, systems with a small amount of storage (in hours) may be more economically viable. A technology with relatively high power capacity costs may opt for a larger amount of storage (in hours). The interaction between arbitrage opportunity and 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

Year	VWP _d	VWP _c	Δ	Median _d	Median _c	Δ
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

Table 3.1: Comparison of volume weighted prices (VWP) and median for charging (subscript c) and discharging (subscript d) under optimal operation in SA since 2012

a few hours of the year. Figure 3.8 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 to 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 figure 3.8), 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).

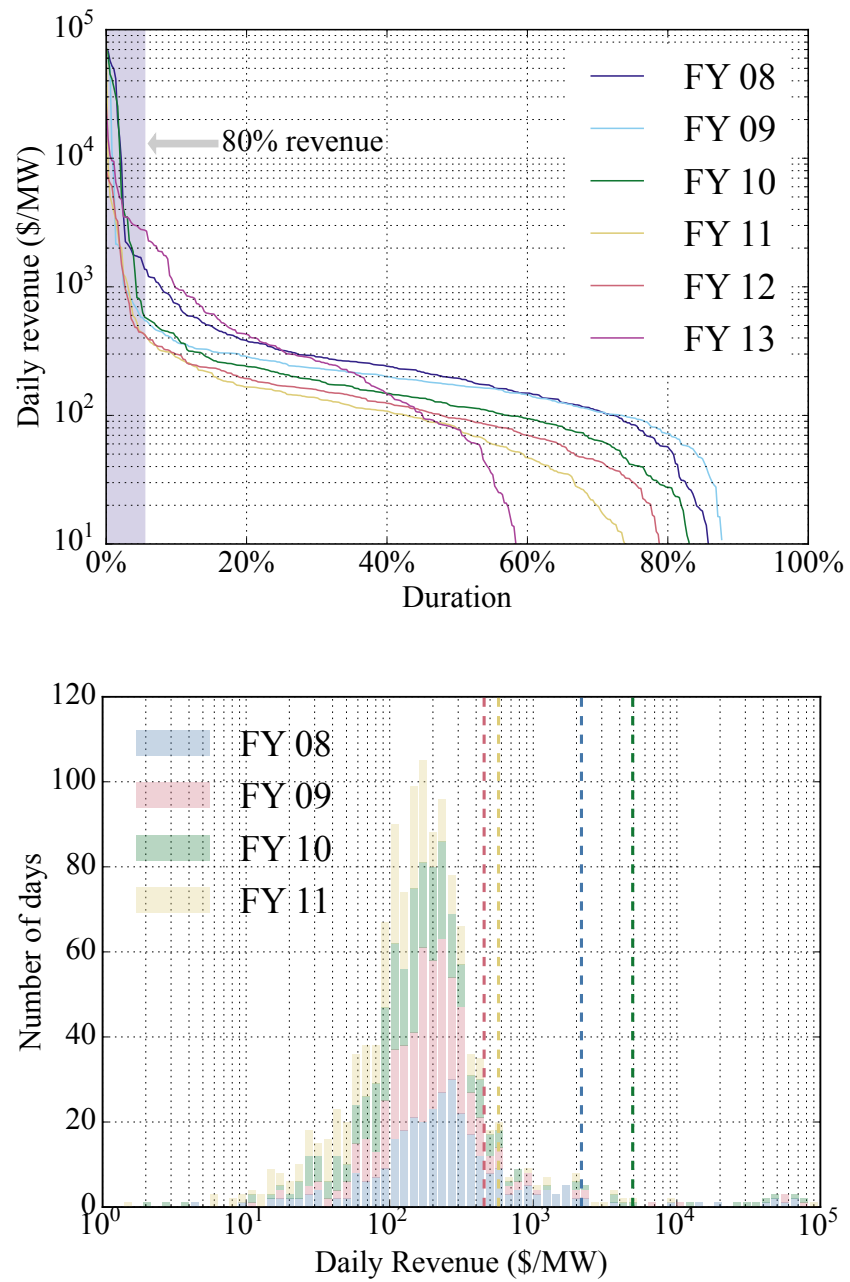


Figure 3.8: Top panel: revenue duration curves for financial years 2009-10 through 2013-14 for South Australia. Bottom panel: histogram of daily revenue over four financial years. Vertical lines illustrate the days point above which 80% of revenue is generated.

To illustrate this point, consider a case where average prices are \$50 per MWh, to be 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).

3.4 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 of an energy only market necessarily entails some uncertainty of future prices. In this section, I 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. (2011) compare a '*historical strategy*' and a '*prognostic strategy*' with an optimal strategy and Sioshansi et al. (2009), use a '*back casting*' approach, based on historic prices for the previous two weeks. In this analysis, I 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. (2011).

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. Figure 3.9 illustrates how the pre-dispatch forecast accuracy improves as the forecast trading interval approaches.

Figure 3.10 compares the potential value of storage using pre-dispatch prices and perfect

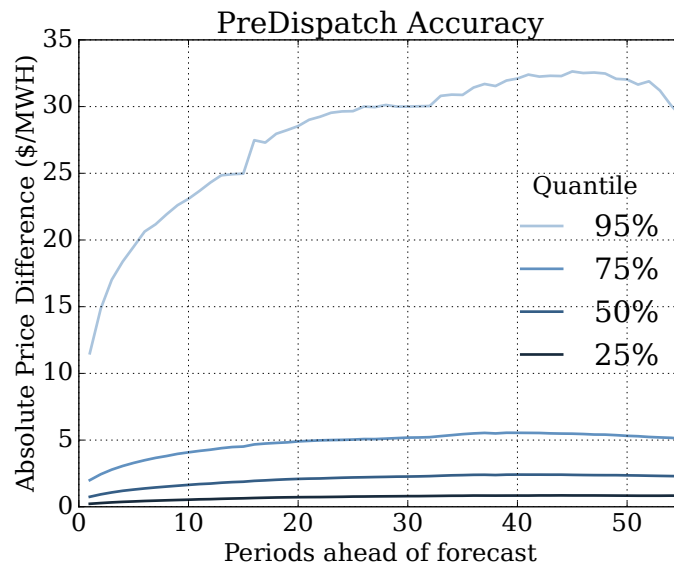


Figure 3.9: Pre-dispatch forecast accuracy. This figure presents the distribution of forecast errors against the number of trading intervals ahead of time that the forecast is made.

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. (2009) found a similar accuracy using the back casting approach, and Connolly et al. (2011) found their prognostic strategy achieved 81% of the optimal strategy profits.

As shown in figure 3.10, increasing the storage improves the realisation of potential arbitrage value, from 70% at 3 hours to over 90% at 8 hours. 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.

While the perfect foresight assumption necessarily provides an upper limit to arbitrage opportunities, 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.

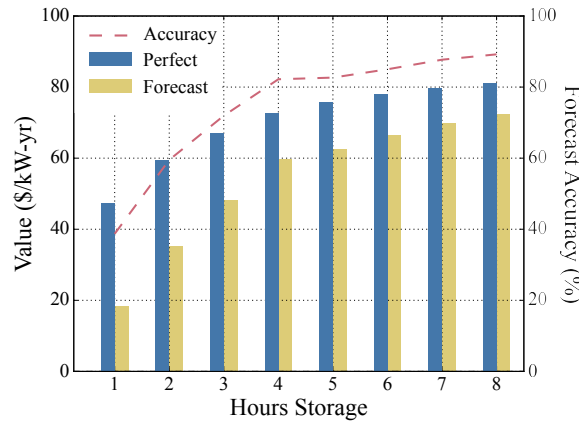


Figure 3.10: Forecast vs Perfect Foresight for FY 2013-14. Value comparison (\$/kW-yr, left hand axis) and accuracy (% , right hand axis)

3.5 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, (Productivity Commission 2013).

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 (Anderson, Hu, and Winchester 2007). Currently, any new OCGT capacity would be financed through the sale of cap contracts, (and conversely, OCGT's are a major seller of cap contracts⁶). Given

⁶Legacy hydro-generators are also significant providers of cap contracts in Australia.

that storage provides similar flexibility and capacity to OCGTs, is similarly dependent on and exposed to extreme price events (see figure 3.8), 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) (Australian Energy Regulator 2009). 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. However storage technologies may face some challenges selling caps, as they cannot run indefinitely like peak generators. Figure 3.11 shows the current and historic cap prices for the different market regions for first quarter for 2015 (mainly summer months in Australia).

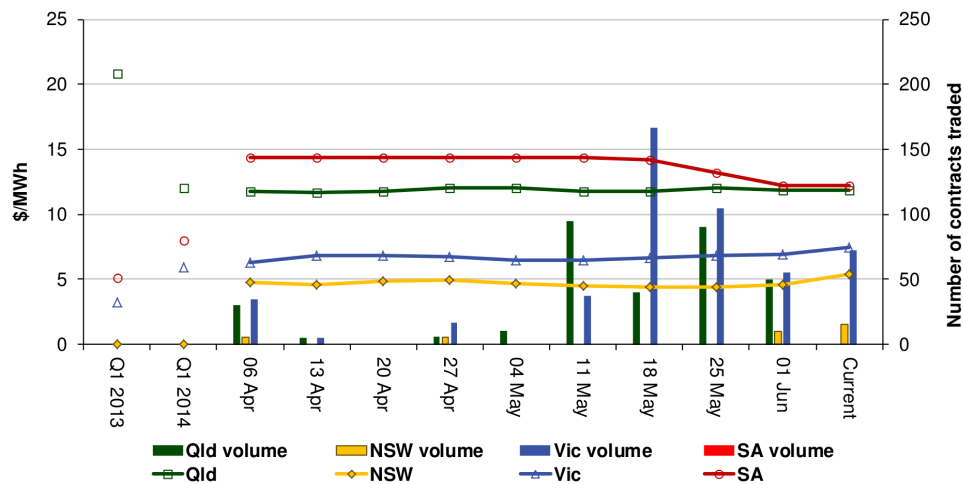


Figure 3.11: Price of Q1 2015 cap contracts over the past 10 weeks (and the past 2 years) [Source: AER Market Snapshot, Aug 2014]

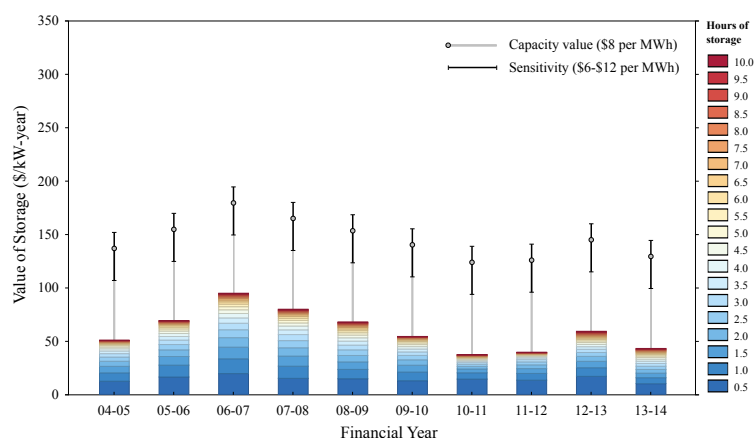


Figure 3.12: Value of contracted storage plant by financial year and storage capacity, for South Australia.

To analyse the effect of the expected hedging contracting and hedging strategies, I 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 is empty), as would occur in the case of an unplanned outage at a fossil fuel generator.

Figure 3.12 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 figure 3.5, the annual revenue profile is considerably more consistent.

3.5.1 Extended case study for South Australia

Chapter 2 identified gas prices and competition issues as significant contributing factors to the recent increases in electricity prices and volatility in South Australia. The case study draws on the result of that analysis and the modelling results from this chapter to consider and compare alternative options to gas in providing capacity.

On the supply side, it is worth noting that there appears no current substantive risk to meeting demand in South Australia, as the installed capacity of gas and distillate generation amounts to 2950 MW, and the interconnection capacity will soon be 850 MW. A recent 'Energy Adequacy Assessment' analysis from AEMO confirmed no breaches of the reliability standard in

any NEM region over the next year, provided gas production facilities remain available (AEMO 2016b).

However, the dependence on gas in times of low wind output, combined with the rising price of domestic gas and limited competition has added a significant cost penalty to South Australian electricity supply. The high prices have opened the opportunity for new supply specifically targeted on low wind output periods⁷. One obvious option for increasing supply in such times is to increase interconnection to other regions. Others include a raft of storage types, including battery, pumped hydro energy storage (PHES), and concentrating solar thermal with storage (CST)⁸.

While transmission upgrades may be worthwhile, detailed analysis is beyond the scope of this study. The South Australian government recently announced a major study into transmission upgrade options⁹ which should provide a detailed insight into the value of additional interconnection capacity.

As argued in this chapter, storage in an energy-only markets typically can exploit arbitrage, but also provide capacity and is a competitor to traditional peaking technologies. In the next section we discuss the potential and limitations, for arbitrage opportunities in the South Australian market, building on the findings of the previous analysis and chapter.

Beyond the ‘Levelised Cost of Energy’

A standard metric used by many studies in assessing the cost of competing generation technologies is the Levelised Cost of Energy (LCOE). The LCOE represents the average cost of producing electricity from a particular technology over its life, given assumptions about how the power station will operate (Bongers 2015). This measure is useful for comparing the cost of *energy* provision by different technologies. However, the LCOE metric does not necessarily capture the *value* of energy provided, or the value of flexible *capacity*.

OCGT’s provide a good example of the limitations of using the LCOE metric. According to the recent Australian Power Generation Technology Study, the LCOE of OCGT is reported

⁷As discussed in chapter 2

⁸It’s also worth noting that all of these approaches could help improve competition, (see section 2.3.3 on Pivotal Supply Index). Both new capacity and increased interconnection decrease the frequency of a generator becoming ‘Pivotal’.

⁹With costs reported in the \$300-\$700 million range

to be in the range of \$158-\$269 (Bongers 2015, page 131), with further exposure to rising gas prices. This is a high LCOE¹⁰ relative to technologies such as wind, and exceeds the average volume weighted wholesale price of electricity on the NEM by 300-500%. Yet OCGT stations do get built for the simple reason that their primary value is not the amount of energy they provide, but rather the provision of *capacity* and flexible supply.

In this section, we compare the cost of capacity of a range of different technologies, including OCGT's. We use a modified LCOE calculation to determine the Levelised Cost of Capacity (LCOC) based on the long-run marginal cost of supplying additional capacity (rather than energy). The LCOC represents the price of capacity required for a project to have a net present value of zero. Many studies have compared the LCOC of various energy storage technologies (Connolly et al. 2011; Electric Power Research Institute 2013, 2011), including some that specifically looked at the value of storage in the South Australian electricity market. More details on the LCOC equation calculations used here can be found in Appendix C.

This approach is analogous to considering what contract price would be needed to finance a particular storage plant. This is in contrast to other analysis that estimate the value storage by making different assumptions around future contract value.

In this case study I assume the various technologies have sold cap contracts at \$300/MWh (see section 2.1.2 for details on cap contracting). Thus for prices at and above \$300, the technology only receives \$300/MWh (in exchange for cap contract revenue). A penalty of the spot price minus \$300/MWh is assumed for any periods where the price is above \$300/MWh but the technology is not available as may occur, for example, where storage levels have been exhausted. A gas generator is assumed to be inexhaustible and able to respond to any price event.

For prices below \$300/MWh, the storage technologies can either arbitrage in the case of PHES and battery storage, or sell electricity at the spot price, in the case of CST. This is an additional revenue stream that is not available to an OCGT gas *peaker* that would not normally be expected to generate at prices below \$300/MWh¹¹. In determining the LCOC, the arbitrage or energy value for these technologies is also taken into account.

¹⁰The LCOE for OCGT is comparable for example to current estimates for solar thermal that to date has not been competitive even with financing incentives such as the RET.

¹¹An OCGT can make additional margin operating above their marginal cost of production, but below \$300 per MWh. However, the fixed start up and shutdown costs (and associated maintenance cycles) mean that this is relatively uncommon.

Storage only technologies: PHES and Battery Storage

This analysis explicitly includes an estimation of the arbitrage value, as distinct from the capacity value, for arbitrage below \$300/MWh. In addition we only consider up to 6 hours of storage, as the previous analysis suggested there was not much additional value beyond that (see figure 3.7). Only PHES and lithium-ion battery technology is analysed, and cost data for both PHES and lithium ion technologies is used from Lazard's Levelised Cost of Storage Analysis (Lazard 2015)¹². Two configurations for lithium ion technology were selected (2 hours and 6 hours) and one configuration of pumped hydro (see appendix C for more details on the input assumptions in the LCOC calculations).

Two different LCOCs 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. Figure 3.13 illustrates the three different LCOCs. As can be seen, PHES may be competitive with a new OCGT under the right conditions.

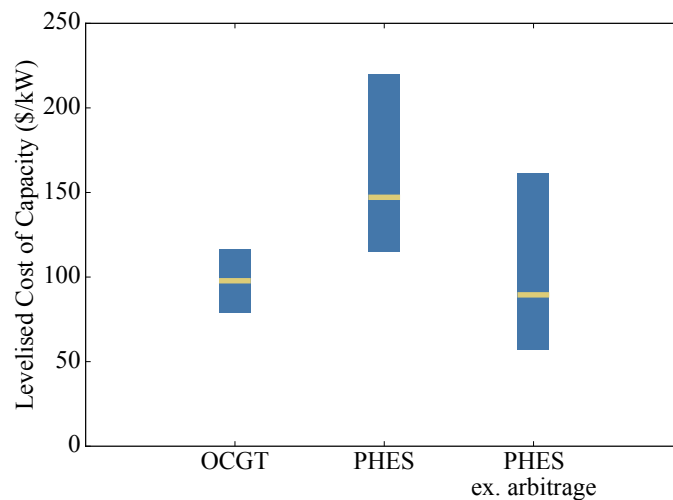


Figure 3.13: Levelised cost of capacity for an OCGT, a PHES and a PHES after taking into account the sub \$300 arbitrage value

¹²A USD to AUD exchange rate of 1.33 (July 2016) was used for this analysis

Energy technologies: OCGT and CST

Technology costs for OCGT and CST were drawn from the 2015 Australian Power Generation Technology Report (Bongers 2015). Similar to storage options, we consider CST with 6 hours of storage. This differs markedly from a configuration with 15 hours of storage, and 50 MW dispatch capacity, recently determined by Alinta to be uneconomical. CST also produces energy. We value the energy based on the futures price of peak energy in South Australia¹³, albeit with the capacity value deducted to avoid double counting extreme price events.

Figure 3.14 illustrates the LCOC for all the technologies considered (both storage and energy technologies). The current value of capacity based on South Australian futures cap of \$20¹⁴ is illustrated by a red line, suggesting at these prices several technologies are economically viable. The wide range of costs largely reflects the uncertainty in the capital cost for the technologies.

One important consideration is missing from this analysis: only CST is producing significant

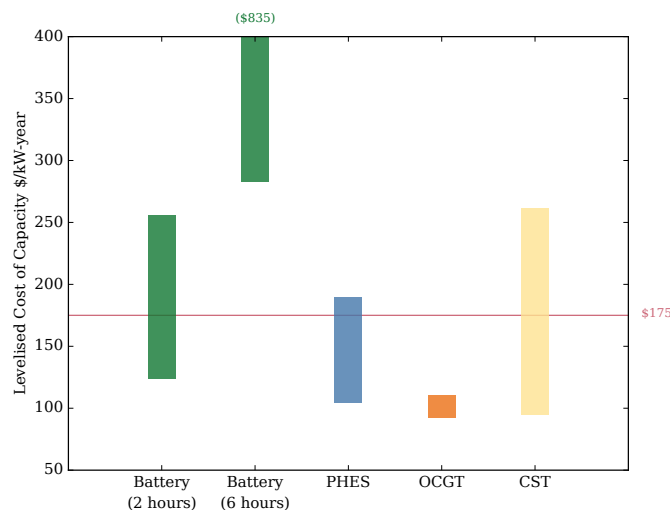


Figure 3.14: This figure compares the Levelised cost of Capacity (LCOC) for the technologies considered. The LCOC value represents the annual revenue required per kW of capacity for the technology to be economically viable (the data and assumptions can be found in appendix C). The red line shows the value of a \$20 cap contract (in \$/kW-year). Technologies that fall below this line would be economically viable at this price.

¹³Current peak futures strip prices for South Australia currently range between \$110 and \$120 out to FY19 (see <https://www.asxenergy.com.au/futures.au>). Note that the Q1 2017 price was \$130 at the time of writing.

¹⁴Current cap strip prices range between \$14 and \$26. Q1 2017 cap prices are as high as \$33 (see <https://www.asxenergy.com.au/futures.au>)

volumes of additional energy¹⁵. Both pumped hydro and batteries will draw additional energy from the grid, since their round trip efficiencies are less than 100%. As such, CST would further displace gas or other generation in the NEM, as well as contributing to emissions reductions. OCGT and other storage technologies will increase emissions, based on the current energy mix. In addition, both CST and storage technologies help alleviate competitive pressures. Peak generation such as OCGT would only offer competitive supply at high prices, whereas CST and storage technologies can increase competition in periods less than \$300 (though arbitrage and energy supply respectively).

3.6 Discussion and Conclusions

Our analysis illustrates that there is value in bulk energy services (including capacity value), however there is currently little marginal value in extending storage capacity beyond six hours in the South Australian market region. The analysis suggests that having bulk energy storage capacity (as has been considered in other studies (AEMO 2013a) 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, this 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 that 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

¹⁵The OCGT will produce small volumes of energy

Sioshansi et al. (2009), 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 the 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 minute dispatch intervals, with both the ERCOT and SPP system recently becoming fast markets (Riesz, Gilmore, and Hindsberger 2013). In these cases, the results are directly relevant.

In markets with alternative designs, these results provide a useful proxy measure of capacity value (beyond energy arbitrage). As discussed in Riesz, Gilmore, and Hindsberger (2013) fast markets are a more efficient approach than others, such as regulation reserves. These results may therefore be considered as an 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. This 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 OCGT's.

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.

Storage opportunities in 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) is 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, if renewable energy generation is increased to meet mandated targets, with a corresponding rationalisation of the emission intensive generation, and/or increasing gas the price outlook for storage may improve. 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 (McConnell et al. 2013; Forrest and MacGill 2013; Sensfuss, Genoese, and Ragwitz 2007), will likely increase the arbitrage opportunities in the below \$300 price range, further increasing the value of storage beyond the capacity value.

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. (2009) 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% (Sioshansi et al. 2009).

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 (Sioshansi et al. 2009). Further work considering the impact dynamic pricing has on the arbitrage opportunity and welfare effects 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 questions about the best ownership structure for storage technologies, as identified in analysis from the U.S. (Sioshansi et al. 2009; Sioshansi 2010). 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 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 over-use storage (Sioshansi 2010).

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 insights 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 on 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.

Chapter 4

Fast markets, and the value of aligning settlement and dispatch

4.1 Introduction

Electricity market design has a significant impact on the efficient scheduling and operation of power systems. As the penetration of variable generation increases, market structure and generation scheduling rules become even more important to ensure efficient generation utilisation. Of significance, market design reforms that facilitate the integration of variable generation also improve the efficiency and operation *without* variable generation (Riesz, Gilmore, and Hindsberger 2013).

In this context, this chapter examines the benefits of moving the NEM to a so-called ‘fast market’¹. The NEM currently makes use of short (5-minute) *dispatch intervals* for scheduling and dispatch, which can be considered ‘fast’. However, the 5-minute price for each dispatch interval is averaged over the *trading interval* (30 minutes) to determine the settlement price, which is the financially relevant interval for participants. In this section I argue that this process renders the 5-minute price signal impotent, and counteracts several potential benefits of fast dispatch, which are particularly relevant to renewable technologies.

¹This analysis also contributed to the AEMC’s “*Five Minute Settlement rule change request*”.

This chapter begins with a general overview of the benefits of ‘fast markets’ to the dispatch process. I begin by examining the specific implications of dispatching against a 5-minute price, while settling on the averaged 30-minute price (the ‘5-30 problem’). This includes an illustration of some of the sub-economic outcomes and perverse incentives created by the misalignment of dispatch and settlement periods, along with an appraisal of the costs. In this section I also describe how the process conceptually works against the benefits of fast dispatch, via the impact on flexible generation.

To explore this concept further, a ‘fast market’ in the South Australian region is modelled in the next section, expanding on the model developed in chapter 3. The modelling compares the value of storage and the optimal dispatch under differing settlement and dispatch regimes, and under both ‘perfect foresight’ and forecast conditions. The chapter finishes with discussion and conclusions.

4.2 ‘Fast Markets’

‘Fast markets’ have emerged as a particularly relevant design consideration for electricity markets. The International Energy Agency (IEA) recently released ‘*Re-powering Markets: Market design and regulation during the transition to low-carbon power systems*’ (IEA 2016), the first official publication from the IEA that analyses the electricity market framework for low-carbon power systems. The IEA report describes short term markets and increasing price resolution as ‘pivotal’ (see IEA 2016, Chapter 3: ‘Short-term markets’, page 73).

Fast markets can be loosely defined as markets with short dispatch intervals (for example 5 minutes). The value of short dispatch intervals is described in ‘*Market Design for the Integration of Variable Renewables*’ (Riesz, Gilmore, and Hindsberger 2013, page 764):

Short dispatch intervals allow more frequent redispatch of the whole system, enabling deviations to be dealt with by adjustment of every market participant in the system as appropriate. Long dispatch intervals mean that deviations in load and variable generation away from the central set point for the interval for be significantly larger, requiring larger regulation services.

Similarly, a report prepared by the U.S. Department of Energy’s National Renewable Energy Laboratory (Milligan and Kirby 2010) emphasises the importance of fast energy markets. They argue that short dispatch intervals and sub-hourly energy markets provide the right economic signals for conventional generators and flexible generators to respond to short-term fluctuations in load and variable generation. Indeed this report strongly argues that long temporal resolution pricing increases costs and “*hobbles*” the generation fleet (Milligan and Kirby 2010, page 16):

Scheduling rules that restrict generators to hourly movements artificially hobble the conventional generation fleet, resulting in lost opportunities for those generators and increased costs for all.

While the NEM does have sub-hourly (5 minute) dispatch intervals, the current process of averaging prices across the trading intervals ‘hobbles’ the generation fleet, by *not* providing the full incentives and price signals of a ‘fast market’. As discussed further in the following sections, this creates sub-economic outcomes and perverse incentives such as rebidding.

4.3 The ‘5-30 problem’

4.3.1 Allocative inefficiency of average pricing

The current arrangements can result in sub-economic outcomes, because they allow misalignment between the marginal cost of supply, as expressed in the dispatch price, and the trading price (figure 4.1a). Where the marginal cost of supply is *below* the trading price, consumption and production will fall below the market equilibrium (scenario 1, figure 4.1a). Where the marginal cost of supply is *above* the trading price consumption and production is above the market equilibrium (scenario 2, figure 4.1b)

Importantly, these sub-economic outcomes are not dependant on *when* the differences occur within the interval, but only *if* there is a difference. A significant price spike in any one dispatch interval will result in a loss of economic welfare.

For most trading intervals, the difference between dispatch prices and trading price is relatively small, so any economic welfare costs are minimal. Table 4.1 shows the distribution of maximum pricing differences for the mainland market regions in 2015. For example, 50% of the

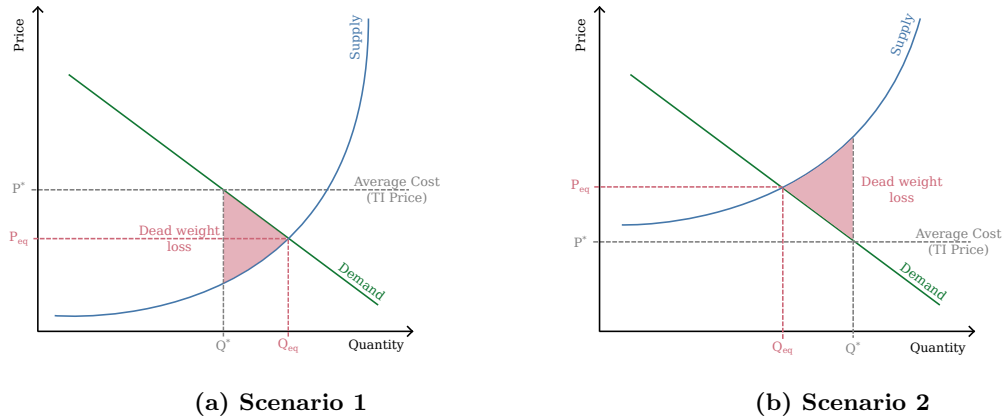


Figure 4.1: Allocative inefficiency resulting from misalignment of trading and dispatch intervals. Where the marginal cost of supply is below the average price (trading price), consumption and production are below the equilibrium price (scenario 1). Where the marginal cost of supply (dispatch price) is above the average price (trading price) consumption and production are above the equilibrium price (scenario 2).

time, the maximum price difference between trading intervals and dispatch intervals is less than \$2.10 in NSW, and less than 1% of time, the price difference is greater than \$194.30 in SA.

However, due to the high price cap in the NEM, in extreme cases the differences can be very significant with very high settlement prices. Importantly, the proportion of market revenue that occurs in these extreme trading intervals can be high. Table 4.2 shows the proportion of market revenue generated by trading intervals categorised by the price differences described in table 4.1. For example, in SA in 2015 intervals with a price difference greater than \$194.30 comprise less than 1%, however they represent almost 20% of the total wholesale revenue for the SA market in that year. For QLD, the revenue proportion was 29.63%, representing some \$926 million².

This analysis is intended to highlight the contribution these intervals make to the overall turnover in the market. While these intra-interval spikes may have been efficient responses, the fact the prices are ‘smeared’ over a trading interval and that these trading intervals contribute disproportionately to annual turnover warrants further investigation, and suggest that significant gains in efficiency may stem from aligning settlement with dispatch.

²As discussed later in section 4.3.2, some fraction of this is likely to be a function of rebidding practices.

Table 4.1: Distribution of price differences between trading and dispatch intervals, 2015

	Percentage of Trading Intervals			
	50%	10%	5%	1%
NSW	\$2.10	\$6.96	\$11.00	\$116.73
QLD	\$2.34	\$8.75	\$27.18	\$194.83
SA	\$2.79	\$11.52	\$27.39	\$194.30
VIC	\$2.19	\$8.85	\$15.42	\$100.91

Table 4.2: Proportion of market revenue in trading intervals with price differences

	Percentage of Trading Intervals			
	50%	10%	5%	1%
NSW	58.31%	22.66%	17.03%	7.23%
QLD	70.60%	45.50%	40.72%	29.63%
SA	64.82%	35.84%	29.58%	19.21%
VIC	58.56%	19.12%	13.42%	5.38%

4.3.2 Perverse incentives: rebidding

The 30-minute settlement allows some perverse incentives relating to bidding behaviour. Specifically, it fosters conditions ripe for gaming or other market distortions, through the process of ‘rebidding’.

In the NEM, participants are able to “rebid” their capacity into the market up until the start of the next dispatch interval, by changing the amount of capacity offered to the market in a particular price band. This allows rapid response to changing market conditions and more efficient dispatch, improving the dynamic efficiency of the system (Riesz 2013).

These rules also create a series of perverse incentives, resulting from the fact that rebidding can occur *within* a 30-minute trading interval when information about the clearing price is already known. This has been acknowledged by the Australian Energy Market Commission in the Bidding in Good Faith rule change: *‘the incentives on some generators to engage in strategic late rebidding were exacerbated by the mismatch between dispatch and settlement’* (AEMC 2016, page 11). I argue that rebidding is largely an issue *because* of the mismatch between dispatch and settlement, and the ability to retrospectively impact prices. The incentive for late rebidding would be greatly reduced if the mismatch did not exist. In addition, I show the costs imposed by late rebidding are significant.

Figures 4.2 and 4.3 illustrate the distribution of price spikes in QLD in 2008-2009 and 2014-2015 respectively. As can be seen, the distribution of price spikes within trading intervals is markedly different between these time periods. There is no fundamental reason why price spikes should occur later in a trading interval: in theory they should be randomly distributed, as is seen in 2008 and 2009. Figure 4.4 further illustrates the evolution of the difference between the number of price spikes in the last interval relative to the number in the remaining intervals.

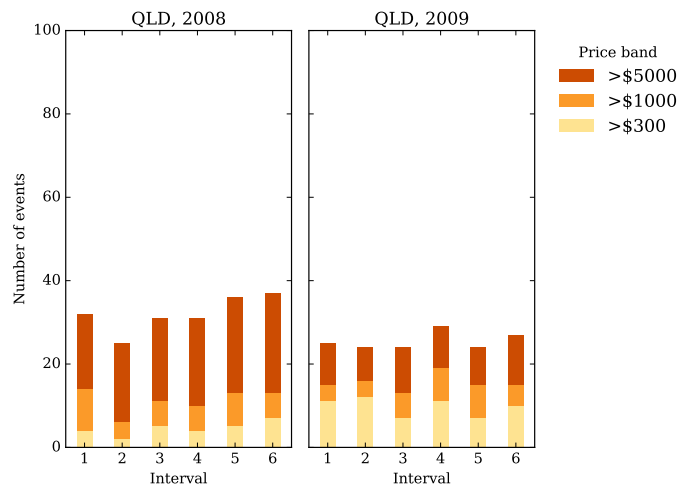


Figure 4.2: Distribution of dispatch prices above \$300 with trading intervals, 2008-2009. The dispatch prices are more or less randomly distributed, as should be expected in an efficient market.

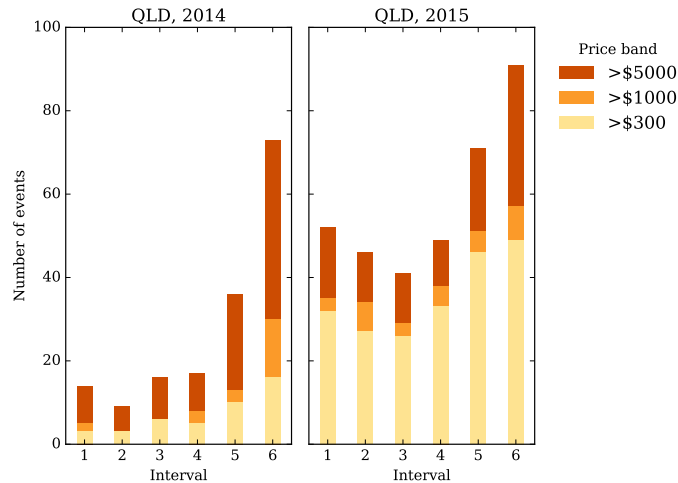


Figure 4.3: Distribution of dispatch prices with trading intervals, 2014-2015. In this case, the dispatch prices are highly skewed to the final dispatch interval. There is no fundamental reason why this should occur.



Figure 4.4: Ratio of price events that occur in the last dispatch interval to events in remaining dispatch interval in Queensland. The prevalence of price spikes in the last dispatch interval increased significantly between 2012 and 2014

Such price spikes come at significant cost. Analysis of Queensland dispatch and settlement data suggest that in 2015, price spikes in the last 5 minutes of an interval added \$250 million to the turnover through the wholesale market (see appendix D.2, page 179 for further details).

The Bidding in Good faith rule changes were introduced in part to ‘*lead to more efficient wholesale price outcomes*’ (AEMC 2015b, page i). However, they do not remove the fundamental mismatch that creates the incentives for this behaviour in the first place.

4.3.3 Flexible generation incentives

Thirty minute settlement also creates perverse (dis)incentives for flexible generation, such as open cycle gas turbines, pumped hydro, or battery technologies, through inefficient utilisation of generation capacity, under recovery of fixed costs and problematic hedging arrangements.

As outlined in the following sections, this can be illustrated by considering an example 30MW flexible generator with marginal costs of \$300/MWh, that has perfect response. Whilst the perfect response assumption makes for a somewhat idealised case, it is noted that some technologies are very highly responsive from a ‘warm’ start³ (Table 4.3). For example, hydro plants are typically able to ramp 30MW in 6 seconds, whilst OCGTs are able to ramp 30MW in 18 second.

³Thermal technologies also have start-up times if they are offline (‘cold’). Typically thermal plants follow a unique start up profile (‘fast start inflexibility profile’) before they are able to ramp at their maximum rate.

Table 4.3: Rate of Change (RoC) by technology, as offered to the NEM, based on the offers placed by generators in the NEM. For thermal technologies, these figures are not indicative of ‘cold start’ times.

Technology	ROCUP (MW/Min)		ROCDOWN (MW/Min)	
	Maximum	Average	Maximum	Average
Brown Coal	118	3.73	350	3.77
Black Coal	350	3.89	350	3.66
Gas (OCGT)	100	10.91	100	8.61
Gas (CCGT)	43	10.09	43	7.80
Gas (Steam)	57	6.23	50	5.32
Distillate	100	5.82	100	5.82
Hydro	300	31.81	200	24.15

Inefficient utilisation

Figure 4.5 illustrates the rational responses to a price spike for optimal operation responding to either the dispatch price signal (middle panel) or the trading interval pricing (lower panel). The price spike is assumed to occur in the second dispatch period of the given trading interval. The yellow line represents the ‘running average’ dispatch interval price for a given trading interval.

As illustrated in figure 4.5, the optimal operating profiles differ for the dispatch and trading responses. Once the price spike has occurred, the rational trading response is to continue generating for the remainder of the trading interval, which is manifestly inefficient. The trading response recovers only \$25,650 or 5/6^{ths} of the \$34,000 optimal dispatch response. The later the anomalous dispatch period occurs in the trading interval the greater the disparity. For example, figure 4.6, illustrates the case where the anomaly dispatch interval is the fifth interval with the generator responding to the trading price. While over producing, the generators revenue is reduced to \$10,250, highlighting the significant risk for a flexible generator trying to recover fixed costs in the trading response mode. More generally the discrepancy scales as

$$R_D \frac{D_{int} - i - 1}{D_{int}}$$

where R_D is the revenue for optimal dispatch interval response, D_{int} is the number of dispatch intervals in the trading period and i is the relevant dispatch interval for which a rational fast response is required.

In addition, this has implications for how flexible generators (such as OCGT’s) arrange finance and manage risks. Typically, such generators sell cap contracts (See AEMC 2012, for more details

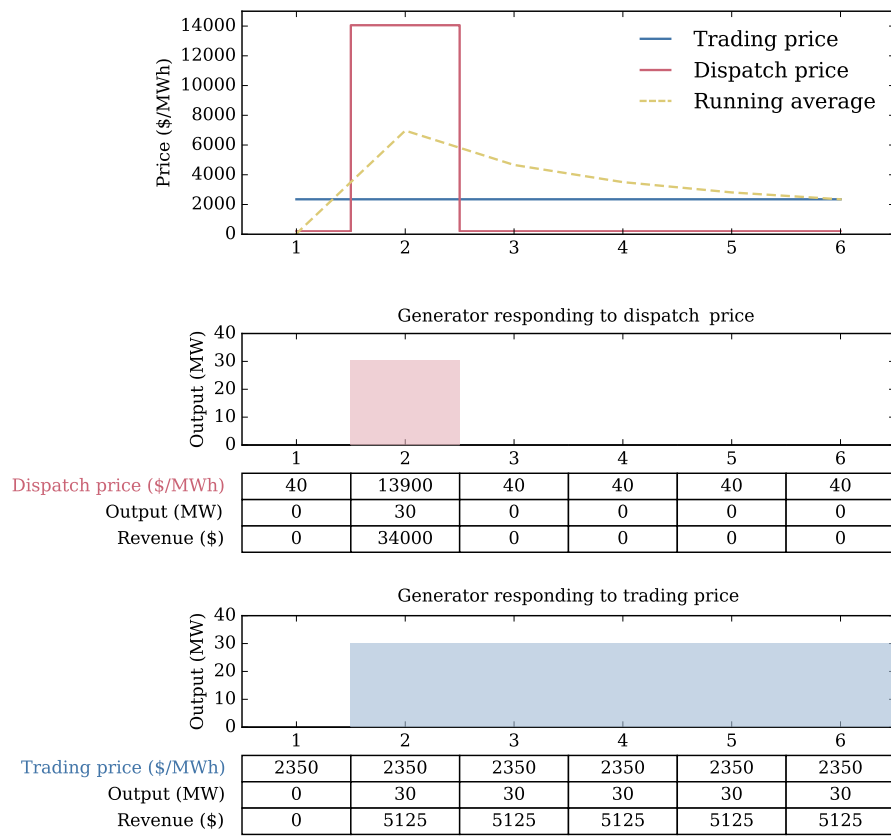


Figure 4.5: Comparison of the optimal operation of a generator facing dispatch with that of a generator facing the averaged trading interval pricing, where a dispatch price spike has occurred early in the trading period. The generator responding to the trading price incurs more costs than would otherwise be required, and recovers less revenue to cover fixed costs.

on typical cap contract arrangements). In the situation presented figure 4.6, the generator would be liable to pay \$30,750 to the cap contract counter party⁴, presenting a significant risk and liability to the generator. This problem would not occur, if the *dispatch* price was hedged with a similar instrument.

In combination, these factors provide a barrier to entry by disincentivising fast response generators participation in the market.

⁴ Assuming a \$300 cap contract

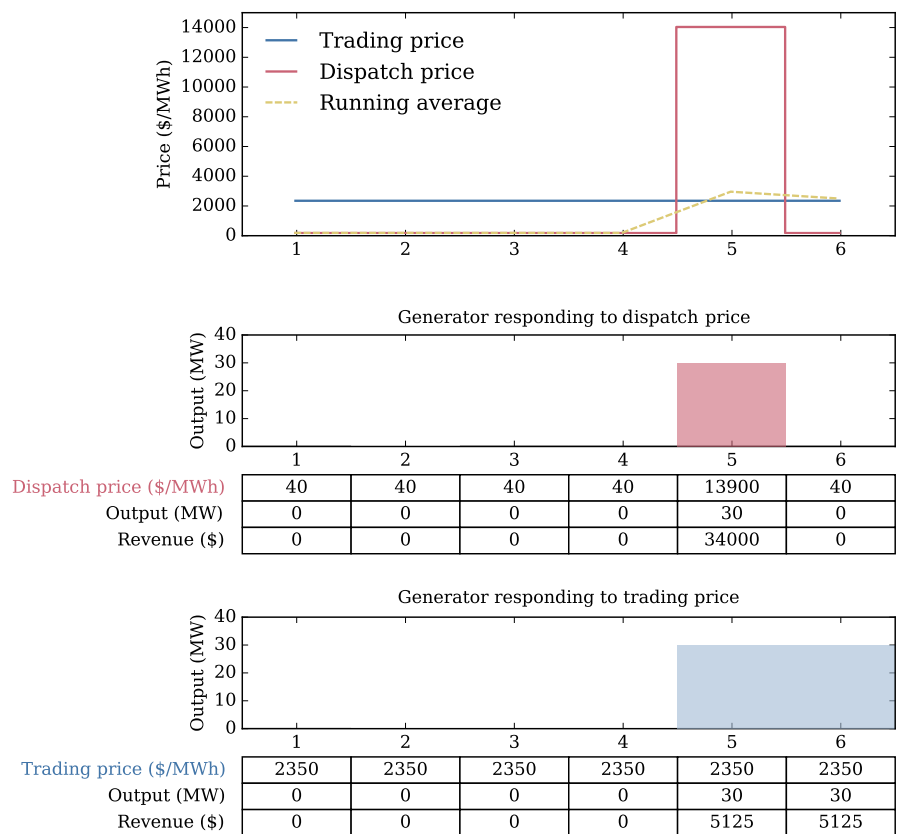


Figure 4.6: Comparison of the optimal operation of a generators facing dispatch with that of a a generator facing the averaged trading interval pricing, where a dispatch price spike has occurred early in the trading period. The generator would not recover enough revenue to cover liabilities incurred by standard contracts and risk-management strategies.

4.4 Modelling a ‘fast market’ in South Australia and the NEM

This analysis further considers the impact of dispatch and settlement alignment for fast response storage technologies. Within storage technologies, the results are technologically agnostic and are relevant for pumped hydro energy storage or any number of different battery chemistry storage options. Some elements of the analysis may be applicable beyond storage technologies, and could be relevant for other fast response generators (for example, diesel gensets) or demand-side solutions.

The analysis extends previous modelling investigating the value of storage in wholesale electricity markets (optimal dispatch illustrated below, see chapter 3 for more details). This analysis uses the ‘*small device*’ assumption, where by the device is considered to be too small to have a material impact on prices. The figure over page illustrates a sample output of the model.

I focus this analysis on the South Australian market region, as is it the most more volatile

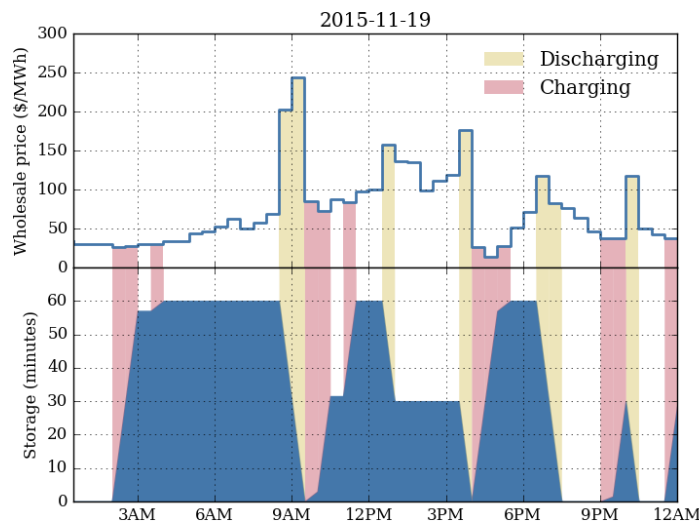


Figure 4.7: This figure illustrates the optimal operation of a storage device for a particular day in the South Australian electricity market region. This scenario investigates a device with 1 hour of storage, settled on the half an hour trading price, with perfect foresight of prices. Trading intervals where the storage device is charging are highlighted in red, while intervals where the device is discharging are highlighted in yellow. The storage level, measured in minutes of energy storage at the rated output is shown in blue.

Table 4.4: Trading price and dispatch statistics for South Australia for FY15 and FY16

	Trading Interval		Dispatch Interval	
	FY15	FY16	FY15	FY16
VWP	\$42.35	\$67.16	\$42.49	\$67.36
\$300	49	185	201	1437
\$1,000	37	48	49	88
\$5,000	0	1	38	51

region in the NEM, (see chapter 3 for more details). In particular, I analyse price outcomes from FY15 and FY16. The characteristics of these two years differ, as illustrated in Table 4.4. FY15 represents a low volatility year, whilst FY16 represents a year with high volatility with substantially more $\geq \$300$ price events. This is indicated by the number of high price events on both the 5-minute dispatch intervals and the 30-minute trading intervals.

In this section I first describe the model, and how it was extended to undertake this analysis. Then I present a description of the scenarios considered. This includes a brief description of the effective incentives provided under the current regime of 5-minute dispatch and 30-minute settlement. This is followed by analysis of the results and then a case study that considers the impacts of the analysis on a specific technology, lithium ion battery storage. In particular this provides insight into how the value of storage changes under differing dispatch and settlement regimes, and how this would flow through to changes in the price of ‘cap-contracts’ offered by storage technologies.

4.4.1 Model description

This problem is formulated as a maximisation problem (equation 4.1). The objective is to maximise revenue, calculated from charging and discharging rates and the price for a given interval (P_i), subject to a variety of constraints. The charging rate (Q_{c_i}) and discharging rate (Q_{d_i}) for each interval (variables 4.7) are the decisions variables that are optimised in this problem.

The main constraint is the energy balance constraint (equation 4.6), which ensures the energy stored at the end of an interval (E_i) is the sum of the energy stored at the beginning of the interval (E_{i-1}) and any changes resulting from charging (Q_{c_i}) or discharging (Q_{d_i}) over the interval. The energy balance equation also takes into account the efficiency of charging (η_c) and discharging

(η_d) , which represent the losses that occur during the process. The other constraints (equation 4.2) simply ensure the physical constraints of the storage device (e.g. maximum charging and discharging rates, and maximum storage amount) are not violated.

The price (P_i) and number of intervals optimised (n) over which the optimisation is performed depends on the scenarios analysed (see section 4.4.2). For ‘*perfect foresight*’ scenarios, the price for all intervals is assumed to be known in advance and all intervals are optimised at once. For forecast scenarios the price is only known for a certain number of periods ahead of time. In these scenarios, all forecast data known at a particular point in time are used to optimise operation for that point in time. Each interval is successively optimised on a rolling basis, based on the optimal results from the previous trading interval, and the known forecast data for the current interval.

The model is mathematically formulated as follows:

Maximise:

$$\sum_{i=1}^n P_i \times (Q_{d_i} - Q_{c_i}) \quad (4.1)$$

Subject to:

$$0 \leq Q_{d_i} \leq Q_{d_{max}} \quad (4.2)$$

$$0 \leq Q_{c_i} \leq Q_{c_{max}} \quad (4.3)$$

$$0 \leq E_i \leq E_{max} \quad (4.4)$$

$$(4.5)$$

$$E_{i-1} + \eta_c Q_{c_i} - \eta_d Q_{d_i} = E_i \quad (4.6)$$

Where:

$$Q_{c_i} = \text{charge rate at interval } i \quad (4.7)$$

$$Q_{d_i} = \text{discharge rate for interval } i \quad (4.8)$$

$$P_i = \text{price at interval } i \quad (4.9)$$

$$E_i = \text{total energy stored at interval } i \quad (4.10)$$

$$E_{max} = \text{maximum energy storage} \quad (4.11)$$

$$Q_{c_{max}} = \text{maximum charge rate} \quad (4.12)$$

$$Q_{d_{max}} = \text{maximum charge rate} \quad (4.13)$$

$$\eta_c = \text{charging efficiency} \quad (4.14)$$

$$\eta_d = \text{discharging efficiency} \quad (4.15)$$

$$n = \text{number of intervals optimised} \quad (4.16)$$

4.4.2 Simulation scenarios

I considered four major classes of simulation scenarios for analysing the impact of dispatch and settlement alignment. These are described below:

- **Perfect 5/5:** In these scenarios dispatch occurs on a 5-minute timescale, and settlement occurs with respect to the 5-minute prices. Operation is optimised based on the 5-minute prices, which are assumed to be known in advance (*'perfect foresight'*).
- **Perfect 5/30:** These simulation scenarios assume dispatch occurs on a 5-minute basis, but settlement occurs with respect to the 30 minute price. *'Perfect foresight'* of the 30-minute trading interval prices are assumed in this scenario, and operation is optimised based on the 30-minute prices.
- **Forecast 5/5:** Dispatch and settlement are aligned on the 5-minute prices. To capture the uncertainty associated with future prices, these scenarios use forecasts published by AEMO. Both 5-minute price forecasts (for the following hour) and 30-minute price forecasts (until the end of the following trading day) are used in these scenarios. Operation for a given

dispatch interval is based on the 5-minute price and all the forecast data known at the time.

- **Forecast 5/30:** Dispatch occurs on a 5-minute basis, but settlement occurs with respect to the 30-minute price. As above, both 5-minute price forecasts (for the following hour) and 30-minute price forecasts (until the end of the following trading day) are used in these scenarios. However, in this case, operation is optimised on the expected 30 minute price, which is based on both the previous dispatch prices, and the forecast data known at the time. This is particularly relevant for price spikes which are not forecast, which is illustrated below in figure 4.8.

For each of these scenario classes, a range of different parameters were also analysed. This includes a range of round-trip efficiencies, as well as differing amounts of storage (hours). Other scenarios considered a ‘cycling cost’, which acts to limit the amount of charge and discharge cycles that occur. This is relevant for battery storage technologies where high round-trip efficiency (e.g

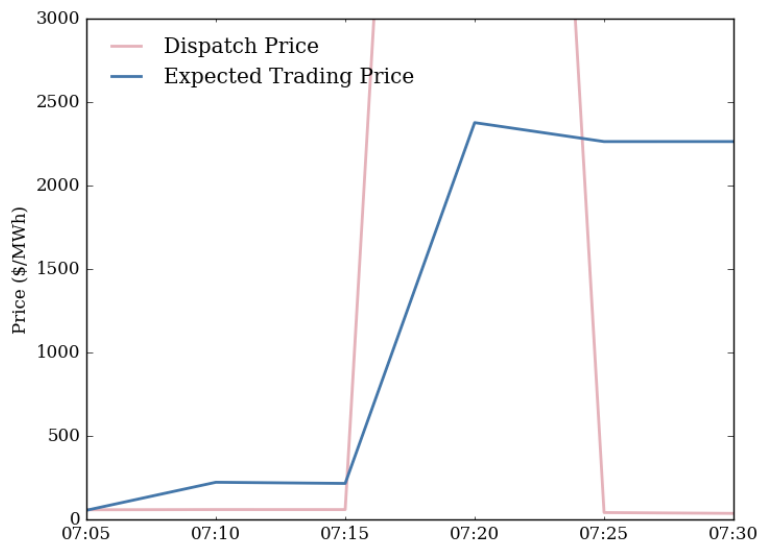


Figure 4.8: This figure illustrates the expected trading price for a 30-minute trading interval with an unanticipated price spike in a 5-minute dispatch interval. The 5-minute dispatch price is shown in red and extends to the market price cap of \$14,000 at 7:20, while the expected 30-minute trading interval at a given time is shown in blue. The trading price is the simple average of the six dispatch prices over the trading interval. As such, the expected trading price at a given time is determined from the actual price in the previous dispatch intervals and the forecast price for the remaining dispatch intervals.

95%) would result in a large number of cycles occurring under optimal operation, which would substantially reduce battery life.

I also considered several forecasting scenarios. In the basic *'forecast only'* scenarios, I only considered operation based on forecast information. As a result, these scenarios cannot account for or plan for price spikes that are not forecast. In other forecast scenarios, some amount of energy was reserved unless the spot price was above a specific threshold, in this case \$1,000/MWh. The amount of energy reserved was varied from the equivalent of 1 dispatch interval (DI) up to 6 DI. This is functionally equivalent to offering the particular number of DI's into the market at \$1,000/MWh.

A range of 1 to 6 DI was considered to reflect the two different settlement intervals analysed (5-minutes and 30-minutes). For example, if one un-forecast price spike occurred under 5-minute settlement, only one DI worth of energy would need to be reserved. Under 30-minute settlement, if one un-forecast price spike occurred in the first 5-minute DI of a trading interval, enough energy for the remainder of the interval would have to be reserved to fully capture the price spike.

4.5 Results

As in chapter 3, the power rating for the storage device 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. As such, the results here are presented in units of dollars per kW per year (\$/kW-year). This represents the value a storage device would be expected to generate over a year per kW of installed capacity, and can be applied to any sized storage device.

In this section I compare the differing outcomes of optimal operation under 30-minute settlement and 5-minute settlement. Specifically, I compare the revenue generated in each case as if a storage device was operated as a 'merchant' plant, paying and receiving spot market prices without any hedging arrangements.

4.5.1 Perfect scenarios

I first test the value of storage under the assumption of ‘perfect foresight’ of electricity prices. A range of configurations were analysed, including but not limited to different amounts of storage and different round-trip efficiencies.

In general, the maximum absolute value generated from a storage device with large amounts of storage (e.g. 6 hours) was unaffected by the length of settlement periods. The amount of storage required (in hours) to achieve this value was, however, different. With 5-minute settlement, the same relative level of value could be extracted with less storage. This is illustrated in figure 4.9.

4.5.2 The impact of forecasting

In this section I consider the impacts of forecasting and forecasting errors. The difference in outcomes and revenues can be very significant, when taking forecasting and forecasting errors into account.

Figure 4.10 shows a particular day where the revenue was different by almost a factor of six. In this forecast case, 1 kW of storage would have generated \$617 of revenue over the course of the day under 5-minute settlement. Optimised with 30 minute settlement, the same 1 kW of

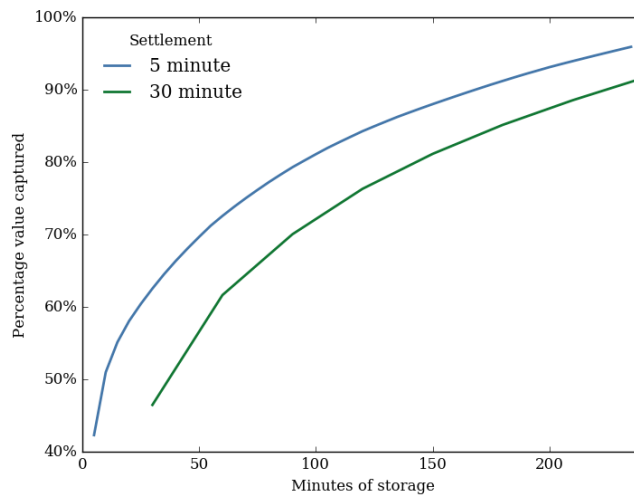


Figure 4.9: This figure shows the relative value captured with different amounts of storage. The relative value is the value extracted relative to the total value possible with 6 hours of storage. As can be seen, less storage is required to extract the same value under 5 minute settlement relative to 30 minute settlement.

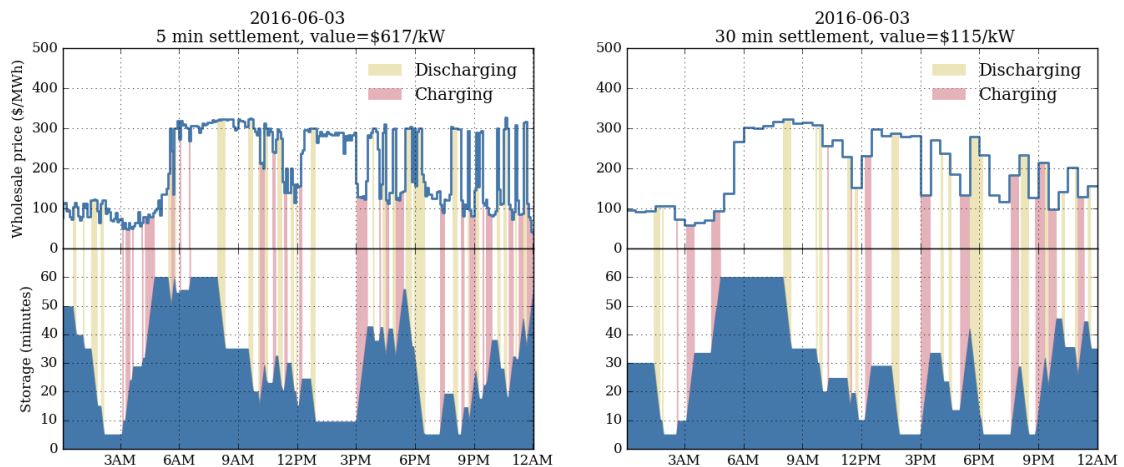


Figure 4.10: These figures show the difference in optimal operating profile under 5 minute settlement and 30 minute settlement. Both these scenarios analyse a storage device with 1 hour of storage, and use forecast data rather than ‘perfect foresight’. This day does not feature price spikes to the market price price cap (\$13,900 for FY16), and yet the difference in revenue outcomes is substantial.

storage would only generate \$115 of revenue.

What is particularly noteworthy about this example is that it does not involve extreme prices. Both trading and dispatch prices remained below \$350 per MWh for the entire day. On another occasion, which included extreme price spikes, the difference in daily revenue was much as much as \$1,370/kW.

Figures 4.11 and 4.12 compare the aggregated value of storage (in \$/kW-yr) under 5-minute settlement and 30-minute settlement for FY15 and FY16. There is a substantial difference in values between the two years, reflecting the differing volatility in these years. More interesting is the difference between the 5-minute and 30-minute settlement values. Across both years, the value of storage under 5 minute settlement is generally 60%–80% higher. In one case (FY15, with 1 DI of energy reserved for prices greater than \$1000), the 5 minute settlement value is 91% greater than the 30-minute settlement value.

When using forecast data, 5 minute settlement also significantly improves the value relative to ‘perfect’ value. Close to 90% of the ‘perfect value’ is captured in FY15 across varying operating strategies, and 80% is captured in FY16. By comparison, only 40%–60% of the ‘perfect’ value is captured under 30 minute settlement.

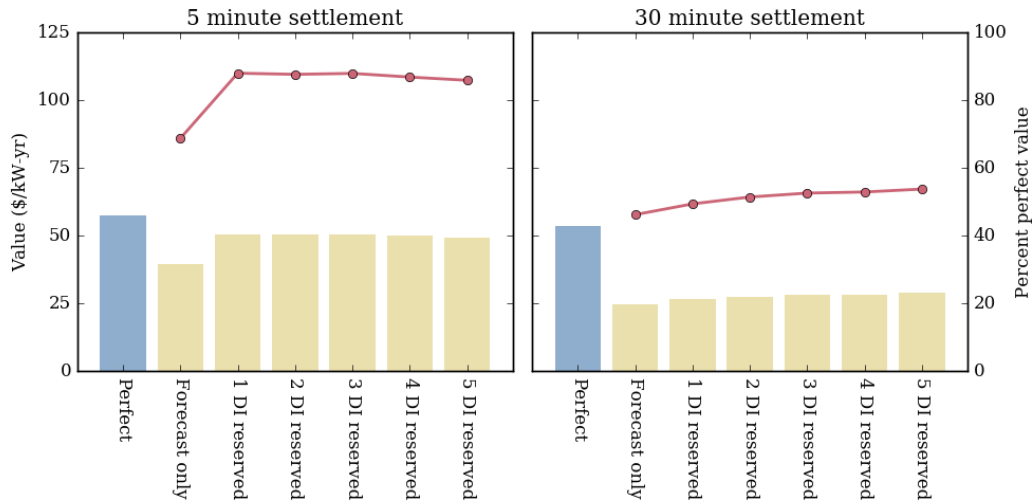


Figure 4.11: These figures compare the value of storage under the two different settlement periods using different operating strategies in FY15 in South Australia. The blue bar shows the value where operations is optimised with 'perfect forecast' of prices. The yellow bars represent the value using forecast data to optimise operation, which incorporates the impact of real world price uncertainty. The red line represents the proportion of 'perfect' value captured by the different forecast scenarios.

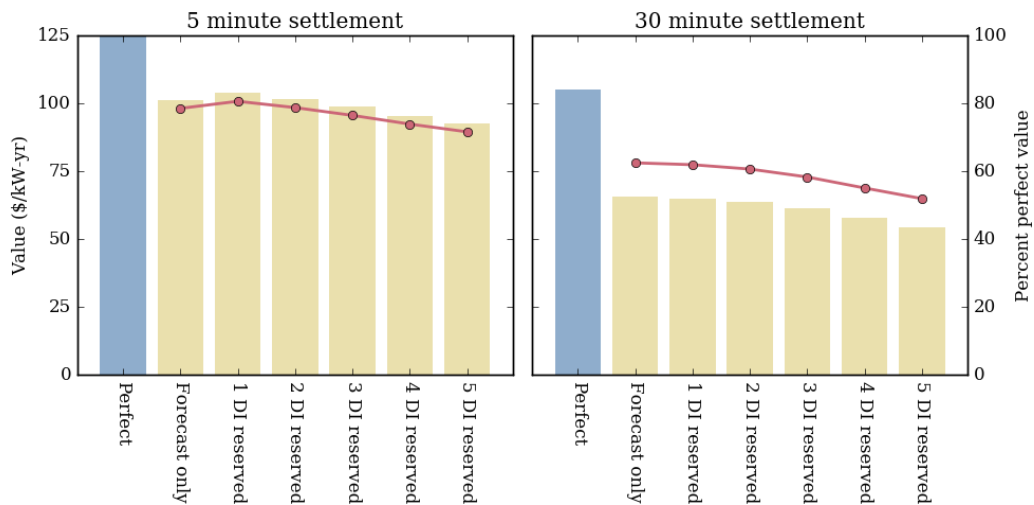


Figure 4.12: These figures compare the value of storage under the two different settlement periods using different operating strategies in FY16 in South Australia. The blue bar shows the value where operations is optimised with 'perfect forecast' of prices. The yellow bars represent the value using forecast data to optimise operation, which incorporates the impact of real world price uncertainty. The red line represents the proportion of 'perfect' value captured by the different forecast scenarios.

4.5.3 Impact on cap contract

Typically, participants in the wholesale market utilise a variety of hedging products to manage the volatility in the wholesale spot market. Given that storage provides similar flexibility and capacity to peak generators, and is similarly dependent on and exposed to extreme price events, they would likely be financed in a similar way, using cap contracts. Here I explore this in more detail.

Generally, the seller of cap 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). In return 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. Importantly, even if they fail to generate when prices are above \$300 and are thus not receiving spot market revenue, they still must compensate the purchaser of the cap contract the difference between \$300 and the spot price.

These typical contracting arrangements affect the value under the 5-minute settlement and 30-minute settlement. There are two components to this. Firstly, there is revenue derived at prices below \$300 dollars, which do not require payments to the contract counter party. Secondly, there are payments to the contract counter party at prices above \$300 price where the generator is not operating and not receiving spot revenue. Here I refer to these as ‘penalty payments’.

Figures 4.13 and 4.14 show the $\leq$ \$300 revenue and penalty payments for FY15 and FY16. As can be seen in figure 4.13, the penalty payments completely wipe out any value that might be delivered from the $\leq$ \$300 opportunities. In FY15 the difference between 5-minute and 30-minute settlement amounts to \$15/kW-year and for FY16 the difference amounts to approximately \$25/kw-yr. The degree to which the difference flows through to actual contract prices in the longer term will depend on the market response, and is beyond the scope of this analysis.

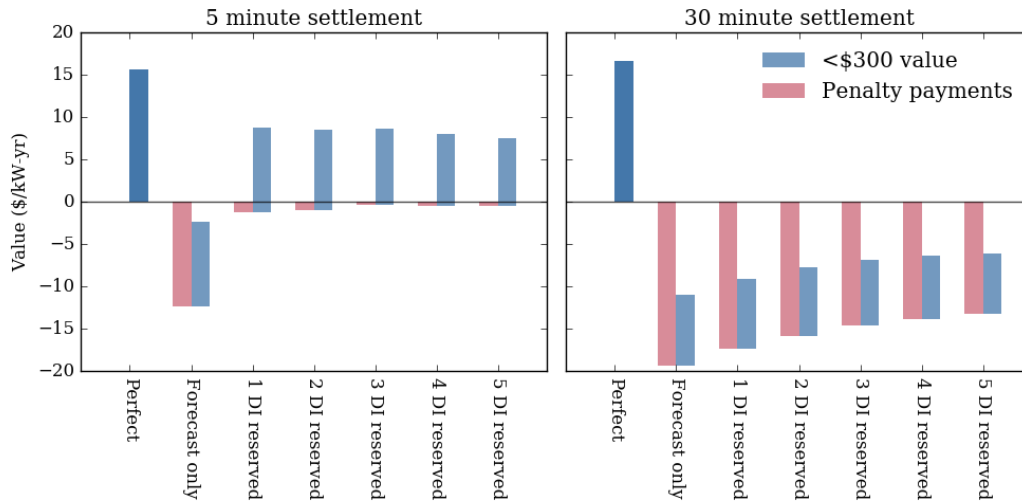


Figure 4.13: This figures shows the $\leq$ \$300 revenues and penalty payments for FY15. The blue bars represent the $\leq$ \$300 value and the red bars represent the 'penalty payments' that would occur under the cap contract. The $\leq$ \$300 revenue and penalty payments are aggregated such that the top of the blue bar represents the total impact of these two cash flows.

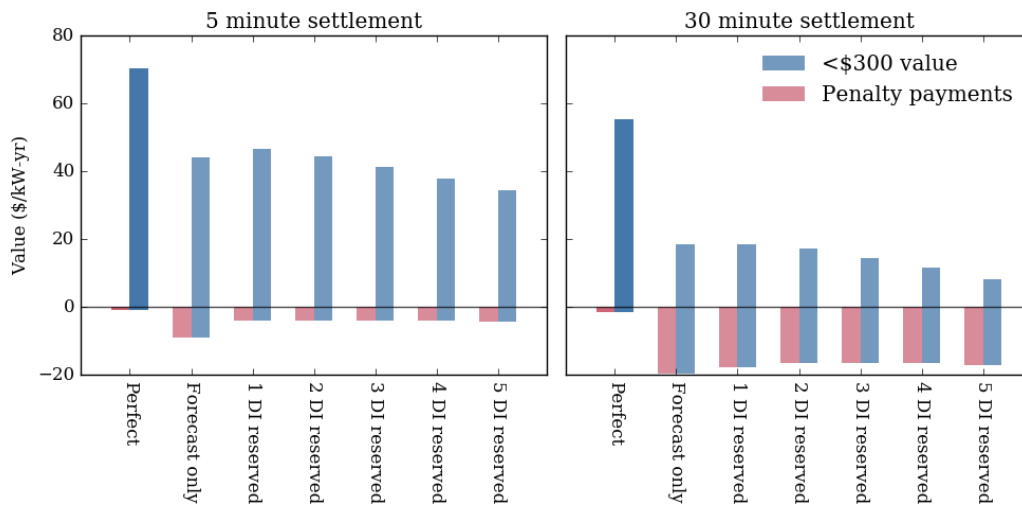


Figure 4.14: This figure shows the $\leq$ \$300 revenues and penalty payments for FY16. The blue bars represent the $\leq$ \$300 value and the red bars represent the 'penalty payments' that would occur under the cap contract. The $\leq$ \$300 revenue and penalty payments are aggregated such that the top of the blue bar represents the total impact of these two cash flows.

4.6 Case study: Lithium battery storage

In this case study I calculate the impact that these results would have on the ‘cost of capacity’ of a lithium-ion battery. This measure is analogous to the Levelised Cost of Energy (LCOE) and represents the revenue required for each unit of capacity for the project to be financially viable. This effectively reflects what cap contract price would be needed to finance the battery project, and is similar to the approach used in case study in chapter 3⁵.

The input assumptions on battery costs are taken from Lazard (2015), and can be found in table 4.5 below. I analysed the lithium battery costs for peaker replacement batteries, and assumed 10% discount rate and a 20-year economic life, with capital replacement occurring in the 10th year. Another scenario where the economic life is assumed to be only 5 years (with no replacement costs) is also included in appendix D.1.

In calculating the cost of capacity, I considered the additional revenue that is generated for prices below \$300. In addition, I take into account the penalty payments that a cap provider would have to make for occasions where the price is above \$300, but the battery is not discharging. This is taken from the analysis in section 4.5.3.

Figures 4.15 and 4.16 illustrate the cap contract required for the battery to be financially viable for FY15 and FY16 respectively. In the less volatile FY15, 30-minute settlement actually *increases* the cost of a cap contract, relative to the perfect ‘capacity only’ case, where the storage perfectly dispatches when the price is above \$300. This is due to the penalty payments that must be made as consequence of forecast errors.

The additional arbitrage revenue (from prices below \$300) in the 5 minute settlement case

Table 4.5: Battery costs (\$/kWh)

	Low	High
Initial capital cost (DC)	\$399	\$1,051
Initial capital cost (AC)	\$47	\$47
Initial other owners costs	\$57	\$165
Total initial installed cost	\$503	\$1,263
10 year replacement cost (DC)	\$209	\$304
10 year replacement cost (AC)	\$32	\$32
Total 10 year replacement costs	\$241	\$336
Operations and maintenance Costs	\$8	\$13

⁵See page 83 in chapter 3

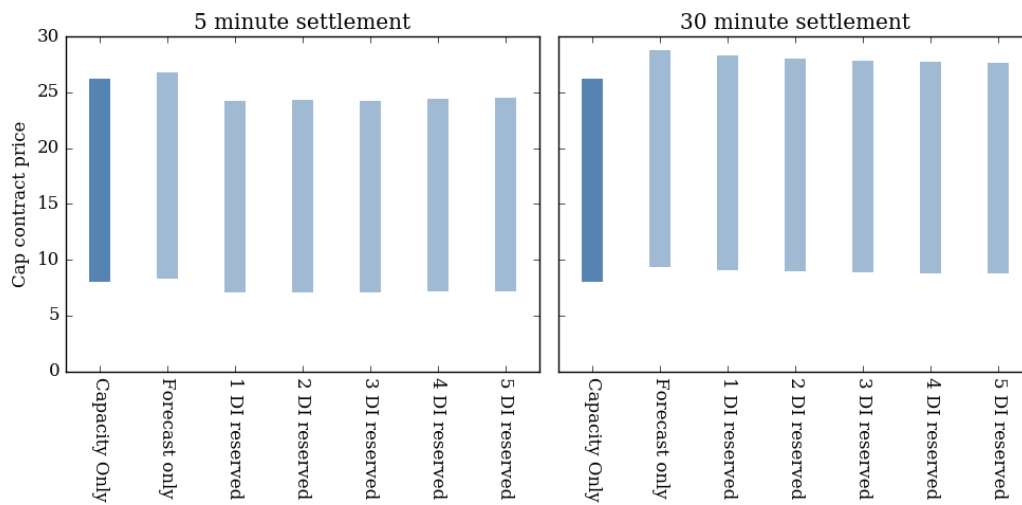


Figure 4.15: This figure illustrates the range of cap prices that a lithium battery would require to be financially viable under different settlement periods and different operating regimes for FY15. The dark bar represents the cap contract price for a perfectly operated battery that only operates when prices are above \$300.

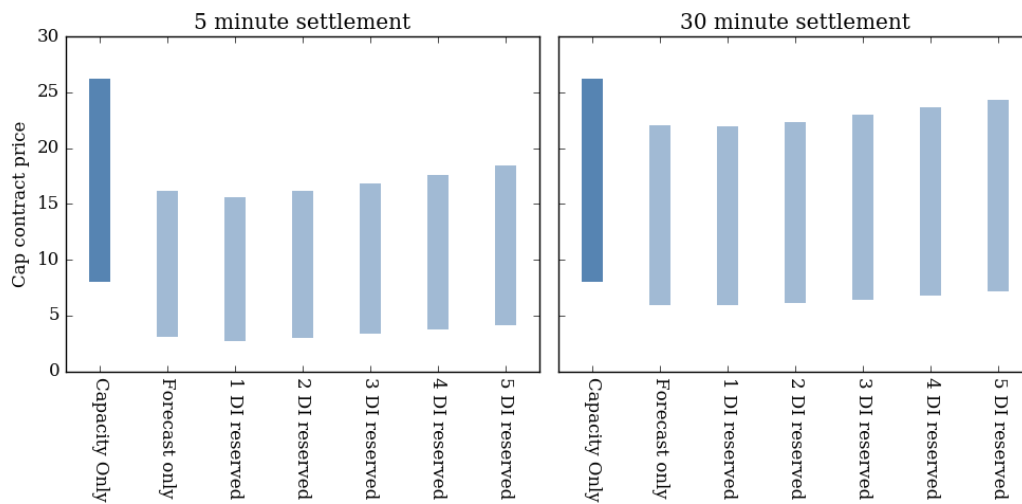


Figure 4.16: This figure shows the range of cap prices that a lithium battery would require to be financially viable under different settlement periods and different operating regimes for FY16. The dark bar represents the cap contract price for a perfectly operated battery that only operates when prices are above \$300.

means that a lower cost cap contract can be offered. This additional revenue gives storage technologies a competitive advantage relative to some peak generation technologies that would not necessarily operate at prices below \$300.

In the more volatile FY16, the advantage of 5-minute settlement is clearly visible. While the additional revenue from prices below \$300 lowers the cost of the cap contracts in both cases, the impact is considerably larger under 5-minute settlement. For the low cost estimate, 30 minute settlement increased cap contract prices by 30% relative to the 5 minute settlement case.

4.7 Conclusion

Thirty-minute settlement combined with 5 minute dispatch clearly creates perverse incentives and sub-optimal dispatching of generation resources. The current mismatch between settlement and dispatch:

- Diminishes the value of fast dispatch,
- Encourages sub-economic dispatch,
- Does not provide appropriate incentives for fast response generation, and
- Creates opportunities for creative compliance (rebidding).

The existing rules create perverse incentives for bidding behaviour and mute the incentive to efficiently respond and dispatch in a truly ‘fast’ market. The results of the analysis presented in this chapter suggest that there are clear benefits to both shortening the settlement period, and aligning it with dispatch. These benefits accrue through simultaneously improving the incentives for flexible generation, critical to facilitating integration of renewable energy, while also removing distortions and perverse incentives in the normal operation of the market.

Chapter 5

The future of frequency control and system security

Introduction

Frequency control and system security has long remained an obscure corner of the NEM, that historically received little public attention. That changed dramatically following the ‘system black’ event in South Australia in 2016. At the national level, the Council of Australian Governments Energy Council initiated the *‘Independent Review into the Future Security of the National Electricity Market’* (Finkel 2017), and the South Australia Government launched the *‘South Australian Power Plan’*. This involved several components, including the state-funding for a peaking generator, as well as the Hornsdale Power Reserve battery ¹.

This Hornsdale Power Reserve facility has largely provided value to the *‘Frequency Control and Ancillary Service’* (FCAS) markets and provides a unique opportunity for analysing the impact of new battery technologies in such services. This chapter focuses on the Hornsdale Power Reserve performance in FCAS terms. The chapter begins with an overview of the current frequency control regime in the NEM, and then looks at how the battery has operated in the market. Following on from, and expanding on the model developed in, chapter 3, I consider

¹ which locally has become known variously as ‘the largest battery in the world’ and ‘the Tesla mega-battery’

the value of the co-optimised operation of a battery storage device in the NEM. The chapter concludes with a discussion of the results and a summary of findings.

5.1 Frequency control in the NEM

In the NEM, frequency control is coordinated through the market, and is co-optimised with the energy market as part of the economic dispatch optimisation process. The so-called NEM Dispatch Engine (NEMDE) co-optimises energy with FCAS for each 5min dispatch interval. There are eight separate Frequency Control Ancillary Service (FCAS) markets that are simultaneously optimised with the energy markets to ensure secure operation of the power system at least cost.

The eight FCAS markets are broadly classified into two categories termed contingency services and regulation services, respectively. The contingency services are analogous to reserve markets in other jurisdictions, providing primary and secondary frequency control, the essential reserve for the case of a large contingency. The regulation services provide a fine-timescale balancing (regulation) of the frequency.

5.1.1 Contingency services

Contingency services essentially stabilise the system when a ‘*contingency event*’ occurs. A contingency event typically involves the failure or sudden and unexpected removal of a generating unit (e.g. the trip of a large load), a load (e.g. the trip of an aluminium pot-line) or a transmission failure (e.g. loss of a transmission line due to weather).

When such unexpected events occur, supply and demand are no longer balanced, and the frequency of the power system moves away from the normal operating range, on a very short timescale. The contingency services ensure that the system is brought back into balance and that the frequency is returned to within normal operating range within 5 minutes.

In the NEM, the frequency is maintained within a ‘*normal operating frequency band*’ between 49.85 and 50.15Hz, nominally 50Hz (AEMC Reliability Panel 2017). When the frequency moves outside of this range, *enabled* capacity responds by automatically increasing or decreasing output as is appropriate². *Enabled* capacity is capacity that is set aside or reserved, ready to

²This response is triggered at the power station by the change in frequency as measured on site. Historically

automatically respond to a frequency deviation³.

In the NEM there are three separate timescales over which these reserves or contingency services need to be delivered following a contingency: 6 seconds, 60 seconds, and 5 minutes. Figure 5.1 illustrates how these services restore the system after a drop in frequency (for example when a power station trips off). As the contingency service may have to increase or decrease the frequency, there is thus a total of six contingency market (three that raise frequency and three that reduce it, over the 6s, 60sec and 5 minute timescales respectively, see table 5.1).

5.1.2 Regulation services

Regulation services are continually used to correct for minor changes in the demand and supply balance, *within* the 5 minute dispatch interval (AEMO 2015a). The minor corrections required can be due to a range of factors, such as an error in demand forecast or a generator failing to meet its dispatch target.

Regulation services are governed by signals from AEMO, and therefore differ from contingency services signalled by an unexpected local change in frequency. The output of the enabled

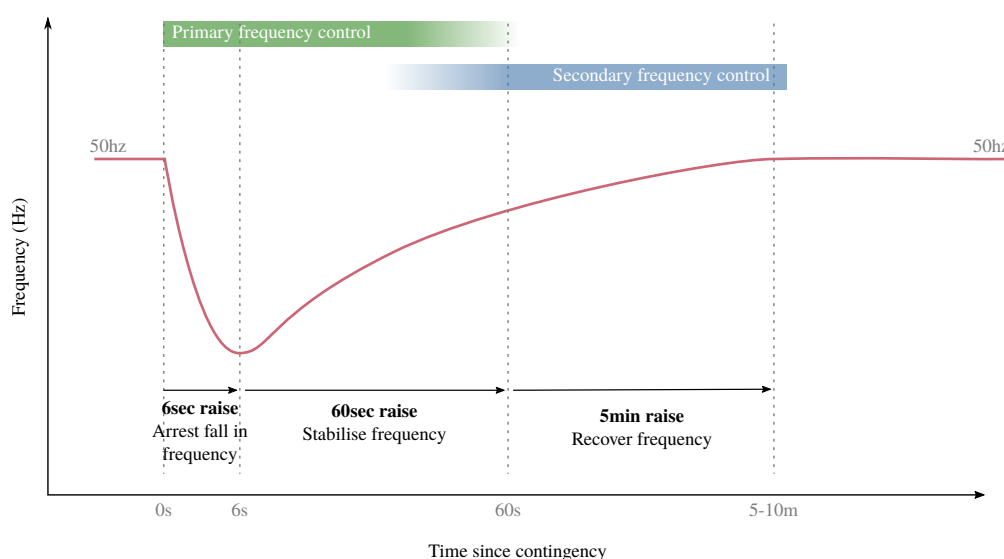


Figure 5.1: Illustration of how the three raise contingency services work in concert with each other to restore frequency following a contingency event. Note that the x-axis is not scaled and is thus approximate only.

this service has usually been provided by increasing or decreasing output from thermal generators.

³Sometimes referred to as 'spinning reserve'.

Service	Raise	Lower
6 second	Raise 6 sec	Lower 6 sec
60 second	Raise 60 sec	Lower 60 sec
5 minute	Raise 5 min	Lower 5 min
Regulation	Raise reg	Lower reg

Table 5.1: All eight FCAS markets in the NEM

generators is controlled via the Automatic Generation Control (AGC) system at 4 second intervals. The AGC system essentially allows AEMO to continually monitor the system frequency and signal generators to alter their output a manner such that the frequency (and thus supply and demand) is balanced. As with contingency services, there is both a raise and lower regulation service (table 5.1 lists all frequency control services).

5.1.3 FCAS cost and demand

The pricing of the FCAS market is linked to the pricing of the wholesale market, because for generators there is a trade off between selling capacity in the FCAS market⁴ or using that capacity to sell into the energy market. Consequently, the incentive to make capacity available to the FCAS market must be linked to the opportunity cost of using that capacity to sell into the energy market. As such FCAS prices might be expected to increase in line with wholesale market prices.

In this context, it is not surprising that both wholesale and FCAS market prices increased dramatically across the NEM in early 2017 and have remained high ever since. The wholesale market prices increased by a factor of around 1.7, compared with twelve months earlier, with the market values rising from about \$10 billion to \$17 billion. The increases can be attributed to a number of factors, including the closure of the 1600 MW capacity Hazelwood power station in Victoria, decreases in the level of competition in generation, as well as increases in gas prices that followed the opening of the east coast gas market to international trade via LNG exports. Many of the factors are common to the particular experience in South Australia as discussed in chapter 2. Detailed analysis of these drivers was the subject of a long running inquiry by the Commonwealth Government agency, the Australian Competition and Consumer Commission (ACCC 2018).

⁴FCAS services are priced in \$/MW per hour.

Up until 2014-15, the market value of all FCAS services was in the vicinity of \$20-40 million per annum or about 0.2-0.4% of the wholesale market⁵ (AEMO 2015a). Now the FCAS market is valued at approximately \$200 million per annum, representing a 5-10 fold increase in costs. Figure 5.2 shows the quarterly value of the FCAS, by service since the beginning of 2016.

It is clear that the cost of FCAS has risen substantially more than would be expected from the opportunity cost of the energy market alone. While a full examination of the drivers of FCAS demand and costs are beyond the scope of this work, the potential additional factors for the relatively larger rise in FCAS prices are briefly discussed below.

Firstly, it has been argued that increases in the proportion of variable renewable energy in the generation mix leads to an increase in demand for FCAS. However, for the NEM this seems unlikely to be a significant factor because the data indicates little change in total FCAS *demand* over this period⁶. For example, as shown in figure 5.3, there is no systemic increase in demand

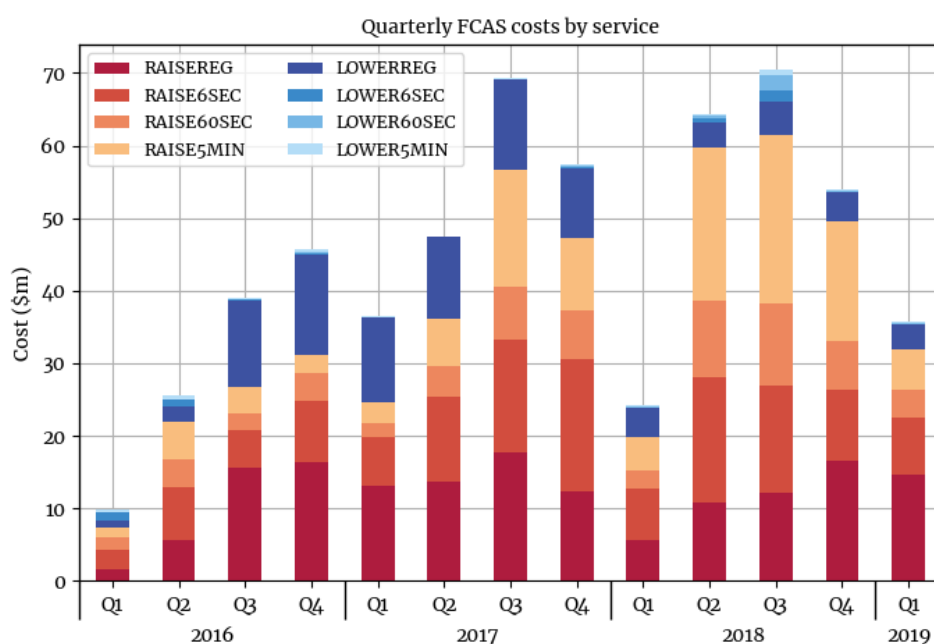


Figure 5.2: Quarterly cost of FCAS services in the NEM over time. Raise services are responsible for the majority of the cost (raise regulation and raise 6 second services contribute approximately 50% of the costs).

⁵The cost of these services are borne by market participants, through on a “causer pays” basis.

⁶In the conventional sense of FCAS, as described thus far in this chapter. Inertia and system strength concerns

for average daily regulation raise in lower enablements for South Australia with time, despite a substantial increase of renewable energy generation in the last decade. Similarly, contingency services are related to the largest contingencies, which are generally related to trips of large single units. Over time, with the addition of the smaller more distributed renewable resources, this may actually be expected to decline, as has been seen in Germany (Hirth and Ziegenhagen 2015).

An obvious additional possibility is that the dynamics of the FCAS markets suffers from lack of competition. FCAS markets tend to be more concentrated than the energy markets. This tendency has been somewhat exacerbated because, until recently, renewable energy and other emerging technologies (such as demand response) were not able to participate as FCAS providers. A limited pool of participants, which has been a particular problem in South Australia⁷, may have engendered a high degree of oligopolistic pricing.

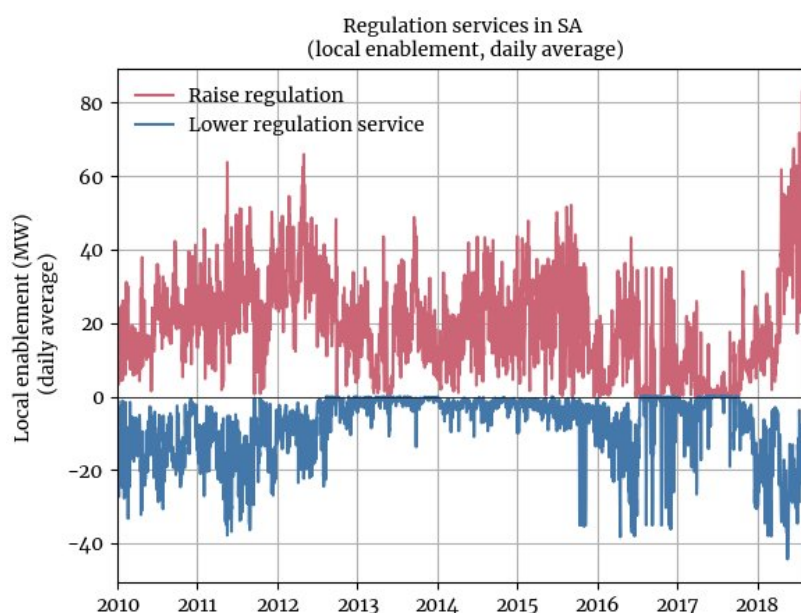


Figure 5.3: Daily average enablement for regulation services in South Australia over time. Despite the substantial increase in renewable energy over the last decade, there has no systemic increase in demand for regulation services.

are discussed separately in section 5.5

⁷For some time, following the closure of Northern, there were only two or three generators selling FCAS in South Australia

There are also no derivative or contract markets associated with the FCAS markets. There are 8 small markets, with no ability for either FCAS providers (or the liable entities paying for regulation services) to hedge their exposure and support investment in new assets. As such, investment to specifically support these markets is limited.

Finally, some have argued that recent changes to governor settings may be responsible⁸ (Summers 2017).

5.2 The Hornsdale Power Reserve

The Hornsdale Power Reserve “*mega battery*” facility was completed in late November 2017 and is the first utility-scale battery to connect to the NEM. It is physically co-located alongside the Hornsdale Wind Farm and was constructed in partnership between the South Australian Government and the French renewable energy company Neoen that owns and operates the wind farm.

The battery has a total generation capacity of 100 MW, and 129 MWh of energy storage. While not formally reported, long term data suggests the round trip efficiency is in the vicinity of 80%. Notionally, the configuration implies approximately 1.33 hours of storage, however the facility is best thought of as comprising two systems. One component has 70MW of output capacity that has been contracted to the SA government, and is reported to provide non-market system security services with about 10 minutes of storage. The second component comprising 30MW of output capacity, has a storage capacity of about 3-4 hours and participates in the competitive part of the market. It is this second component that is focus of this analysis of attention in this chapter.

Figure 5.4 illustrates the flexibility of the battery. Available market data shows it is capable of ramping from zero to the full 30MW (and vice versa) in as little as four seconds. In reality, it is reportedly much faster than this - ramping from 0 to full capacity at the 100 millisecond scale. While impressive, the energy dispatch and load illustrated in this figure makes little sense without considering how it also participates in the FCAS markets. Figure 5.5 illustrates the battery responding from rest to a contingency event, while figure 5.6 shows both the enablement

⁸Some generators may have essentially been providing FCAS for free, until a relatively recent change in the FCAS regime.

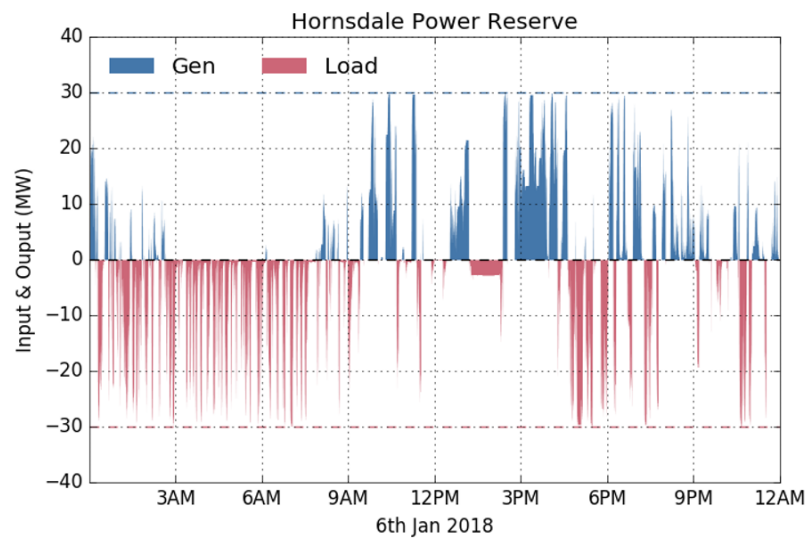


Figure 5.4: Hornsedale Power Reserve generation (discharging) and load (charging) for a day in January. The output increased from zero to 30MW (full output) in less than 4 seconds. Note that dispatch from HPR is changing faster than 5 minutes, the length of the normal dispatch interval.

and output from the battery as it provides regulation services. Figure 5.7 and figure 5.8 provide a comparison of the battery's performance in providing raise services and responding to the AGC set point with that of a large steam turbine. As can be seen, the battery displays a superior performance with respect to both speed and accuracy.

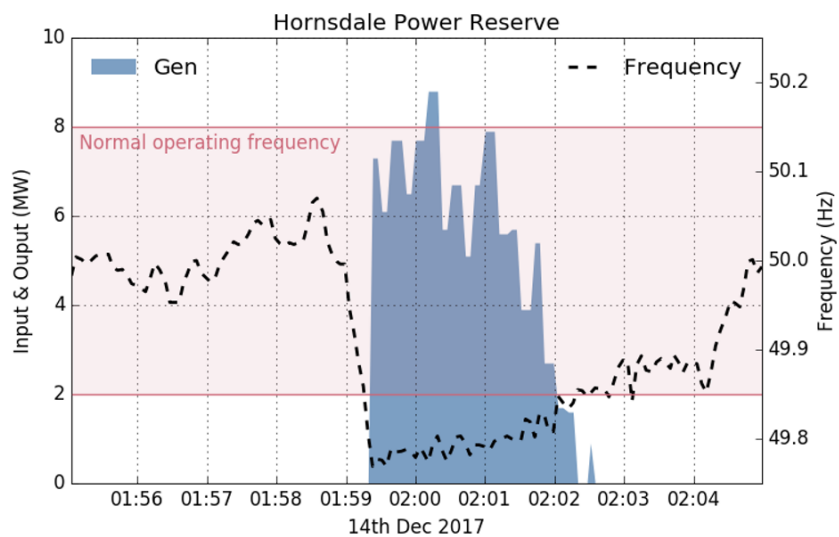


Figure 5.5: Hornsdale Power Reserve responding to a drop in system frequency, following the trip of a large generator interstate (Loy Yang A) on the 14th of December 2017.

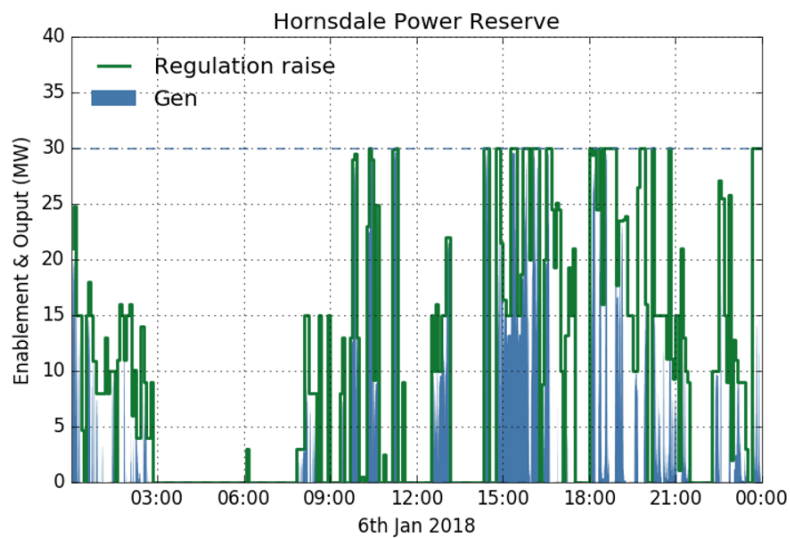


Figure 5.6: Hornsdale Power Reserve output and enablement in the raise regulation market. Note that the enablement is the amount of capacity that *can* be given directions to, in order to provide regulation services, not the amount that *is* given directions (the target). 5.7).

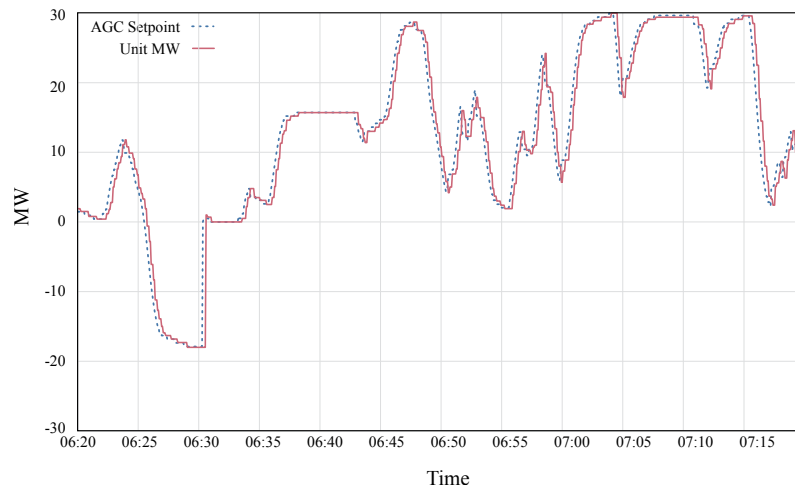


Figure 5.7: Accuracy and speed of regulation response from Hornsdale Power Reserve battery. Note how closely the battery follows the set point [data source: (AEMO 2018)].

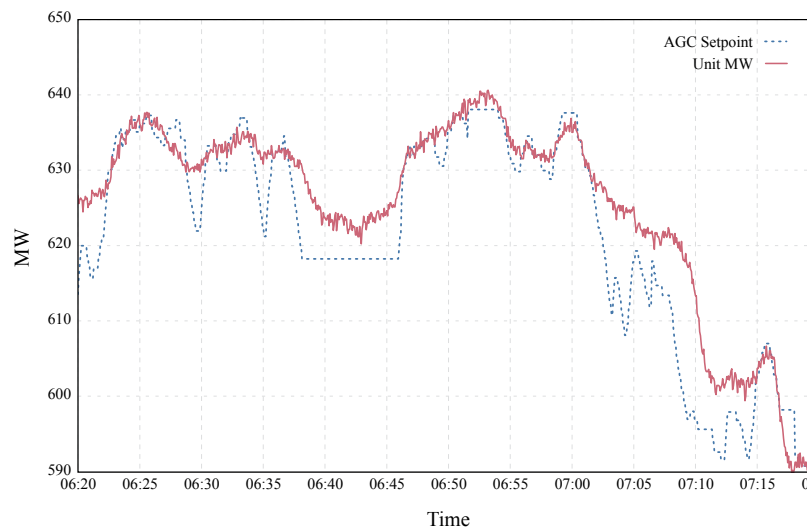


Figure 5.8: Accuracy and speed of regulation response from a large steam turbine. In this case the steam turbines response range (and amount of capacity available for providing regulation services) is similar to that in the figure of the Hornsdale Power Reserve above [data source: (AEMO 2018)]

5.3 Co-optimisation of FCAS and Energy

As discussed in chapter 3, energy storage studies have historically focused on the arbitrage value of storage in the energy market. Recently, more studies have been considering the co-optimisation of ancillary services and energy markets (see Anderson 2018 for a review of recent studies). The experience at Hornsdale also shows that battery storage has significant potential in provision of FCAS. This presents an opportunity to further analyse the interaction between emerging technologies and legacy market designs, particularly in the context of the increasing focus and cost of the FCAS markets.

In this section, I more formally investigate the co-optimised dispatch of a utility scale battery in the South Australian market region.

Model description

The model used here to co-optimize energy and FCAS services builds on the model developed in chapter 3. It adds a decision variable for the FCAS markets, and modifies the constraints such that the capacity enabled in the FCAS markets and utilised to generate or consume power from the energy market is less than the total capacity available at the storage system being modelled.

In modelling this problem, I make two simplifying assumptions. Firstly, that the storage device can be simultaneously enabled for 6-second, 6-second and 5-minute contingency services. This assumption is valid for battery technologies that can ramp from 0 to maximum power in less than a second, and sustain that output for well over 5 minutes⁹. However the assumption may not hold for other storage devices, for example pumped hydro that may have longer start up times, or may need to be spinning¹⁰ to provide FCAS services.

In addition, I assume that selling capacity in the FCAS markets does not affect the energy balance of the plant. This assumption is reasonable for contingency services, where the frequency of contingency events is relatively low¹¹ and the energy delivered during an event is also small (≤ 5 min of the capacity enabled). For regulation services, the assumption is roughly equivalent

⁹Traditional FCAS provides maybe able to increase output within 6sec, but cannot sustain that increase for enough time for recovery of FCAS, hence multiple FCAS markets.

¹⁰That is, already generating.

¹¹In practice, contingency services might respond to an event 1-2 times a month.

to the governor directions for regulation services being equally distributed between raise and lower on balance. This assumption may be less likely to be valid, however in the case that it is unbalanced, the amount of energy required to re-balance the storage device is assumed to be small.

Another noteworthy characteristic of batteries is that when charging, the effective capacity that can be sold into the raise market increases in proportion to the charging rate. Correspondingly, when discharging, the amount of capacity available in the lower market is increased. This is due to the fact that the battery can oscillate from charging at (say) 30 MW to discharging 30 MW in a matter of seconds, giving a net 60MW turn around. This capability is also reflected in the constraint equations below.

The optimisation problem outlined below reflects the changes to the initial problem (The full problem description can be found in appendix E.1. Equation 5.1 adds the FCAS revenue stream to the objective function, and introduces the four new decision variables, reflecting the amount of capacity in the contingency markets and the regulation market, for both raise and lower services. The new constraints in equation 5.2 ensure than the amount of capacity sold in each of the markets is below the maximum (and the energy balance constraint remains unchanged).

Maximise:

$$\sum_{i=1}^n P_{e_i} \cdot (Q_{c_i} - Q_{d_i}) + P_{rr_i} \cdot Q_{rr_i} + P_{lr_i} \cdot Q_{lr_i} + P_{rc_i} \cdot Q_{rc_i} + P_{lc_i} \cdot Q_{lc_i} \quad (5.1)$$

Subject to:

$$0 \leq (Q_{d_i} + Q_{rr_i} + Q_{rc_i}) - Q_{c_i} \leq Q_{d_{max}} \quad (5.2)$$

$$0 \leq (Q_{c_i} + Q_{lr_i} + Q_{lc_i}) - Q_{d_i} \leq Q_{c_{max}} \quad (5.3)$$

Where:

Q_{rr_i} = capacity enabled for raise regulation for interval i

Q_{rc_i} = capacity enabled for lower regulation for interval i

Q_{lr_i} = capacity enabled for raise contingency for interval i

Q_{lc_i} = capacity enabled for lower contingency for interval i

P_{rr_i} = raise regulation price at interval i

P_{lr_i} = lower regulation price at interval i

P_{rc_i} = raise contingency price at interval i

P_{lc_i} = lower contingency price at interval i

For this analysis, three different storage amounts (in hours) are considered, 30 minutes, 1 hour and 2 hours, respectively. As with the analysis in chapter 2, this analysis is essentially dimensionless. However, a 100 MW unit is used for illustrative purposes in the presentation of the results.

5.4 Results

The two panels in figure 5.9 and 5.10 illustrate the co-optimised dispatch of a representative 100MW utility scale battery across the eight FCAS markets and the energy markets. As can be seen, the battery spends much time enabled in the FCAS markets, but continues to take arbitrage opportunities in the energy market. This reflects the value of the regulation markets relative to the arbitrage opportunity in the energy market for the relevant periods (see figure 5.2).

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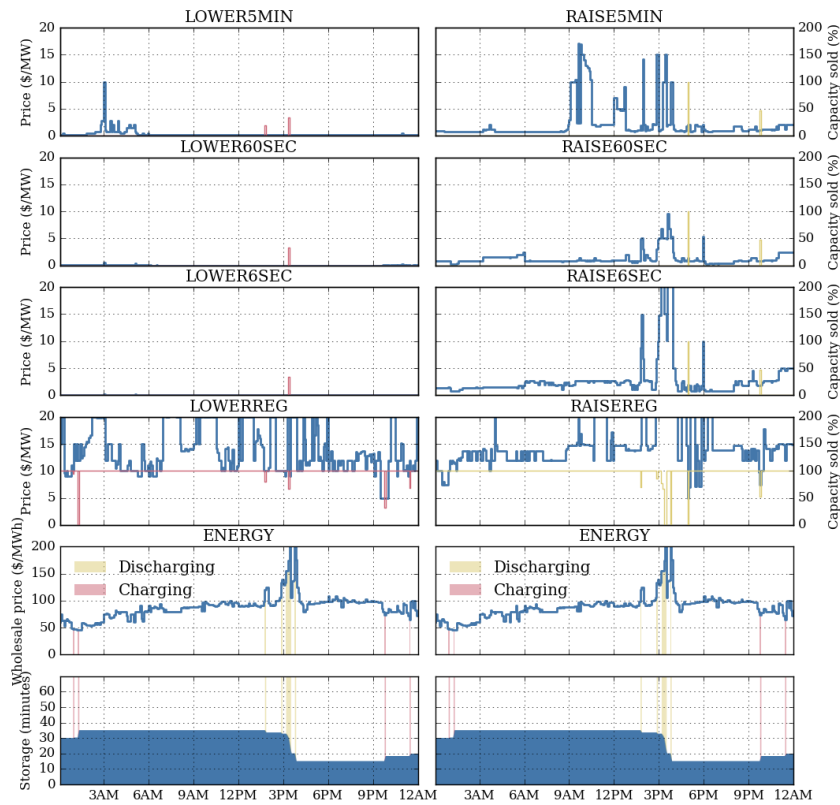


Figure 5.9: Co-optimised output from a utility battery, on a representative day of low volatility in the energy market (2 Feb 2017). The top eight panels show the price (blue, left hand axis) and enablement (red or yellow, right hand axis)) in each of the markets. The bottom panels show the energy price and storage levels, and indicate whether the device is charging or discharging (red or yellow). The panels showing energy and storage levels are repeated, so as to share visualise the dispatch in each market on the same x axis. Note that the battery (assumed to be 100MW in this case) spends most of the day enabled in the regulation markets.

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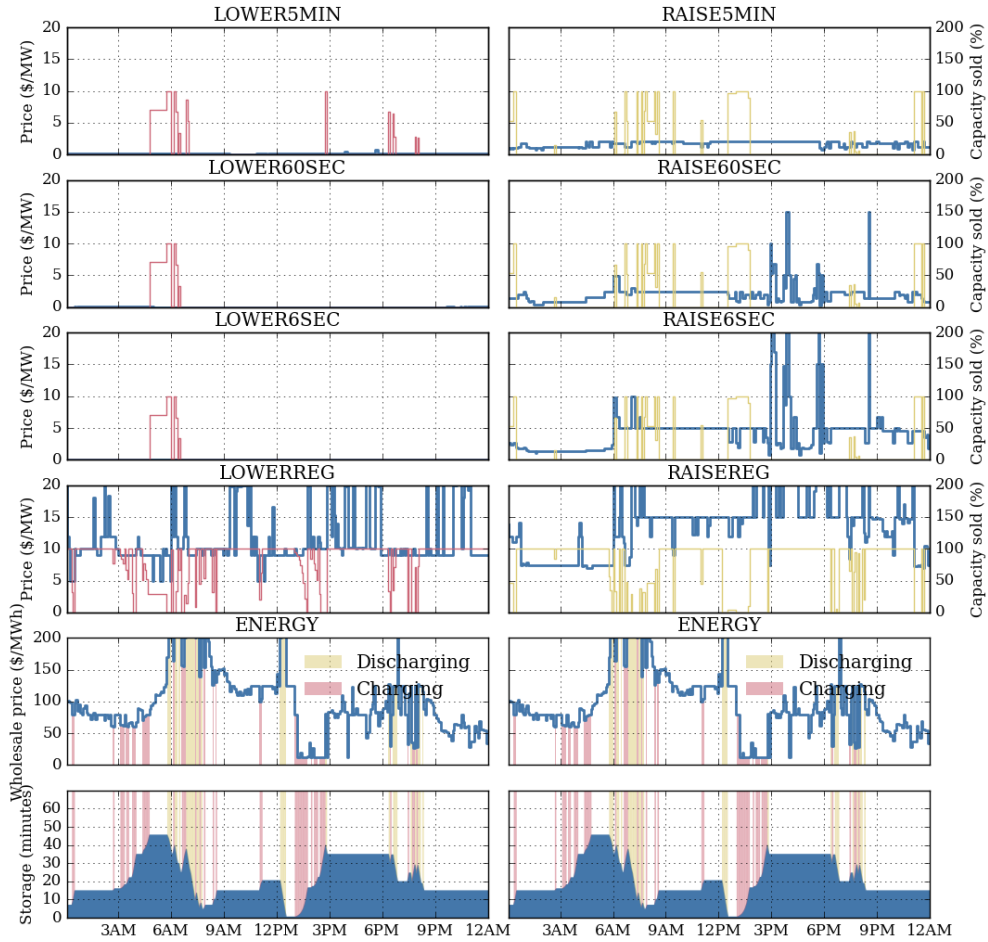


Figure 5.10: Co-optimised output from a utility battery, on a representative day of higher volatility in the energy market (6 Feb 2017). The top eight panels show the price (blue, left hand axis) and enablement (red or yellow, right hand axis) in each of the markets. The bottom panels show the energy price and storage levels, and indicate whether the device is charging or discharging (red or yellow). The panels showing energy and storage levels are repeated, so as to share visualise the dispatch in each market on the same x axis. On this day the battery switches between the different markets multiple times providing maximum value to (and extract maximum revenue from each of the markets).

Figure 5.11 shows the value of storage capacity across the energy and FCAS markets expressed in \$/kW-year. This value compares with a range of \$50-\$300/kW-year for energy arbitrage alone, as found in chapter 3 (see 3.5 in section 3.3, *Relationship between storage configuration and value*).

There are several noteworthy results that can be drawn from this figure. First and most obviously, there is a substantial increase across the years. This corresponds with the almost ten times increase in the value of FCAS across the period. Secondly, the value of the capacity in the FCAS market is substantially greater than that in energy market through arbitrage alone. Finally, the marginal value of additional hours of storage is limited. The analysis indicates that the majority of value can be found in the *capacity* of the battery. As the hours of storage affects the amount of *energy* stored in the battery, it predominantly affects the arbitrage value, in a manner that is consistent with the results from chapter 3 (see figure 3.7).

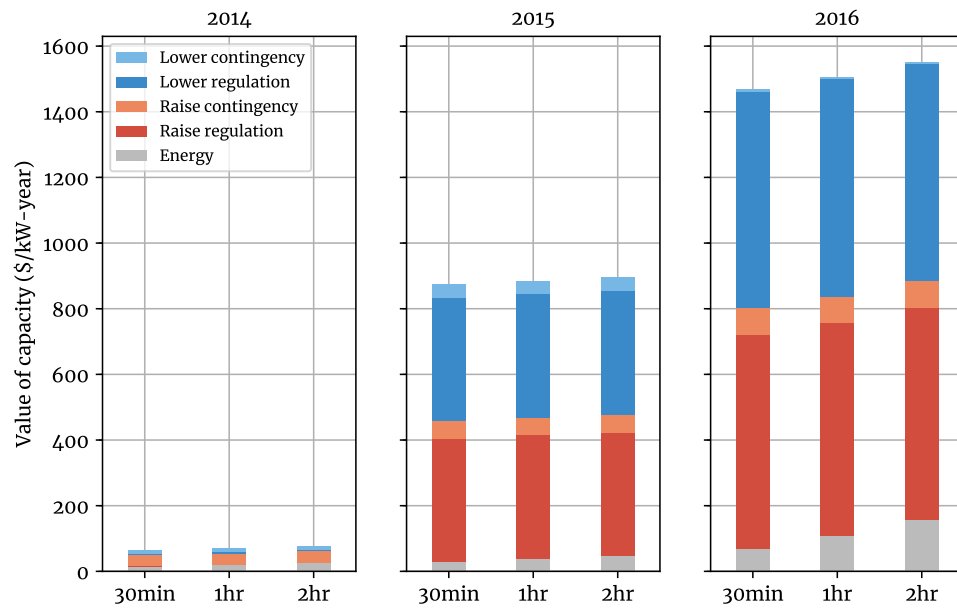


Figure 5.11: This figure shows the co-optimised value of storage for the South Australia market region across all markets (FCAS & energy), and with different amounts of storage. Increasing the storage duration doesn't have a dramatic effect on the value.

Type	Service	2014	2015	2016
Energy	Charging	0.5	1.1	2.6
	Discharging	0.5	1.0	2.4
Raise	Contingency	94.5	88.9	68.8
	Regulation	5.0	10.1	28.6
Lower	Contingency	23.7	25.2	20.7
	Regulation	75.7	73.7	76.1

Table 5.2: Percentage of time storage capacity is enabled or active across each of the markets. As can be seen, for the majority of the time, the capacity is utilised in both the raise and lower FCAS markets.

Table 5.2 shows the proportion of time that the battery spent more than 95% of the time enabled in the FCAS markets across the three years. While this may seem counter intuitive, because the prices in FCAS markets are not generally high (see table 5.3), it reflects the fact that the battery is able to continuously participate in FCAS market without actually drawing on much energy. This is particularly the case for the contingency services, where the battery can be simultaneously enabled across all three raise and lower services with negligible usage¹².

While the battery spends much time enabled in the raise contingency markets, more value is derived from the raise regulation markets. This is consistent with the peaky nature of raise regulation prices (as evidenced, for example, by comparison of the mean and median prices in

Type	Service	<i>Median price</i>			<i>Mean price</i>		
		2014	2015	2016	2014	2015	2016
Raise	Regulation	\$1.54	\$1.88	\$11.99	\$1.91	\$45.48	\$83.45
	6 sec contingency	\$0.94	\$0.80	\$3.27	\$1.42	\$2.28	\$5.22
	60 sec contingency	\$0.80	\$0.80	\$2.00	\$0.88	\$1.95	\$3.17
	5min raise	\$1.30	\$1.75	\$2.08	\$1.67	\$2.61	\$3.02
Lower	Regulation	\$0.52	\$0.70	\$5.00	\$1.18	\$44.77	\$76.68
	6 sec contingency	\$0.03	\$0.02	\$0.02	\$0.43	\$1.98	\$0.42
	60 sec contingency	\$0.15	\$0.07	\$0.06	\$0.38	\$1.85	\$0.22
	5min raise	\$0.47	\$0.44	\$0.19	\$1.00	\$2.20	\$0.68

Table 5.3: FCAS market price statistics

¹²The battery would only be charging or discharging in the case of a contingency event, which only happen infrequently and for short durations.

table 5.3). The regulation markets are consequently more prone to hitting the market price cap (currently \$14,500), with the consequence that a relatively small number of events can strongly skew the total revenue in analogous fashion to the energy markets.

As mentioned earlier, market concentration is a potentially acute issue in the FCAS markets. As such, the market outcomes may be indicative of oligopolistic pricing rather than fundamentals of the demand supply balance with efficient scarcity pricing. To investigate the impact of the scarcity pricing and the potential impacts of uncompetitive pricing outcomes, the analysis was also completed by assuming a maximum price of \$300 across all the markets. Unlike the energy market, in the absence of cap contracts or any contract market for FCAS, there is no strong precedent for choosing this price. However, due to the linkage between the energy market and FCAS market, I consider this to also be a reasonable signal of scarcity. Periods with prices above \$300 are likely to be periods where competition issues would manifest most obviously.

Figure 5.12 below shows that the \$/kW-year value for price events greater than \$300 represents approximately 50% of the total market value (as shown in 5.11), indicating the impact of a

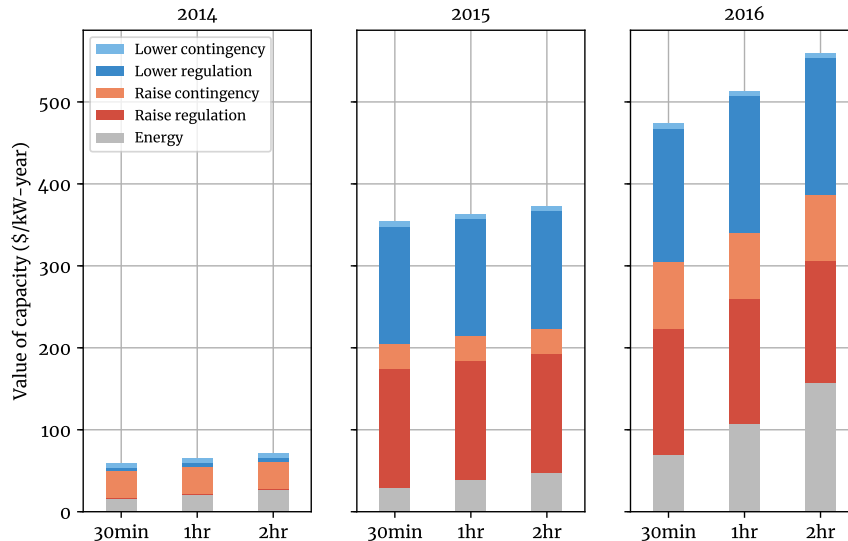


Figure 5.12: This figure also shows the co-optimised value of storage for South Australia market region across all markets (FCAS & energy), and with different amounts of storage. However, in this case, the prices across the FCAS markets are capped at \$300. As above, increasing the storage duration doesn't have a dramatic effect on the value.

relatively small number of high FCAS price events. In addition to the impact on absolute value, the previous observations also broadly hold true. In particular, the marginal value of an increase in the hours of storage is limited to the energy (arbitrage) operation of the battery. The FCAS services are a much greater value stream than those from the energy market.

These results are consistent with the observed revenues from the Hornsdale Power Reserve. Figure 5.13 shows a breakdown of the different revenue streams across the year. While the ratio of the contingency to regulation revenue is different to the modelled values, the relative magnitudes of the value of the FCAS and energy markets is very similar. Scaling the model results to the size of the Hornsdale Power reserve also yield broadly similar results. For example, the FCAS modelling results from 2016 would translate to an FCAS revenue of approximately \$12 million. Differences between the modelled results and observed values at Hornsdale most likely reflect the changed market conditions between 2016 and 2018.

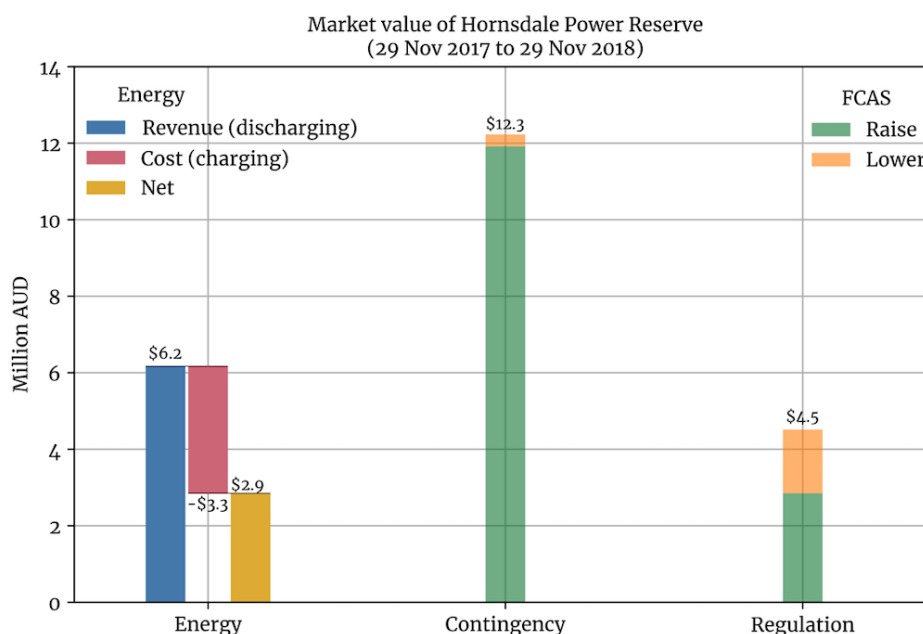


Figure 5.13: This figure illustrates the revenue streams from the FCAS markets and energy markets in the first 12 months of operation for the Hornsdale Power reserve.

5.5 Discussion - the future of frequency control

The analysis of the Hornsdale Power Reserve facility presented here provides confidence in the promise of battery technologies in frequency control service markets. Both modelling results and observations from the operation of Hornsdale show both the value of the storage in the FCAS markets, while superior performance has also been demonstrated.

There are however some caveats to this analysis. Most significantly, this analysis relies on historical data, and makes no assumptions with respect to how other participants or competitors might respond to the new entry of a battery storage facility. The results are therefore strictly only relevant under the ‘small-device’ assumption, whereby the battery is considered too small to impact prices. To date, the FCAS markets have remained stubbornly high, even with the addition of the Hornsdale Power Reserve, as well as several demand side response aggregators. As more batteries are connected to the system¹³ this assumption will eventually fail. It is of significant note that despite the limited number of participating batteries and demand response aggregators, they already provide more than 25% of the requirements in some of the FCAS markets across the entire NEM (AEMO 2019). Internationally the addition of battery resources into ancillary service markets has shown signs of beginning to drive down the associated clearing prices (Chen 2017).

The impact of Hornsdale raises important questions about the long term future or desirability of the current FCAS market design. For example, there is unlikely to be any need for 3 separate contingency markets in battery storage dominated FCAS markets, as a battery can efficiently provide over all three timescales. Indeed, it does not necessarily make sense to have any of the eight markets: a handful of Hornsdale-like batteries strategically located around the NEM could theoretically provide the entire FCAS market function, at lower cost and with greater precision than the current arrangement.

The entire NEM FCAS market (both regulation and contingency), including both raise and lower, could be provided with approximately 1500MW of battery capacity, with a relatively small amount of hours of storage capacity. For example, a 30 minute battery held at a 50% state of charge could dispatch for 15 minutes in either direction (raise or lower) which is longer than is

¹³There are currently four utility scale projects, each with approximately 30MW of capacity participating in the competitive part of the NEM.

necessary for the current FCAS markets. Based on a 2018 update to ‘the future cost of electrical energy storage based on experience rates’ (Schmidt et al. 2017), this utility storage would cost in the vicinity of \$580 million. The reported Hornsdale costs (\$90million for 129MWh of storage) would translate as a total cost to provide all FCAS of \$520 million (assuming 1500MW and 30 minutes of storage).

While there is a degree of uncertainty in these approximate costings, as the power-to-energy ratio may need to differ to the power-to-energy ratio assumed in this example, battery costs would have to be significantly higher (or market based FCAS costs become significantly lower) for this option not be considered further. Even if the amount of storage doubled (\$1.2 billion for a 1 hour battery), or the initial cost estimate was doubled, this still represents a potentially compelling option.

A regulated build of batteries providing FCAS might not only prove to be cheaper, it could remove the need for multiple FCAS markets while also providing the market operator with even greater control of managing the grid¹⁴. To the extent that a market based mechanism remains suitable, this still raises questions about the suitability of an eight market system.

5.5.1 Alternative options: Fast frequency response?

The large synchronous power stations that traditionally dominate power systems provide other services to the grid. Inertia is one of these services that is important in the context of frequency control. To date, inertia has been inherent with the synchronous generators that historically provide power to the grid, and as such hasn’t traditionally been valued by a market mechanism. In fact, inertia is often is provided at no cost. As large synchronous power plants leave the system, there will likely be a need for further consideration of the loss of inertia.

The inertia of the system effects the rate of change of frequency (RoCoF) to a disturbance. The rotational inertia from synchronous units provides an inherent and instantaneous response to frequency deviations, with slow RoCoF. The difference between a high inertia system and low inertia system is illustrated below in figure 5.14.

The amount of inertia in a system affects the *frequency nadir*, the point that the frequency

¹⁴For this claim, I assume the regulated batteries are operated by AEMO directly, rather than through the market

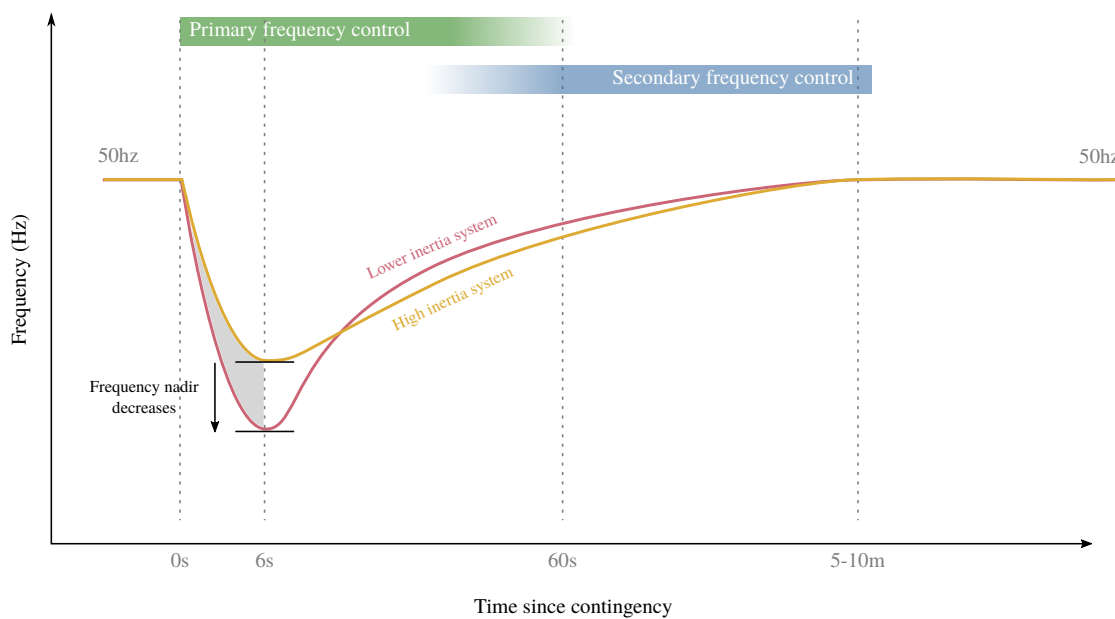


Figure 5.14: Illustration of how the level of inertia impacts the recovery of system frequency following a contingency event. Low inertia systems will reach a lower frequency (frequency nadir) following the loss of a load, increasing the risk of a cascading failure. The grey area highlights the impact of inertia on the system

drops to following a contingency event. The frequency in systems with lower inertia is expected to fall faster for a given event, and thus further before the primary frequency response arrests the decline¹⁵. This increases the likelihood of cascading failure, as protection systems at other generators trip, and disconnect more generation, which in turn exacerbates the event.

One additional service to address this issue has been termed “fast frequency response” (FFR). This is conceptually similar to the contingency services described above, but might occur at the timescale of tens to hundreds of milliseconds, rather than 6 seconds as is case for the fastest frequency response market currently.

FFR does *not* increase inertia (or reduce the RoCoF), but *does* reduce the magnitude of the frequency nadir. By shortening the time period between the contingency event and the injection of sufficient arresting energy, a substantial drop (or increase) in frequency can be avoided (see figure 5.15). So, while not a direct replacement for inertia, FFR can potentially reduce the need for physical inertia.

¹⁵The *arresting energy* - the overall amount of energy required to arrest to fall in frequency - is not increased, but the frequency to which the system falls to is increased.

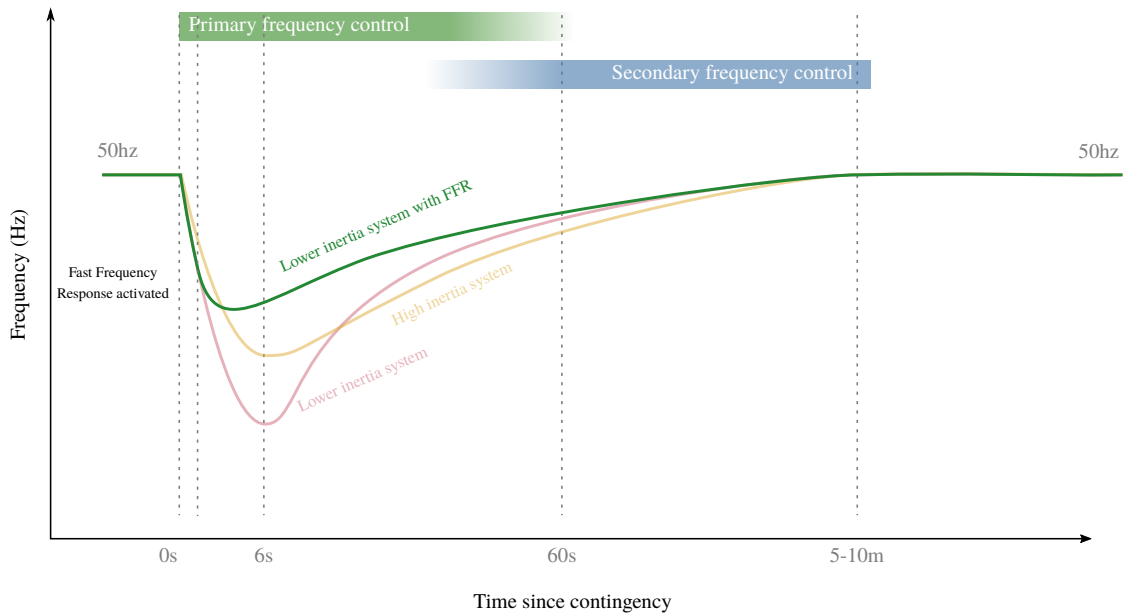


Figure 5.15: Illustration of how fast frequency response might impact the recovery of system frequency following a contingency event. Fast response may prevent the frequency nadir from falling too low.

The AEMC recently concluded a review of the frequency control framework in the NEM (AEMC 2018). The report concluded that the value of FFR to the power system is likely to increase over time, and the current framework does not adequately reward the FFR capabilities by technologies like batteries¹⁶. As a consequence, the AEMC is considering the introduction of a “*deviation pricing mechanism*”, whereby market participants are paid:

“...if their actions assist in moving the system frequency back towards 50 Hz. The cost of these payments is recovered from market participants that contribute to frequency deviations away from 50 Hz.”

How this would work in practice remains to be seen. As discussed earlier, the introduction of yet another market may not be the most efficient mechanism to deliver improved frequency control with emerging technologies.

¹⁶In the meantime, obligations on transmission companies are expected to ensure a minimum amount of inertia or similar services (such as fast frequency response)

5.5.2 Conclusion

The size of the Hornsdale Power Reserve battery is relatively small in the context of the National Energy Market. However, the analysis of its performance to date, as presented in this chapter, highlights the important role of batteries extends beyond the energy market. Indeed, the performance and capabilities extend beyond any other technology we have seen in the electricity system to date. With more batteries expected to come on line, questions remain about how these capabilities are best valued and remunerated in the electricity market.

Chapter 6

Discussion and conclusions

Power systems will inevitably experience profound change as the penetration of renewable energy generation increases. The remarkable cost reductions seen across the renewable energy sector, alongside efforts to decarbonise the economy, guarantee that renewable energy supply will continue to expand, and continue to disrupt electricity systems for years to come. A necessary corollary of concerted international action to honour the Paris Agreement objectives is the retirement of large amounts of emissions intensive generation.

In combination, these developments will provide serious challenges for the efficient operation of electricity markets. In liberalised energy-only markets, the addition of renewable energy will likely increase the capacity overhang, putting downward pressure on electricity prices. The corresponding withdrawal of existing emission intensive capacity, will necessarily reduce the capacity overhang and increase prices. Disruption will be most extreme when large thermal coal generators retire in an uncoordinated or unanticipated manner. South Australia provides an illuminating example of this process, with the progressive addition of a significant quantity of renewable energy eventually forcing the uncoordinated and sudden withdrawal of a large thermal generator (Northern power station).

As such dynamics play out, the market structure and generation scheduling rules are crucial in determining how the generation fleet is utilised. Electricity market design has a significant impact on the power system scheduling, operation and investment. This thesis has focused on

the way market design has impacted the dynamics in a system under transition, drawing largely on the experiences of the South Australian region of the National Electricity Market.

The analysis in chapter 3 explored how market structure provides incentives for flexible storage technologies. The analysis highlighted the annual variation in potential arbitrage revenue for a merchant generator, with the annual revenue highly skewed to a few days per year. The underlying volatility of the electricity prices is expected to increase as renewable energy penetrations increase, creating challenges and opportunities for financing new entrants and merchant storage facilities. Price spikes and volatility that critical for the financial *viability* of such new entrants, particularly those that provide capacity. This correspondingly increases their reliance on and exposure to price and volume *risk*. On the one hand, this may lead to sub-optimal investments, and create situations where market power issues are exacerbated. Battery operators themselves may find themselves in situations where they are able to take advantage of limited competition. On the other hand, increased competition in periods of scarcity should theoretically mitigate market concentrations and concerns with competition.

Related, the findings also raise questions about appropriate ownership arrangements for storage technologies. As discussed in chapter 3, vertical integration and different ownership structures will result in different optimal operating strategies, and may further entrench existing market competition issues

The analysis presented in chapter 3 suggests that having many hours of bulk energy storage is currently not viable. Specifically, there is little marginal value in extending storage capacity beyond about six hours. Whilst this is likely to remain true in the short- to medium-term, the longer-term implications are not clear. While the requirement for longer-duration storage may be expected to increase in the long-term, the investment signal provided by arbitrage in energy only markets is likely to remain insufficient. For example, longer duration storage will need more extreme scarcity pricing, it will pose a high risk investment proposition.

In addition to the change in physical characteristics of the electricity system, there are issues to do with market power concentration in systems under transition. There have been long running concerns about the level of market concentration in South Australia, and the NEM more broadly. The withdrawal of Northern power station (and before that Playford station), combined with limited interconnection to regional markets has, exacerbated market concentration to the

point where economic withholding of supply is both possible and profitable for some generators. There is similar potential and expectation for market power to be concentrated as a consequence of withdrawal of large amounts of capacity in other jurisdictions as well. The emergence of conditions that allow for the exercise of market power point to the need to carefully consider market design and concentration issues, on top of the need for more coordinated system planning of transitional arrangements.

Chapter 4 investigated a particular quirk of the NEM market design, related to the mismatch between dispatch and settlement timescales, which has the potential to be exploited by participants with high levels of market power. Chapter 4 summarises evidence that strongly suggests that some recent wholesale price spikes in the NEM may have stemmed from deliberate “exploitation”, rather than from underlying economic fundamentals. The chapter shows that the particular market rules related to dispatch and settlement intervals created perverse bidding incentives, and muted the incentive to efficiently respond and dispatch in a truly fast market. The results of the analysis presented suggest that there are clear benefits to both shortening the settlement period, and aligning it with dispatch. These benefits accrue through simultaneously improving the incentives for flexible generation, critical to facilitating integration of renewable energy, and removing distortions and perverse incentives. As had been found in other studies, improving market design characteristics can simultaneously facilitate the integration of variable generation while also improving the efficiency and operation of the existing market.

Ensuring resource adequacy is, of course, only part of the challenge in maintaining a functional power system. System security will also need to be reconsidered in light of the emergence of new technologies. Chapter 5 examined how battery technology can assist in the provision of primary and secondary frequency control. The chapter highlights that while improved system security is a key value that fast response batteries can provide the NEM, it is not currently appropriately rewarded. Incentives for fast frequency response may need to be re-thought.

The introduction of market liberalisation has generally required adjustments over time. This has included both fine-tuning rules as well as more significant overhauls, such as re-alignment of settlement and dispatch. It has been an ongoing process, in both Australia and abroad. Significant changes are expected to accommodate the changing market dynamics as the supply mix changes from a dominance of large-capacity thermal coal to a high proportion of variable

renewable generation. The analysis within this thesis, summarising the experience of Australia to date, indicates that there is significant potential for incremental changes in market design to efficiently accommodate the move to a high proportion of renewable energy and new technologies. However, whether or not such incremental changes *will* be sufficient is still up for debate. There are clearly still challenges for ensuring system adequacy in more volatile systems, and more substantial reforms and re-thinking of the approach to securing services may be required.

6.1 Competitive electricity markets: Questions remain about design, performance and future

The South Australian experience illustrates the potential for the energy transition to unfold along a dramatically different trajectory. The South Australian Government, through their ‘South Australian Power Plan’ represented a significant re-emergence of state ownership and state involvement in the generation sector, overturning 20 years of the conventional wisdom of liberalisation and economic reform of the power system.

The South Australian Power Plan included 276MW of peaking generation, the 100MW Hornsdale Power Reserve, as well as new laws giving more power to the state’s energy minister. In many ways, this represents a rejection of the market based approach that has dominated thinking in the electricity sector since the beginning of the NEM. Arguably, it represents a failure of the market to deliver capacity adequacy under the current framework.

Government intervention has not been restricted to South Australia. The recently re-elected Federal Government has committed \$1.4 billion to the so-called ‘Snowy 2.0’ project - a 2000MW pumped hydro project located in the heart of the NEM. In addition, the new *“Underwriting New Generation Investment”* program represents a direct example of the Government ‘picking winners’, rather than leaving capacity decisions to the market.

Other proposals that have received public attention, including amongst politicians, include the introduction of a formal capacity market, and the informal requirement to have certain portfolio of generation assets¹. The main argument for the implementation of capacity markets is that energy-only markets have not incentivised sufficient investment in generation to ensure resource

¹As seems to be the case with the recently developed *“Retailer Reliability Obligation”*

adequacy. This represents a significant departure from the current market-based approach to delivering reliability outcomes.

These developments may prove to be something of an anomaly in the history of the NEM, stemming at least in part from highly partisan climate policy. However, as discussed in this thesis, their manifestation is also evidence of the failure of the current market rules to ensure system adequacy in what is an increasingly volatile system. A worrying trend is the growing precedent for somewhat ad-hoc political intervention in the market.

A move away from market-based approaches is not without problems. The tacit centralisation essentially transfers investment risk from the private sector (e.g. generators) to regulators or central planners, and ultimately to the customers. For example, the inefficient allocation of risk raises the likelihood of ‘gold plating’ of generation infrastructure, for example.

This all raises questions about the performance of the NEM more broadly over its 20 years of existence. It is worth remembering that the NEM was liberalised and, until very recently, has largely functioned in a period dominated by oversupply, with a substantial capacity overhang. This has partly been driven by external policies related to renewable energy addition, in combination with declining or weak demand. As noted in chapter 2, it has been suggested that average wholesale prices in the NEM have been insufficient for many plants to recover long-run marginal costs. Arguably, many of the recent experiences with much increased volatility and the consequent higher clearing prices are the first real test of the NEM in providing adequate capacity.

These observations all provide rich avenues for potential further analysis. Needless to say, questions still remain about the design, performance and the future of the energy-only market design in the transition to a low carbon system.

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Appendix A

Development of the National Electricity Market

A brief overview of the development and reforms in the Australian Electricity Market is presented below. This aims to provide context for the current market arrangements and regulatory frameworks. Over a period of 30 years, the industry has moved from being dominated by protected, vertically integrated state owned monopolies, to a competitive market, with a disaggregated, corporatized and to a degree privatized industry structure.

A.1 Pre 1990: State Owned Electricity Monopolies

Electricity supply was historically a state responsibility. The electricity supply chain (from generation through to retail) was owned and operated by vertically integrated state based utilities. There was no wholesale market, and each jurisdiction supplied its own demand. With the exception of the Snowy Hydro Scheme (which has supplied Victoria and NSW with electricity since 1959), transmission lines did not cross state jurisdictional boundaries, and there was limit inter-state trade. The overall structure of the electricity sector was straight forward, with each state having its own power authority monopoly, (including the State Electricity Commission of Victoria SECV, Electricity Commission of NSW, ECNSW), alongside the Commonwealth's Snowy

Mountains Authority. There was no choice of supplier and governments protected the utilities from competition: all public electricity utilities were exempt from the Trade Practices Act. The various commissions were established by Acts of (State) Government, for example State Electricity Act 1958 (VIC), and the Electricity Commission Act 1950 (NSW) and the Snowy Authority under the Snowy Mountains Hydro-electric Power Act 1949 (C'th).

A.2 1985-1990: Industry Commission and other Inquiries

During 1985, the “*Commission of Inquiry into Electricity generation planning in NSW*” was established to examine and report on the current procedures and planning guidelines for allocation of resources and the recommended generation plan for NSW. The inquiry found that proposed new baseload investment by the ECNSW could be deferred by alternative options. The inquiry proposed excess capacity would have cost NSW several billion dollars, leading to the inquiry to conclude that the current institutions would ‘inefficiently allocate societal wealth’. A particularly noteworthy finding on was that there was more value in interconnection with Victoria. Alongside the need for “*clearly articulated understanding of longer-term objectives, well resourced independent agency with overview role, formal public processes with high transparency*”, this inquiry set the scene for the development of more interconnected grid, and more generally market reform.

During 1990 the Industry Commission began an inquiry into electricity distribution and generation. Specifically, this inquiry was set to investigate the institutional, regulatory or other arrangements subject to influence by governments in Australia, which had lead to inefficient resource use. The Commission recommended significant changes to the structure of the electricity industries, including the separation of ownership of key functions in each industry. A key recommendation included the corporatization of public utilities and the progressive sale of much of the publicly owned generation and distribution assets. Another key recommendation was to increase competition (by disaggregating vertically integrated monopolies).

A.3 1990-1995: Competition Policy, the Hilmer Review and Industry Restructuring

From the early 1990's the Australian governments began to reform the electricity industry. In October 1990, a 'Special Premiers Conference' agreed on a broader framework for improving the Australian Federation, with reform directed at a more efficiency and competitive economy. A subsequent conference established that "*competitive markets would achieve a more efficient allocation of resources within the economy*" and acknowledged "*the role national competition policy could play in underpinning the effective functioning of those markets*". There was a focus on micro-economic and regulatory reform, including in (but not limited to) the areas of electricity generation, transmission and distribution, with the Premiers endorsing the need for a national competition policy.

Following the discussion at these conferences, and in preparation for a full interconnection between the states, the representatives agreed to establish a National Grid Management Council (NGMC). The role of the NGMC was to encourage open access to the grid and free trade in bulk electricity as well as coordinate planning. In addition, the NGMC was to arrange competitive sources of new generation and co-ordinate the most efficient, economic and environmentally sound development of the electricity industry. In 1990, (just prior to the formation of the NGMC) and for the first time in more than 30 years (since the Snowy scheme) the Heywood interconnector between Victoria and South Australia was completed.

In 1992, the Prime Minister announced the establishment of a major independent inquiry into competition policy in Australia (the Hilmer Review). This included the establishment of an independent review of the Trade Practices Act to assess its capacity to secure a national competition policy, and to identify alternative models for regulating market behaviour, as endorsed by the previous Special Premiers' Conferences.

Later in 1992 the then Prime Minister, Premiers and Chief Ministers agreed to establish the Council of Australian Governments (COAG). The Heads of Government endorsed a NGMC National Grid Protocol in this year. This protocol set out the rules, responsibilities and technical requirements for connection to the National Grid and for participating in trading bulk electricity through market sharing. However the NGMC had still not developed the settlement procedures

and accounting procedures for when the grid was fully operational.

In 1993, the Hilmer Review was delivered to COAG with six major policy proposals. These included (but were not limited to) restructuring of public sector monopoly businesses to increase competition, and extending the reach of the trade practices act to increase competition. Subsequently, a National Competition Policy package was agreed to by the heads of government. This included a 'Competition Principles Agreement', in which governments agreed to introduce a fully competitive national market for electricity and restructure their electricity sectors. In 1994 COAG developed a code of conduct for the operation of a national grid consisting of the transmission and distribution systems, and agreed to implement recommendations for a national electricity market consistent with reforms of competition policy and the recommended regulatory arrangements.

During this period, disaggregation, corporatisation and restructuring of the electricity sector across the different jurisdictions had already begun to occur, with corporatisation subjecting government business enterprises to competition law. In 1993-1994 the State Electricity Commission of Victoria was disaggregated and corporatised into three entities, covering mining and generation; transmission and system security; and distribution and retailing. The Electricity Industry Act 1993 (VIC) was the basis for this reform of the Victorian electricity industry. The Office of the Regulator-General Act 1994 (VIC) established the Office of the Regulator-General, to '*promote competitive market conduct*' and prevent '*misuse of market power*' within regulated industries, (such as the electricity industry). The functions of the office were stipulated in the relevant legislation under which the regulated industries operates (in this case the Electricity Industry Act).

The Electricity Trust of South Australia (ETSA) likewise underwent substantial restructuring, including disaggregation in 1993, followed by corporatization on 1 July 1995, under the Electricity Corporations Act 1994 (SA). The Electricity Commission of NSW was restructured into six business units (including generation, pool trading, network and services) in 1992. However it wasn't until 1995 the business units were corporatized, under the Electricity Supply Act 1995 (NSW). The restructuring of Queensland's electricity industry occurred much later than in most other states. The Queensland Electricity Commission was disaggregated into two entities in 1995, which were restructured into corporations in 1997. The Snowy Mountains Hydro-Electric

Authority was also corporatized in 1997 under the Snowy Hydro Corporatisation Act 1997 (C'th).

In this period of transition to a national market, Victoria and New South Wales trialled wholesale electricity markets that used supply and demand principles to set prices. In 1994, the Victorian Whole Electricity Market commenced (VicPool), which was managed by the Victorian Power Exchange (a unit that was split off from the transmission and system security corporation, National Electricity.) Transgrid, a separate statutory authority, under the Electricity Transmission Authority Act 1994 (NSW), was given the authority to operate the NSW electricity market and in 1997, QLD passed an amendment act to provide an interim market in Queensland (which was still electrically separated from NSW).

A.4 1996-2001: The National Electricity Law

In 1996, the state and commonwealth jurisdictions agreed to pass the National Electricity Law (NEL), which provided the legal basis to create the National Electricity Market, and implemented the competitive proposals outlined by Hilmer. The NEL is the lead legislation, giving effect to the National Electricity Market, and is contained in a schedule to the National Electricity Act 1996 (SA). This is applied as law in other states and territories through application Acts and co-operative legislation. The NEL provided the legal basis for the market and for the National Electricity Code (NEC), which contained the market rules, and sets out the objectives of the market, and the rights and responsibilities of market participants. Under the act, the responsibilities of the NGMC were transferred to the National Electricity Market Management Company (NEMMCO), which was established on behalf of the State governments, to manage the wholesale markets on behalf of its participants. The National Electricity Code Administrator (NECA) was also established to enforce and manage the NEC. The NECA and NEMMCO proposed the NEC, which was approved by Australian Competition and Consumer Commission (ACCC), under The Trade Practices Act 1974 (C'wth). The state regulators retained many of the regulatory functions (for the electricity industry) within their jurisdiction. The National Electricity Market commenced operation in December 1998, with Queensland, New South Wales, Victoria, South Australia and the Australian Capital Territory as participating jurisdictions.

At this stage QLD was not physically interconnected with the market. However, construction

of new interconnectors gathered pace with the commencement of the NEM. Two interconnectors between Queensland and New South Wales (Directlink and the Queensland to New South Wales Interconnector) commenced in 2000. This was followed by a second interconnector between Victoria and South Australia (Murraylink) in 2002 .

Tasmania joined the NEM in 2005 and was physically connected with the market in April 2006 with the opening of the Basslink interconnector, a submarine transmission cable from Tasmania to Victoria.

A.5 2002: The Parer Review and the current regulatory framework

In June 2001 the COAG established the Ministerial Council on Energy (MCE) to *‘provide national oversight and coordination of energy policy development and to provide national leadership so that consideration of broader convergence issues and environmental impacts are effectively integrated into energy sector decision-making’* and endorsed the need for a ‘national energy policy framework’. An independent review of market directions was set up to further energy market development (Parer Review), and presented to the MCE in 2002.

The Parer Review acknowledged the progress achieved by the reforms, but highlighted some ‘serious deficiencies’. These deficiencies encompassed unintended consequences of the reform process, and unaddressed reform areas. The review highlighted many issues, including (but not limited to) those relating to governance and regulatory problems. In particular, the review identified that the responsibilities of the key electricity industry governing bodies’ overlap in important areas, and that there were too many regulators. Combined with the differing regulatory bodies across the states, the amount of regulation led to costly inconsistency. It was also found that greenhouse responses to date were ad hoc and poorly targeted. One of the Parer Review recommendations included the creation of a national energy regulator to encompass the energy specific roles of the ACCC, all the state and territory regulatory bodies, and some of the roles of NECA. It also suggested the creation of a statutory end user and industry committee to drive a streamlined process for changes to the National Electricity Code.

The culmination of the review saw the MCE provide a package of recommended reform proposals called ‘Reform of Energy Markets’ to COAG in 2003. This included recommendations for the formation of two new statutory authorities, the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER), and abolishing the NECA. The MCE recommended the AER to be a constituent part of the ACCC but operate as a separate legal entity, and the AEMC to also be a separate legal entity, accountable to and subject to the power of policy direction from the MCE. Other changes were recommended, however no changes were proposed for the structure or function of NEMMCO. The MCE’s recommendations were endorsed by all Parties (States, Territories and Commonwealth of Australia) through the Australian Energy Market Agreement (AEMA) in mid 2004, and the MCE responsibilities were agreed on.

As a result of the AEMA, the Commonwealth amended the Trade Practices Act 1974 (C’t) to establish and enable the conferral of function and powers (in relation to Electricity and Gas) to the AER, as a constituent part of the ACCC. The state of South Australia also submit legislation to establish the AEMC as a South Australian body, through the Australian Energy Market Commission Establishment Act 2004 (SA), with specific provisions in the NEL for judicial review of AEMC decisions. Each of the participating jurisdictions also conferred power functions and power to the AER and the AEMC.

In April 2007 the COAG agreed to establish a single, industry funded, national energy market operator for both electricity and gas to strengthen the national character of energy market governance; the Australian Energy Market Operator (AEMO). Prior to the establishment of AEMO, electricity and gas markets were operated by separate market operators, (for example NEMMCO, and the Gas Retail Market Operator and the Gas Market Company).

Appendix B

NEM and SA - additional analysis

B.1 Load duration curves

Figure B.1 shows the Load Duration Curves (black) and Net Load Duration Curves (blue) for the mainland NEM regions. As is can been seen, the difference between the curves is greatest in South Australia as would be expected for the region with the highest penetration of wind. As there is virtually no non-scheduled or semi-scheduled generation in QLD, the two curves fall on top of each other.

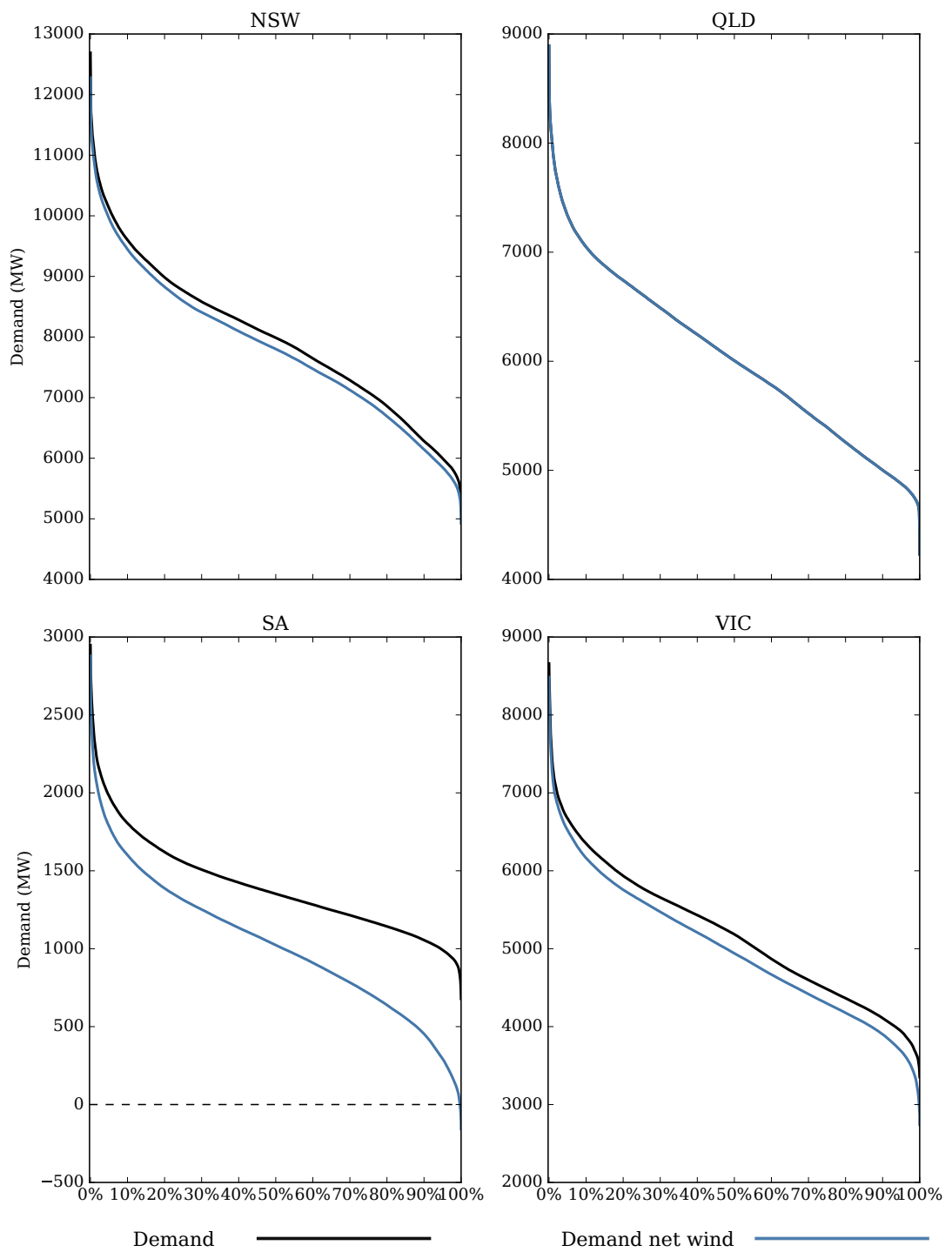


Figure B.1: Load duration curves for the main NEM regions in 2015.

B.2 Power stations by regional basis size, FY16

We define the regional basis size of a power station to be the size of its registered capacity as a percentage of median regional demand. In terms of its regional basis Northern, at 39% was the second largest in the NEM, in FY16 demand terms, behind Loy Yang A in Victoria at 43%. Hazelwood and Yallourn in Victoria are stations commonly discussed as a candidate for closure because of a range of factors including emission intensity, design life and mine stability issues. At 31% and 29% respectively, their regional basis sizes are considerably lower below that of Northern. The regional basis size provides a useful metric for assessing the impact of station closure on market dynamics, though other factors such as ownership distribution amongst remaining plant are clearly important.

Table B.1: Size of NEM coal generators in the relative to median regional demand

State (median demand)	Station Name	Trading rights	Registered Capacity (MW)	Regional basis size
NSW (7966.585)	Eraring	Origin	2880	36.15%
	Bayswater	AGL	2640	33.14%
	Liddell	AGL	2000	25.10%
	Mt Piper	EnergyAustralia	1400	17.57%
	Vales Point B	Sunset Power Int'l	1320	16.57%
QLD (6138.17)	Gladstone	CS Energy	1680	27.37%
	Stanwell	Stanwell Corp.	1460	23.79%
	Tarong	Stanwell Corp.	1400	22.81%
	Millmerran	InterGen	852	13.88%
	Callide	CS Energy / InterGen	840	13.68%
	Kogan Creek	CS Energy	744	12.12%
	Callide B	CS Energy	700	11.40%
Vic (5150.325)	Loy Yang A	AGL	2210	42.91%
	Hazelwood	GDF Suez (Engie)	1600	31.07%
	Yallourn	EnergyAustralia	1480	28.74%
	Loy Yang B	GDF Suez (Engie)	1000	19.42%
SA (1363.215)	Northern		530	38.88%

B.3 Gas generation SA

This table shows gas generation in South Australia for the last calendar year. Using the thermal efficiencies of each plant, the heat rate and approximate gas consumption can be determined¹.

Table B.2: Energy output and gas consumption for gas generators in SA, 2015

Station Name	Output (GWh)	Thermal Efficiency	Heat Rate (MJ/MWh)	Gas (PJ)
Dry Creek Gas	6.34	26%	13846	0.09
Hallett	33	24%	15000	0.49
Ladbroke Grove	206.55	30%	12000	2.48
Mintaro	13.39	28%	12857	0.17
Osborne	1220.82	42%	8571	10.46
Pelican Point	293.55	48%	7500	2.2
Quarantine	137.11	32%	11250	1.54
Torrens Island A	657.6	30%	12000	7.89
Torrens Island B	1967.73	32%	11250	22.14
Total	4536	-	-	47.47

¹Thermal efficiency data from AEMO National Transmission Development Plan (NTNPD) 2015.

B.4 Forecasting

Demand forecasting is an important component of electricity system operation. The Australian Energy Market Operator (AEMO) produces forecasts of demand on various time scales, ranging from five minutes ahead, to years ahead, to facilitate optimal scheduling of resources, and planning for shortfalls or new capacity requirements that may occur in the future.

Similar to demand, the reliability of renewable energy forecasting is an important part of system operation. Forecasting allows capacity requirements to be prepared hours in advance, for times of low renewable dispatch. AEMO's forecasts for wind generation in South Australia are particularly reliable. For example at the half-hour ahead, they are more slightly more accurate than its demand forecasts (see figure B.2). The key point is that while renewable generation varies through time, the variation can be forecast to a standard that does not impose undue risk, at least relative to other forecasts AEMO necessarily undertakes.

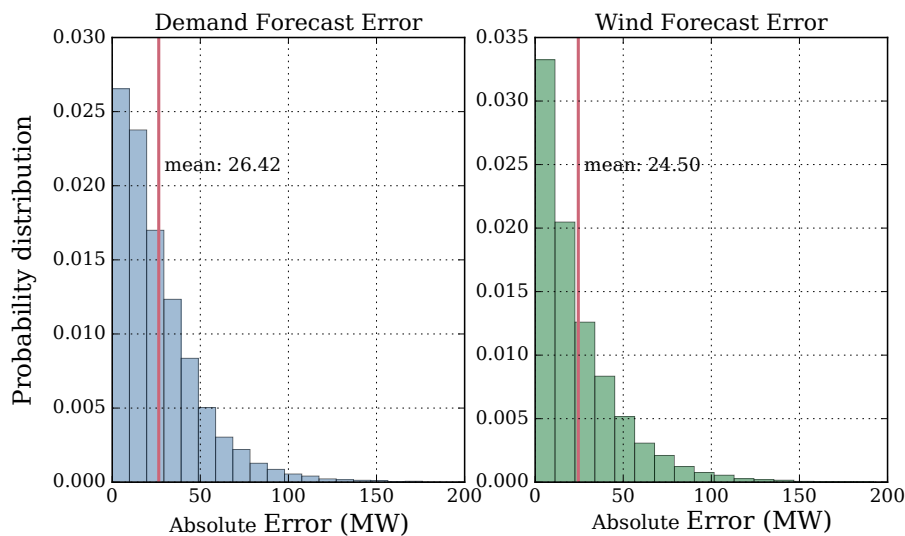


Figure B.2: Normalised density distribution of absolute error, measured in MW, of AEMO forecasts at the half hour interval into the future for calendar year 2015. The South Australian demand forecast error is shown on the left and wind dispatch forecast error is on the right.

B.5 Evolution of Load Duration Curves in South Australia

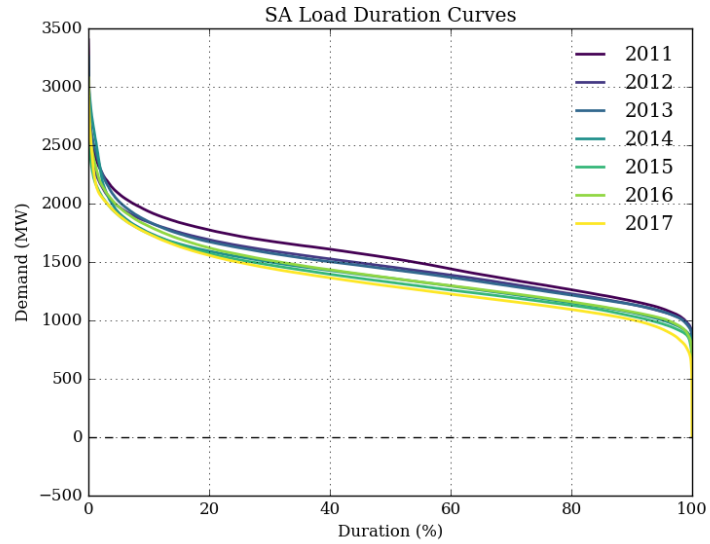


Figure B.3: Load Duration Curves for South Australia over the past seven years

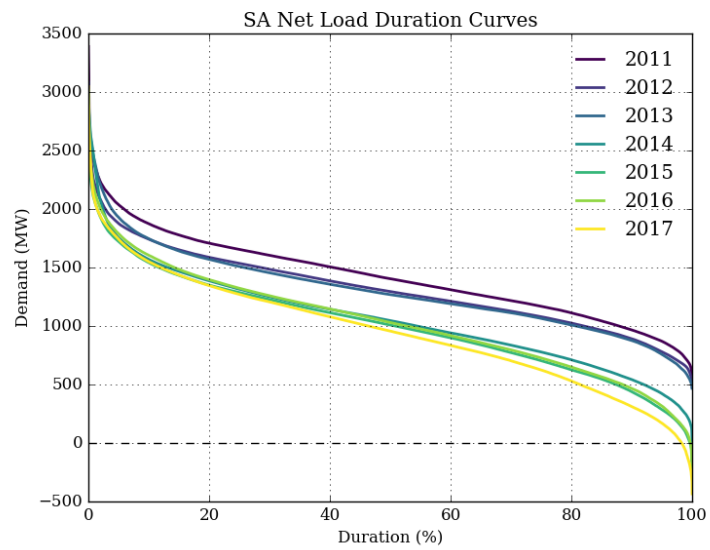


Figure B.4: Net Load Duration Curves for South Australia over the past seven years

B.6 Breakdown of Load Duration Curve in SA

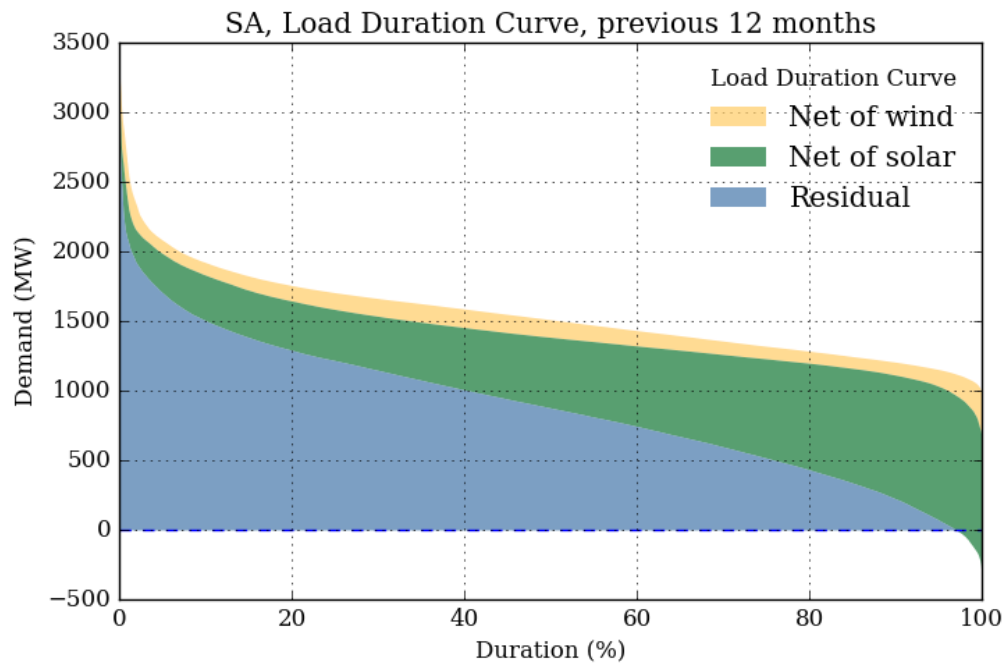


Figure B.5: Net Load Duration Curves for South Australia over year. The area represents the amount of energy provided by the different technologies. As can be seen both solar and wind contribute significant amounts of energy (MWh) to the system but relatively little capacity (MW). The cost of meeting residual peak load must be recovered through a smaller number of MWh's sold.

Appendix C

Levelised cost of capacity assumptions

Levelised Cost of Capacity calculations

A basic¹ levelised cost of energy calculation was modified to determine the *Levelised Cost of Capacity* (LCOC). In this calculation the long-run marginal cost of supplying additional capacity (rather than energy) is determined. Alternatively, the LCOC represents the price (of capacity) required for a project to have a net present value of zero.

The same Weighted Average Cost of Capital (WACC) and economic life were used in all calculations. Technology specific input assumptions and sensitivities can be found below.

1. Global Assumptions

WACC	8%
Economic life	20 years

¹A basic levelised cost of energy (LCOE) calculation does not include financial factors such as depreciation and taxation

2. Open Cycle Gas Turbine

Input data from the Bureau of Resources and Energy Economics (BREE) Australian Energy Technology Assessment². LCOC's with capital cost sensitivities of $\pm 25\%$ were calculated.

Table C.1: OCGT data

CAPEX	\$723/kW
V.O.M	\$10/MWh
F.O.M	\$4/kW-year
Fuel	\$8.57/GJ
Thermal Efficiency	35%
Capacity Factor	10%

3. Pumped Hydro Energy Storage

Input data from the Electric Power Research Institute (EPRI) report *Quantifying the value of hydropower in the electric grid: Plant cost elements*³ was used for the pumped hydro LCOC calculations.

This report contains cost information on a large number of different projects, at different stages of development. For our analysis, we only include recent data (from 2008 onwards) from new projects (expansions of existing facilities are discarded). The costs in this subset varied from as low as \$760/kW (for a 1,470 MW project in Lima, South Africa) to \$2,493 (for a 600 MW project in Kyogoku, Japan), with a mean of \$1,766/kW. This large range reflects the geographically dependant nature of the cost.

The report identified a reasonable relationship between cost per kW per head-height (see figure 4-3 in EPRI, 2011), and suggests '*The expected unit costs for all projects is generally bound by 500 and 2,500 \$/kW, with the majority cluster between 1,000 and 2,000 \$/kW.*' For our analysis we used a base cost of \$1,300/kW (see equation Figure 4-3 in EPRI, 2011) with sensitivities of \$1,000 (-23%) and \$2000/kW (+54%).

The first calculation of the capacity value considered only the cost (per kW) that would

²*Australian Energy Technology Assessment*. Bureau of Resources and Energy Economics, 2012. ISBN 978-1-922106-28-5. URL http://www.bree.gov.au/documents/publications/aeta/Australian_Energy_Technology_Assessment.pdf

³Electric Power Research Institute. *Quantifying the value of hydropower in the electric grid: Plant cost elements*. Technical Report 1023140, November 2011. URL <http://publicdownload.epri.com/PublicDownload.svc/product=000000000001023140>

Table C.2: Pumped hydro data

CAPEX	\$1,300/kW
V.O.M	\$1/MWh
F.O.M	\$7.5/kW-year
Fuel	See note
Thermal Efficiency	–
Capacity Factor	See note

Note: the capacity factor and ‘fuel costs’ (i.e. electricity purchases) are derived from the previous analysis in this paper.

need to be recovered, ignoring any arbitrage revenue (below \$300/MWh). The second calculation (‘PHES ex-arbitrage’) takes into account the below \$300/MWh arbitrage revenue, before determining the required per kW capacity value.

4. Note on Exchange Rates

The BREE report projected the USD/AUD exchange rate to move to a peak of 1.13 by 2016-17⁴ and low of 0.86 by 2031-32. The current exchange rate (May 2015) is approximately 0.79. The exchange rate assumptions are an important input for, and have a significant affect, on the capital cost estimates in the Australian Technology Assessment. As such, the numbers reported in here may not represent current costs.

An exchange rate of 1.035 was used here for conversion of the EPRI capital costs to AUD for comparison purposes. This is the rate assumed to be used by BREE for the 2012 cost.

⁴During 2012, when the report was released, the average USD/AUD exchange rate was 1.035

Appendix D

5 minute settlement

D.1 Sensitivity - battery cost of capacity, 5yr economic life

The results of the a cost of capacity analysis for a lithium-ion battery with economic lifetime of only 5 years (and no replacement cost) is shown here. As in the base case, I considered the additional revenue that is generated for prices below \$300. In addition, I take into account the penalty payments that a cap provider would have to make for occasions where the price is above \$300, but the battery is not discharging, taken from the analysis in section 4.5.3.

Figures D.1 and D.2 illustrate the cap contract required for the battery to financial viable for FY15 and FY16 respectively for a battery with 5 year economic life. As with the base case, the in the less volatile FY15, 30 minute settlement actually *increases* the cost of a cap contract, relative to the perfect ‘capacity only’ case, where the storage perfectly dispatches when the price is above \$300.

In the more volatile FY16, the advantage of 5 minute settlement is also clearly visible in this sensitivity. While the additional revenue from prices below \$300 lowers the cost of cap contract in both cases, the impact is considerable larger under 5-minute settlement. For the low cost estimate, 30-minute settlement increased cap contract prices by 30% relative to the 5-minute settlement case.

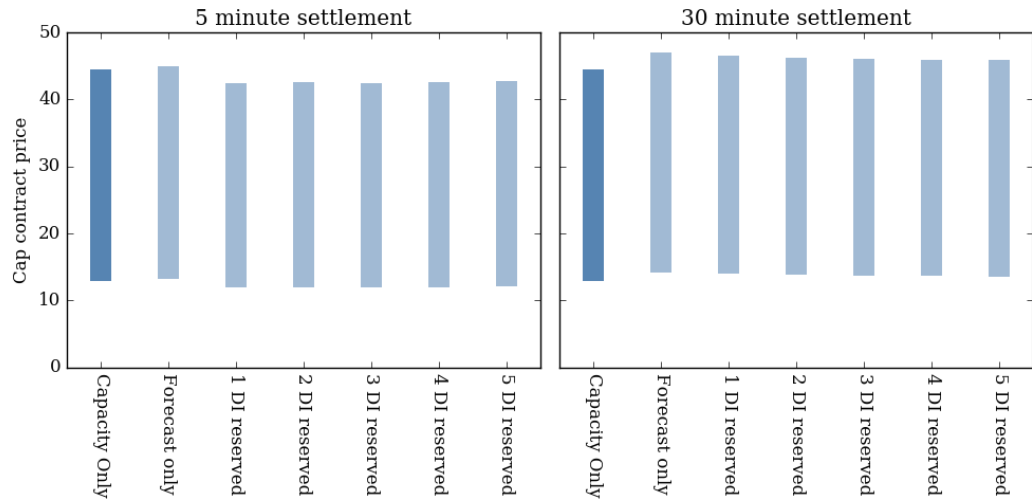


Figure D.1: This figure shows the range of cap prices that a lithium battery would require to be financially viable under different settlement periods and different operating regimes for FY15. The dark bar represents the cap contract price for a perfectly operated battery, that only operates when prices are above \$300. In this scenario, the battery has an economic life of only 5 years.

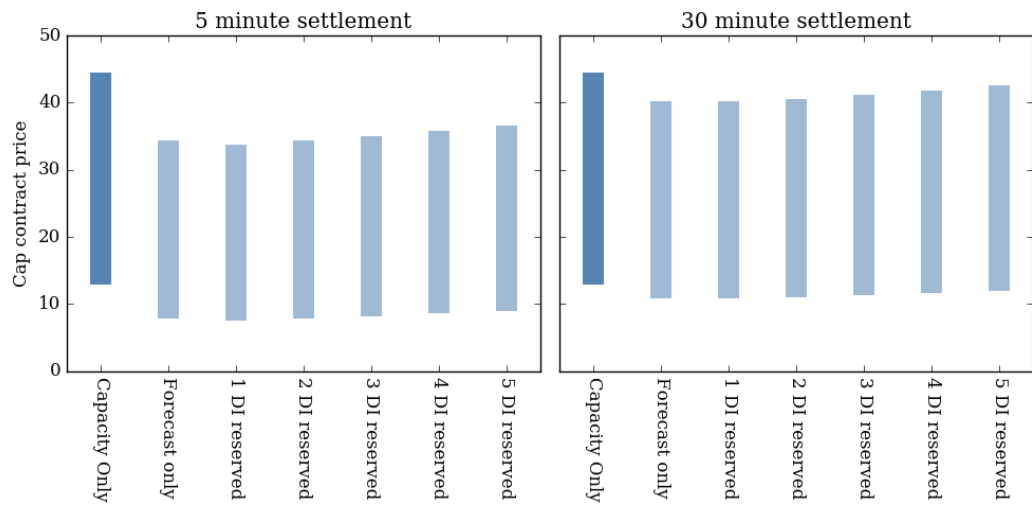


Figure D.2: This figure shows the range of cap prices that a lithium battery would require to be financially viable under different settlement periods and different operating regimes for FY16. The dark bar represents the cap contract price for a perfectly operated battery, that only operates when prices are above \$300. In this scenario, the battery has an economic life of only 5 years.

D.2 QLD price spike analysis

In this analysis, intervals with a price spike at the end of a trading interval in QLD were identified. Price a represents the trading interval price. Price b represents the average price in the first 4 trading intervals. The price difference and demand were used to determine the value of the end of interval price spikes.

Days or trading intervals with several price spikes were filtered out (for example, the 15th of January 2015 and the 5th of March 2015). Such days were assumed to reflect legitimate scarcity. A noteworthy pattern was high prices at 6:55am (trading interval 06), which several times throughout the year (and successive days in July).

Table D.1: Intervals with price spikes in last dispatch interval

Trading Interval	Price a	Price b	Price Diff	Demand	Value (Million)
2015011306	\$4,543	\$65	\$4,478	6267	\$14.03
2015011432	\$2,392	\$238	\$2,153	7700	\$8.29
2015011522	\$2,291	\$140	\$2,151	8458	\$9.10
2015011624	\$2,522	\$33	\$2,489	8434	\$10.50
2015011625	\$2,231	\$34	\$2,197	8423	\$9.25
2015011626	\$4,523	\$35	\$4,488	8462	\$18.99
2015011627	\$2,272	\$24	\$2,248	8356	\$9.39
2015011726	\$2,209	\$64	\$2,145	8320	\$8.92
2015011832	\$2,270	\$115	\$2,155	8296	\$8.94
2015011834	\$2,579	\$578	\$2,001	7908	\$7.91
2015011909	\$2,367	\$167	\$2,201	7682	\$8.45
2015012626	\$2,278	\$32	\$2,246	7884	\$8.85
2015012628	\$2,274	\$29	\$2,245	7864	\$8.83
2015022426	\$2,325	\$105	\$2,221	7585	\$8.42
2015030306	\$2,370	\$105	\$2,265	6415	\$7.27
2015031930	\$2,350	\$219	\$2,131	8485	\$9.04
2015032024	\$2,101	\$443	\$1,658	8470	\$7.02
2015071306	\$2,325	\$58	\$2,267	6832	\$7.75
2015071606	\$2,400	\$67	\$2,333	6954	\$8.11
2015071706	\$2,351	\$50	\$2,301	7000	\$8.05
2015071837	\$2,459	\$194	\$2,265	6542	\$7.41
2015072006	\$2,336	\$40	\$2,296	6564	\$7.53
2015072906	\$2,352	\$52	\$2,300	6668	\$7.67
2015080530	\$4,847	\$371	\$4,476	7412	\$16.59
2015082006	\$2,334	\$36	\$2,297	6551	\$7.53
2015111925	\$2,334	\$255	\$2,079	7682	\$7.98
2015112023	\$2,433	\$252	\$2,181	7361	\$8.03
			Total		\$250

Appendix E

Co-optimisation problem description

E.1 Full model description

The optimisation problem is formulated as follows:

Maximise:

$$\sum_{i=1}^n P_{e_i} \cdot (Q_{c_i} - Q_{d_i}) + P_{rr_i} \cdot Q_{rr_i} + P_{lr_i} \cdot Q_{lr_i} + P_{rc_i} \cdot Q_{rc_i} + P_{lc_i} \cdot Q_{lc_i} \quad (\text{E.1})$$

Subject to:

$$0 \leq Q_{d_i} + Q_{rr_i} + Q_{rc_i} \leq Q_{d_{max}} \quad (\text{E.2})$$

$$0 \leq Q_{c_i} + Q_{lr_i} + Q_{lc_i} \leq Q_{c_{max}} \quad (\text{E.3})$$

$$0 \leq E_i \leq E_{max} \quad (\text{E.4})$$

$$E_{i-1} + \eta_c Q_{c_i} - \eta_d Q_{c_i} = E_i \quad (\text{E.5})$$

Where:

Q_{c_i} = charge rate at interval i

Q_{d_i} = discharge rate for interval i

Q_{rr_i} = capacity enabled for raise regulation for interval i

Q_{rc_i} = capacity enabled for lower regulation for interval i

Q_{lr_i} = capacity enabled for raise contingency for interval i

Q_{lc_i} = capacity enabled for lower contingency for interval i

P_{e_i} = energy price at interval i

P_{rr_i} = raise regulation price at interval i

P_{lr_i} = lower regulation price at interval i

P_{rc_i} = raise contingency price at interval i

P_{lc_i} = lower contingency price at interval i

E_i = total energy stored at interval i

E_{max} = maximum energy storage

$Q_{c_{max}}$ = maximum charge rate

$Q_{d_{max}}$ = maximum discharge rate

η_c = charging efficiency

η_d = discharging efficiency

n = number of intervals optimised

Appendix F

The openNEM project

The OpenNEM project aims to make the wealth of public National Electricity Market (NEM) data more accessible to a wider audience. This leverages the that database and data management system described in Appendix C.

F.1 Website

The openNEM website is the public facing component of the broader openNEM platform, which can be found at opennem.org.au. The default landing page of the website shows the previous week of generation data for a week in the National Electricity Market (NEM), and is illustrated below in figure F.1. A summary of the data is displayed in a table at the right hand side.

Key navigation tools can be found on the top left and top right of the screen and are shown below in figure F.2. On the upper left hand side, the data can be explore by region (by selecting different regions of the NEM). On the upper left hand side, different time ranges and resolutions can be selected and explored. The selected data can then be downloaded via the export button (discussed further in later sections).

Figure F.3 below show the previous week of generation for South Australia. The regional data views also include wholesale spot price and temperature data as well. Figure F.4 below show the previous year of generation for Victoria. In this case, the data is presented as *energy* data (in GWh) rather than power data (MW) in the default week long view. This also includes

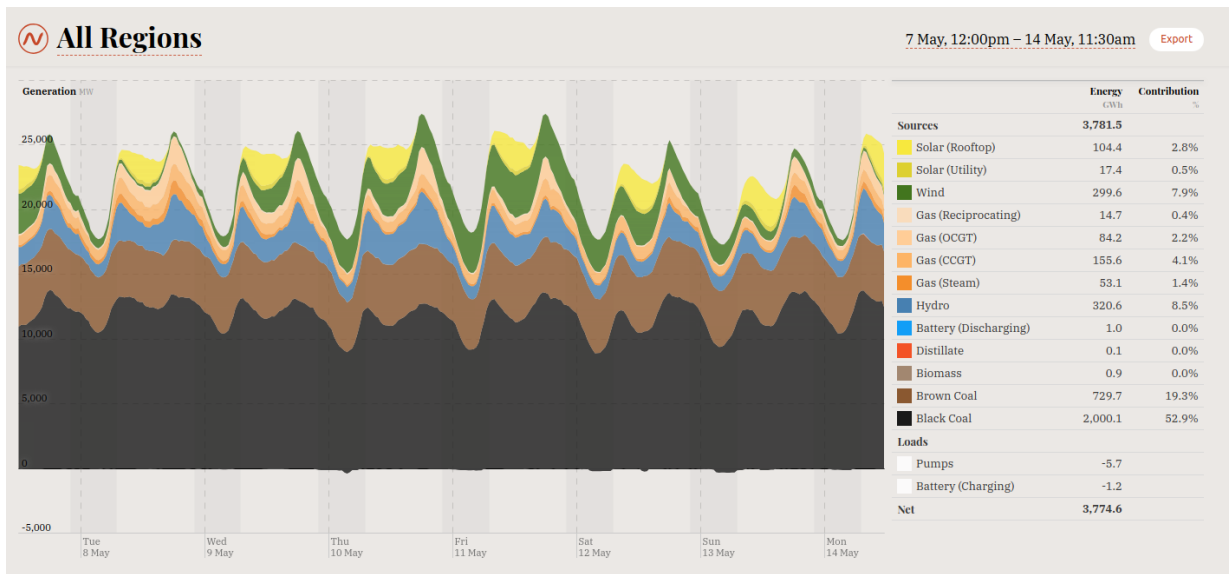


Figure F.1: Screen shot of the default landing page website showing previous week of generation data for South Australia. This data displays *power* data at a 30 minute time resolution

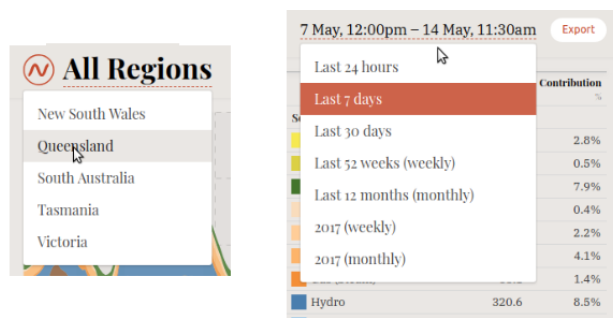


Figure F.2: Basic website navigation options

a summary of the aggregated data on the right hand side.

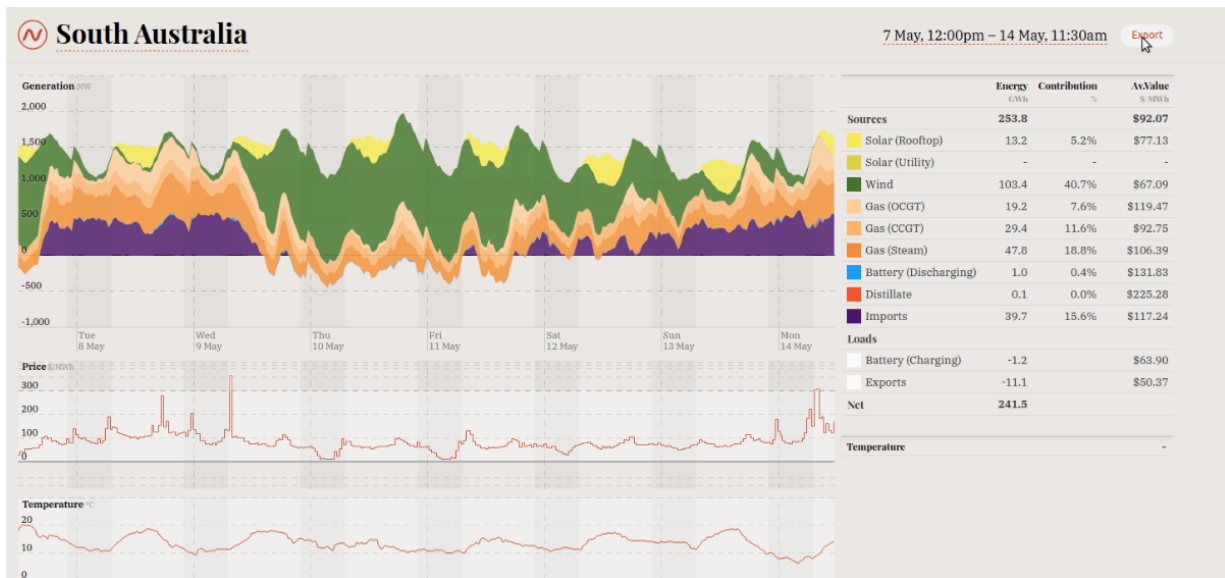


Figure F.3: Screen shot of the website showing previous week of generation data for South Australia. This data is displayed as energy data at a 30 minute time resolution

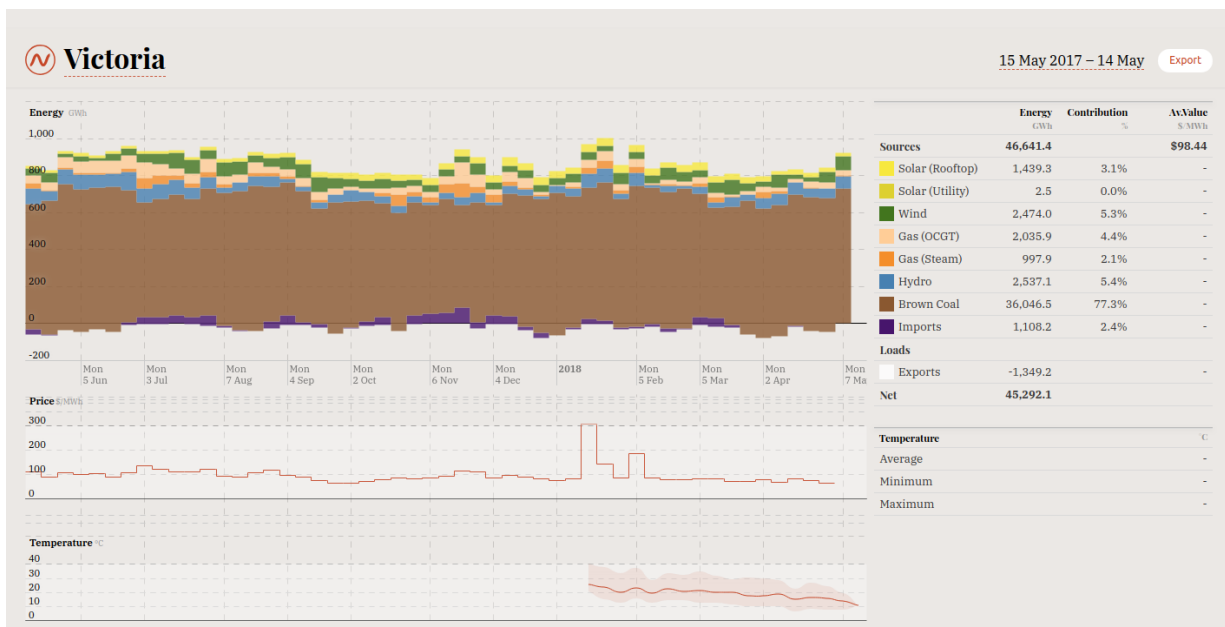


Figure F.4: Screen shot of the website showing previous year of generation data for Victoria. This data is displayed as energy data at a weekly time resolution

F.2 Basic: data access through the website

Importantly, the underlying data is available for direct download from every page, and every different page view. The date range and region of data selected dictates which data is available for download. Once a desired selection have been made, the data can be downloaded as a csv file by clicking the export button on the top right hand corner of the page, and selecting “Export as Spreadsheet (CSV)” (see figure F.5). Exporting as Image (PNG) is discussed further in section 4.

This will download a csv file of the data selection on to your local computer. This file can be opened with range of different programs, including excel and other spreadsheet software, as well as other applications (including R and python). Figure F.6 below shows how the csv looks when opened in spreadsheet software.

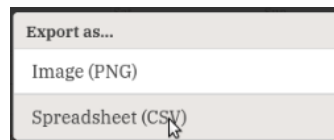


Figure F.5: Export options

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Time	Volume Weighted Price - \$/MWh	Trading Price - \$/MWh	Temperature - C	Solar (Rooftop) - MW	Solar (Utility) - MW	Wind - MW	Gas (Reciprocating) - MW	Gas (OCGT) - MW	Gas (CCGT) - MW	Gas (Steam) - MW	Hydro - MW	Battery (Discharging) - MW	Distillate - MW	Biomass - MW
2	2018-05-07 12:00	0	29.25	17.9	169.24	0	1215.48	0	0	155.44	182.16	0	0	0.02	0
3	2018-05-07 12:05	0	29.25		169.24	0	1222.71	0	0	155.66	188.21	0	0	0.02	0
4	2018-05-07 12:10	0	29.25		169.24	0	1215.65	0	0	154.98	175.71	0	0	0.02	0
5	2018-05-07 12:15	0	29.25		169.24	0	1225.61	0	0	155.76	166.81	0	0	0.02	0
6	2018-05-07 12:20	0	29.25		169.24	0	1216.63	0	0	155.89	162.48	0	0	0.02	0
7	2018-05-07 12:25	0	29.25		169.24	0	1222.64	0	0	156.44	162.88	0	0	0.02	0
8	2018-05-07 12:30	0	42.7	19.3	175.91	0	1218.45	0	0	155.87	161.51	0	0	0.02	0
9	2018-05-07 12:35	0	42.7		175.91	0	1217.78	0	0	155.78	164.5	0	0	0.02	0
10	2018-05-07 12:40	0	42.7		175.91	0	1223.99	0	0	151.39	156.31	0	0	0.02	0
11	2018-05-07 12:45	0	42.7		175.91	0	1219.15	0	0	153.13	168.18	0	0	0.02	0
12	2018-05-07 12:50	0	42.7		175.91	0	1222.2	0	0	151.87	180.23	0	0	0.02	0
13	2018-05-07 12:55	0	42.7		175.91	0	1207.22	0	0	152.48	171.94	0	0	0.02	0
14	2018-05-07 13:00	0	36.36	20.1	242.06	0	1224.66	0	0	153.28	153.74	0	0	0.02	0
15	2018-05-07 13:05	0	36.36		242.06	0	1210.93	0	0	152.92	160.99	0	0	0.02	0
16	2018-05-07 13:10	0	36.36		242.06	0	1225.34	0	0	153.1	188.65	0	0	0.02	0
17	2018-05-07 13:15	0	36.36		242.06	0	1222.65	0	0	154.98	181.62	0	0	0.02	0
18	2018-05-07 13:20	0	36.36		242.06	0	1227.49	0	0	154.56	171.19	0	0	0.02	0
19	2018-05-07 13:25	0	36.36		242.06	0	1217.41	0	0	156.25	170.12	0	0	0.02	0
20	2018-05-07 13:30	0	53.61	19.8	256.04	0	1220.3	0	0	155.18	178.72	0	0	0.02	0
21	2018-05-07 13:35	0	53.61		256.04	0	1227.85	0	0	155.48	171.89	0	0	0.02	0
22	2018-05-07 13:40	0	53.61		256.04	0	1206.38	0	0	155.03	171.53	0	0	0.02	0
23	2018-05-07 13:45	0	53.61		256.04	0	1223.36	0	0	156.15	172.43	0	0	0.02	0
24	2018-05-07 13:50	0	53.61		256.04	0	1212.22	0	0	156.44	174.47	0	5.1	0.02	0
25	2018-05-07 13:55	0	53.61		256.04	0	1213.23	0	0	155.45	154.42	0	0	0.02	0
26	2018-05-07 14:00	0	51.91	19.7	201.42	0	1199.4	0	0	156.84	156.68	0	0	0.02	0
27	2018-05-07 14:05	0	51.91		201.42	0	1220.47	0	0	155.63	163.92	0	8.3	0.02	0
28	2018-05-07 14:10	0	51.91		201.42	0	1195.53	0	0	154.05	170.82	0	0	0.02	0
29	2018-05-07 14:15	0	51.91		201.42	0	1207.98	0	0	155.69	169.25	0	0	0.02	0
30	2018-05-07 14:20	0	51.91		201.42	0	1184.04	0	0	155.07	178.59	0	2.9	0.02	0
31	2018-05-07 14:25	0	51.91		201.42	0	1202.28	0	0	155.51	187.13	0	6	0.02	0
32	2018-05-07 14:30	0	54.51	19.8	164.31	0	1206.24	0	0	156.28	185.55	0	0	0.02	0
33	2018-05-07 14:35	0	54.51		164.31	0	1192.48	0	0	155.48	186.12	0	4.9	0.02	0
34	2018-05-07 14:40	0	54.51		164.31	0	1182.29	0	0	156.71	181.47	0	0	0.02	0
35	2018-05-07 14:45	0	54.51		164.31	0	1208.92	0	0	156.44	183.4	0	0	0.02	0
36	2018-05-07 14:50	0	54.51		164.31	0	1214.68	0	0	155.03	179.25	0	0	0.02	0
37	2018-05-07 14:55	0	54.51		164.31	0	1211.53	0	0	156.61	178.13	0	0	0.02	0
38	2018-05-07 15:00	0	58.87	19.3	98.95	0	1205.52	0	0	155.22	185.92	0	0	0.02	0
39	2018-05-07 15:05	0	58.87		98.95	0	1199.62	0	0	154.98	182.87	0	0	0.02	0
40	2018-05-07 15:10	0	58.87		98.95	0	1188.8	0	0	156	196.18	0	8	0.02	0
41	2018-05-07 15:15	0	58.87		98.95	0	1191.13	0	0	155.58	184.03	0	0	0.02	0
42	2018-05-07 15:20	0	58.87		98.95	0	1193.99	0	0	156.05	178.68	0	0	0.02	0
43	2018-05-07 15:25	0	58.87		98.95	0	1195.64	0	0	156.13	187.25	0	0	0.02	0
44	2018-05-07 15:30	0	56.49	18.1	52.28	0	1188.5	0	0	156.76	187.54	0	0	0.02	0
45	2018-05-07 15:35	0	56.49		52.28	0	1220.32	0	0	142.01	198.03	0	0	0.02	0
46	2018-05-07 15:40	0	56.49		52.28	0	1221.09	0	0	140.08	212.13	0	0	0.02	0
47	2018-05-07 15:45	0	56.49		52.28	0	1211.88	0	0	140.36	240.67	0	7.4	0.02	0
48	2018-05-07 15:50	0	56.49		52.28	0	1222.61	0	0	163.67	199.79	0	1	0.02	0

Figure F.6: Example of csv file downloaded from openNEM website

F.3 Advanced: Application Programming Interface (API)

The data that underpins the openNEM website is hosted on a separate dedicated server (data.opennem.org.au). This is the openNEM Application Programming Interface (API): it is the part of the platform that receives requests (for data) and sends responses (containing data). The openNEM website, (and the direct download capability from the website) interfaces with this API and uses the same data¹.

There is a python repository that allows direct access the data this data server, and the data the underpins the openNEM. This module allows programmatic python based access to the data available on API. This github repository can be found here: opennempy²

Documentation on using this module can be found on the git repository, as well as an example ipython notebook, (example.ipynb). A simple example is shown below and over page. There is

¹Indeed anyone could do this, and inteface their own website with the API

²<https://github.com/dylanjmconnell/opennempy>

additional documentation on a separate ‘github pages’ site [opennempy](https://dylanjmccconnell.github.io/opennempy/)³

```
In [1]: from opennempy import web_api

In [2]: #load data for a particular time period and NEM region (in this case SA)
df_5, df_30 = web_api.load_data(d1=datetime.datetime(2018,3,4), d2 = datetime.datetime(2018,4,19), region='sa1')

In [3]: #remove empty cols
df_5.dropna(axis=1, inplace=True)

In [4]: df_30.head()
```

	PRICE	TEMPERATURE	ROOFTOP_SOLAR
2018-03-04 00:30:00	62.22	17.9	0.0
2018-03-04 01:00:00	59.65	17.5	0.0
2018-03-04 01:30:00	60.60	18.0	0.0
2018-03-04 02:00:00	59.21	18.1	0.0
2018-03-04 02:30:00	56.07	18.2	0.0

```

In [5]: df_5.head()
Out[5]:
```

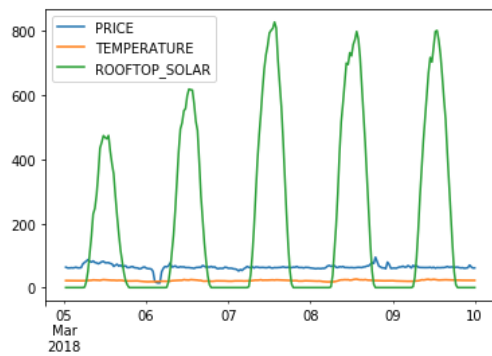
	DEMAND	NETINTERCHANGE	BATTERY	DISTILLATE	GAS_CCGT	GAS_OCGT	GAS_STEAM	WIND
2018-03-04 00:05:00	1442.02	-2.51	20.2	-0.06	473.70	0.0	149.60	801.91
2018-03-04 00:10:00	1436.01	14.83	23.9	-0.03	476.57	0.0	121.26	812.66
2018-03-04 00:15:00	1395.63	43.27	-6.1	-0.03	475.98	0.0	116.70	790.71
2018-03-04 00:20:00	1373.62	56.93	-38.9	-0.03	466.62	0.0	122.47	791.69
2018-03-04 00:25:00	1411.29	19.12	15.3	-0.03	474.80	0.0	121.41	789.92

Figure F.7: Example of ipython notebook running opennempy

³<https://dylanjmccconnell.github.io/opennempy/>

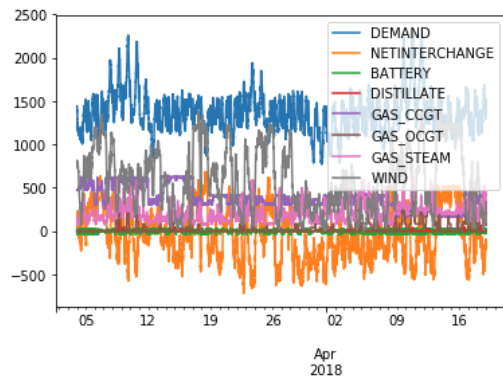
```
In [7]: nsw_30.plot()
```

```
Out[7]: <matplotlib.axes._subplots.AxesSubplot at 0x7f7915f30240>
```



```
In [8]: df_5.plot()
```

```
Out[8]: <matplotlib.axes._subplots.AxesSubplot at 0x7f7915f09b00>
```



```
In [9]: df_5.mean()
```

```
Out[9]: DEMAND      1353.735515
NETINTERCHANGE    -49.873793
BATTERY           -0.978465
DISTILLATE         0.343244
GAS_CCGT          391.934075
GAS_OCGT          48.902212
GAS_STEAM         215.159675
WIND              592.422441
dtype: float64
```

Figure F.8: Example of ipython notebook running opennempy

F.4 Source Code

The code used to create and maintain this project is broken into three major git repositories⁴. These repositories are all hosted on ‘GitHub’, an online platform commonly used to host open-source software projects.

The three different repositories reflect the three different functions of the associated code: the website, the data management back end, and direct access to the data server API.

- **opennem-fe**: This is the code base for the front end (fe) of the openNEM website. This code is predominantly written in javascript, and can be found in an public available github repository here: [opennem-fe](#)⁵
- **opennem**: This is the main code base for downloading and managing the data from the Australian Energy Market Operator’s (AEMO’s) online data portal, ‘nemweb’⁶. This is primarily written in ‘python’ and interfaces with a mysql server. This github repository can be found here: [opennem](#)⁷
- **opennempy**: This is a python repository to directly access the data that underpins the openNEM platform. This module allows programatic python based access to the data available on API, hosted on [data.opennem.org.au](#). This github repository can be found here: [opennempy](#)⁸

⁴Git is a version control system primarily used for tracking changes in source code, and source code management in software development.

⁵<https://github.com/chienleng/opennem-fe>

⁶<http://www.nemweb.com.au/>

⁷<https://github.com/dylanjmccconnell/opennem>

⁸<https://github.com/dylanjmccconnell/opennempy>

F.5 Data sets

The raw datasets utilised on `opennem.org.au` and hosted on the data server (`data.opennem.org.au`) are listed in G. Broadly speaking, the data can be broken into two distinct categories; trading data, available at a 30 minute resolution, and dispatch data, available at a 5 minute resolution. These data sets mirror the datasets and structures in AEMO’s ‘Market Management System’ (MMS)⁹.

A more detailed description of the fields in each table can be found in the following section. As above, the tables names and fields follow the same conventions as used by AEMO.

Table F.1: Datasets hosted on the openNEM platform

Dispatch (5min)	Trading (30min)
DISPATCH.REGIONSUM	TRADING.REGIONSUM
DISPATCH.PRICE	TRADING.PRICE
DISPATCH.INTERCONNECTORRES	TRADING.INTERCONNECTORRES
DISPATCH.UNIT.SCADA	
DISPATCH.UNIT.SOLUTION	ROOFTOP.ACTUAL
	ROOFTOP.FORECAST

In addition to these raw datasets, aggregated (derived) data sets can be found on `data.opennem.org.au`. This includes summary of of generation or price over time (e.g. weekly, or annually) and aggregation over different different technologies (in the case of generation). This aggregated data can also be downloaded with the `opennempy` python application.

In addition to the AEMO data, we have also included data (specifically temperature data) from the Bureau of Meterology (BoM).

⁹For more information see the MMS website here: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS>

Appendix G

Datasets

DISPATCH_UNIT_SOLUTION

Set out the current SCADA MW and target MW for each dispatchable unit, including relevant Frequency Control Ancillary Services (FCAS) enabling targets for each five minutes and additional fields to handle the new Ancillary Services functionality. Fast Start Plant status is indicated by dispatch mode.

Name	Description	Format
SETTLEMENTDATE	Market date and time starting at 04:05	datetime
DUID	Dispatchable unit identifier	smallint(6)
INTERVENTION	Intervention flag if intervention run	tinyint(4)
DISPATCHMODE	Dispatch mode for fast start plant (0 to 4).	tinyint(4)
AGCSTATUS	AGC Status from EMS* 1 = on* 0 = off	tinyint(4)
INITIALMW	Initial MW at start of period	decimal(10,6)
TOTALCLEARED	Target MW for end of period	decimal(10,6)

continued ...

Name	Description	Format
RAMPDOWNRATE	Ramp down rate used in dispatch (lesser of bid or telemetered rate).	decimal(8,2)
RAMPUPRATE	Ramp up rate (lesser of bid or telemetered rate).	decimal(8,2)
LOWER5MIN	Lower 5 min reserve target	decimal(10,6)
LOWER60SEC	Lower 60 sec reserve target	decimal(10,6)
LOWER6SEC	Lower 6 sec reserve target	decimal(10,6)
RAISE5MIN	Raise 5 min reserve target	decimal(10,6)
RAISE60SEC	Raise 60 sec reserve target	decimal(10,6)
RAISE6SEC	Raise 6 sec reserve target	decimal(10,6)
LOWERREG	Lower Regulation reserve target	decimal(10,6)
RAISEREG	Raise Regulation reserve target	decimal(10,6)
AVAILABILITY	Bid energy availability	decimal(10,6)

DISPATCH_REGIONSUM

Sets out the 5-minute solution for each dispatch run for each region, including the Frequency Control Ancillary Services (FCAS) services provided. Additional fields are for the Raise Regulation and Lower Regulation Ancillary Services plus improvements to demand calculations.

Name	Description	Format
SETTLEMENTDATE	Market date and time starting at 04:05	datetime
REGIONID	Region Identifier	tinyint(4)
TOTALDEMAND	Demand (less loads)	decimal(7,2)
AVAILABLEGENERATION	Aggregate generation bid available in region	decimal(10,5)
AVAILABLELOAD	Aggregate load bid available in region	decimal(7,2)
DEMANDFORECAST	5 minute forecast adjust	decimal(10,5)
DISPATCHABLEGENERATION	Dispatched Generation	decimal(7,2)
DISPATCHABLELOAD	Dispatched Load (add to total demand to get inherent region demand).	decimal(7,2)
NETINTERCHANGE	Net interconnector flow from the regional reference node	decimal(6,2)
EXCESSGENERATION	MW quantity of excess	decimal(7,2)
INITIALSUPPLY	Sum of initial generation and import for region	decimal(10,5)
CLEAREDSUPPLY	Sum of cleared generation and import for region	decimal(7,2)

continued ...

Name	Description	Format
TOTALINTERMITTENTGENERATION	Allowance made for non-scheduled generation in the demand forecast (MW).	decimal(10,5)
DEMAND_AND_NONSCHEDGEN	Sum of Cleared Scheduled generation, imported generation (at the region boundary) and allowances made for non-scheduled generation (MW).	decimal(10,5)
UIGF	Regional aggregated Unconstrained Intermittent Generation Forecast of Semi-scheduled generation (MW).	decimal(10,5)
SEMISCHEDULE_CLEAREDMW	Regional aggregated Semi-Schedule generator Cleared MW	decimal(10,5)
DISPATCHINTERVAL	Dispatch period identifier, from 001 to 288 in format YYYYMMDDPPP.	bigint(20)
SEMISCHEDULE_COMPLIANCEMW	Regional aggregated Semi-Schedule generator Cleared MW where Semi-Dispatch cap is enforced	decimal(10,5)
INTERVENTION	Manual Intervention flag	tinyint(4)
LOWERREGLOCALDISPATCH	Lower Regulation local dispatch	decimal(10,5)
LOWER5MINLOCALDISPATCH	Lower 5 min local dispatch	decimal(10,5)
LOWER60SECLOCALDISPATCH	Lower 60 sec local dispatch	decimal(10,5)
LOWER6SECLOCALDISPATCH	Lower 6 sec local dispatch	decimal(10,5)
RAISE5MINLOCALDISPATCH	Raise 5 min local dispatch	decimal(10,5)

continued ...

Name	Description	Format
RAISEREGLOCALDISPATCH	Raise Regulation local dispatch	decimal(10,5)
RAISE60SECLOCALDISPATCH	Raise 60 sec local dispatch	decimal(10,5)
RAISE6SECLOCALDISPATCH	Raise 6 sec local dispatch	decimal(10,5)
AGGREGATEDISPATCHERROR	Calculated dispatch error	decimal(10,5)
RAISE6SECACTUALAVAILABILITY	trapezium adjusted raise 6sec availability	decimal(12,6)
RAISE5MINACTUALAVAILABILITY	trapezium adjusted raise 5min availability	decimal(12,6)
RAISE60SECACTUALAVAILABILITY	trapezium adjusted raise 60sec availability	decimal(12,6)
RAISEREGACTUALAVAILABILITY	trapezium adjusted raise reg availability	decimal(12,6)
LOWER6SECACTUALAVAILABILITY	trapezium adjusted lower 6sec availability	decimal(12,6)
LOWER5MINACTUALAVAILABILITY	trapezium adjusted lower 5min availability	decimal(12,6)
LOWER60SECACTUALAVAILABILITY	trapezium adjusted lower 60sec availability	decimal(12,6)
LOWERREGACTUALAVAILABILITY	trapezium adjusted lower reg availability	decimal(12,6)

DISPATCH.INTERCONNECTORRES

Sets out MW flow and losses on each interconnector for each dispatch period, including fields for the Frequency Controlled Ancillary Services export and import limits and extra reporting of the generic constraints set the energy import and export limits.

Name	Description	Format
SETTLEMENTDATE	Market date starting at 04:05	datetime

continued ...

Name	Description	Format
INTERCONNECTORID	Interconnector identifier	tinyint(4)
METEREDMWFLOW	Metered MW Flow from SCADA.	decimal(10,5)
MWLOSSES	Calculated MW Losses	decimal(8,5)
EXPORTLIMIT	Calculated export limit applying to energy only.	decimal(10,5)
IMPORTLIMIT	Calculated import limit applying to energy only.	decimal(10,5)
MARGINALLOSS	Marginal loss factor. Use this to adjust prices between regions.	decimal(6,5)
DISPATCHINTERVAL	Dispatch period identifier, from 001 to 288 in format YYYYMMDDPPP.	bigint(20)
MWFLOW	Target MW Flow for next 5 mins.	decimal(10,5)
INTERVENTION	Intervention case or not	tinyint(4)

DISPATCH_PRICE

Records 5 minute dispatch prices for energy and FCAS, including whether an intervention has occurred, or price override (e.g. for Administered Price Cap). DISPATCHPRICE updates when price adjustments occur, in which case the new price is written to the RRP field, and the old price to the ROP field as an audit trail.

Name	Description	Format
REGIONID	Region Identifier	tinyint(4)

continued ...

Name	Description	Format
SETTLEMENTDATE	Market date and time starting at 04:05	datetime
DISPATCHINTERVAL	Dispatch interval identifier 001 to 288 in format YYYYMMDDPPP	bigint(20)
RRP	Regional Reference Price for this dispatch period. RRP is the price used to settle the market	decimal(10,5)
ROP	Regional Override Price, being the original price prior to any price scaling, price capping or VoLL override being applied. The APC flag allows the determination of whether capping, scaling or override occurred	decimal(12,5)
APCFLAG	APC Active flag (see note)	tinyint(4)
CUMUL_PRE_AP_ENERGY_PRICE	Cumulative price that triggers administered pricing event if above the threshold	decimal(16,10)
INTERVENTION	Manual intervention flag	tinyint(4)
RAISE6SECRRP	Regional reference price (Raise 6sec) for this dispatch period	decimal(12,5)
RAISE6SECROP	Original regional price (Raise 6sec) prior to APC or VoLL overrides applied	decimal(12,5)
RAISE6SECAPCFLAG	Flag indicating if the apevent covers a Raise 6sec AP	tinyint(4)

continued ...

Name	Description	Format
RAISE60SECRRP	Regional reference price (Raise 60sec) for this dispatch period	decimal(12,5)
RAISE60SECROP	Original regional price (Raise 60sec) prior to APC or VoLL overrides applied	decimal(12,5)
RAISE60SECAPCFLAG	Flag indicating if the apevent covers a Raise 60sec AP	tinyint(4)
RAISE5MINRRP	Regional reference price (Raise 5min) for this dispatch period	decimal(12,5)
RAISE5MINROP	Original regional price (Raise 5min) prior to APC or VoLL overrides applied	decimal(12,5)
RAISE5MINAPCFLAG	Flag indicating if the apevent covers a Raise 5min AP	tinyint(4)
RAISEREGRRP	Regional reference price (Raise Reg) for this dispatch period	decimal(12,5)
RAISEREGROP	Original regional price (Raise Reg) prior to APC or VoLL overrides applied	decimal(12,5)
RAISEREGAPCFLAG	Flag indicating if the apevent covers a Raise Reg AP	tinyint(4)
LOWER6SECRRP	Regional reference price (Lower 6sec) for this dispatch period	decimal(12,5)
LOWER6SECROP	Original regional price (Lower 6sec) prior to APC or VoLL overrides applied	decimal(12,5)

continued ...

Name	Description	Format
LOWER6SECAPCFLAG	Flag indicating if the apevent covers a Lower 6sec AP	tinyint(4)
LOWER60SECRRP	Regional reference price (Lower 60sec) for this dispatch period	decimal(12,5)
LOWER60SECROP	Original regional price (Lower 60sec) prior to APC or VoLL overrides applied	decimal(12,5)
LOWER60SECAPCFLAG	Flag indicating if the apevent covers a Lower 60sec AP	tinyint(4)
LOWER5MINRRP	Regional reference price (Lower 5min) for this dispatch period	decimal(12,5)
LOWER5MINROP	Original regional price (Lower 5min) prior to APC or VoLL overrides applied	decimal(12,5)
LOWER5MINAPCFLAG	Flag indicating if the apevent covers a Lower 5min AP	tinyint(4)
LOWERREGRRP	Regional reference price (Lower Reg) for this dispatch period	decimal(12,5)
LOWERREGROP	Original regional price (Lower Reg) prior to APC or VoLL overrides applied	decimal(12,5)
LOWERREGAPCFLAG	Flag indicating if the apevent covers a Lower Reg AP	tinyint(4)

TRADING_REGIONSUM

Sets out the half-hourly average regional demand and frequency control services. TRADINGREGIONSUM includes fields for the Raise Regulation and Lower Regulation Ancillary Services plus improvements to demand calculations.

Name	Description	Format
SETTLEMENTDATE	Date that this data applies to	datetime
REGIONID	Region Identifier	tinyint(4)
TOTALDEMAND	Total demand for region	decimal(7,2)
AVAILABLEGENERATION	The available generation in the Region for the interval	decimal(7,2)
AVAILABLELOAD	Not used	decimal(7,2)
DEMANDFORECAST	Forecast demand for region	decimal(7,2)
DISPATCHABLEGENERATION	Averaged generation dispatched in region	decimal(7,2)
DISPATCHABLELOAD	Averaged load dispatched in region	decimal(7,2)
NETINTERCHANGE	Average energy transferred over interconnector	decimal(7,2)
EXCESSGENERATION	Average excess generation in region	decimal(7,2)
INITIALSUPPLY	Sum of initial generation and import for region	decimal(7,2)
CLEAREDSUPPLY	Sum of cleared generation and import for region	decimal(7,2)

continued ...

Name	Description	Format
TOTALINTERMITTENTGENERATION	Allowance made for non-scheduled generation in the demand forecast (MW).	decimal(7,2)
DEMAND_AND_NONSCHEDGEN	Sum of Cleared Scheduled generation, imported generation (at the region boundary) and allowances made for non-scheduled generation (MW).	decimal(7,2)
UIGF	Regional aggregated Unconstrained Intermittent Generation Forecast of Semi-scheduled generation (MW).	decimal(7,2)
LOWERREGLOCALDISPATCH	Lower Regulation local dispatch	decimal(10,5)
LOWER5MINLOCALDISPATCH	Lower 5 min local dispatch	decimal(10,5)
LOWER60SECLOCALDISPATCH	Lower 60 sec local dispatch	decimal(10,5)
LOWER6SECLOCALDISPATCH	Lower 6 sec local dispatch	decimal(10,5)
RAISE5MINLOCALDISPATCH	Raise 5 min local dispatch	decimal(10,5)
RAISEREGLOCALDISPATCH	Raise Regulation local dispatch	decimal(10,5)
RAISE60SECLOCALDISPATCH	Raise 60 sec local dispatch	decimal(10,5)
RAISE6SECLOCALDISPATCH	Raise 6 sec local dispatch	decimal(10,5)

TRADING_PRICE

Sets out half-hourly spot market price, including fields to handle the Ancillary Services functionality. If prices are adjusted, the final price is recorded in the regional reference price (RRP) field with price before adjustment recorded in the regional original price (ROP) field.

Name	Description	Format
SETTLEMENTDATE	Date that this data applies to	datetime
REGIONID	Region Identifier	tinyint(4)
RRP	Regional reference price for this dispatch period	decimal(7,2)
ROP	Regional Original Price. The price before any adjustments were made	decimal(8,2)
RAISE6SECRRP	Regional reference price for this dispatch period	decimal(12,5)
RAISE6SECROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)
RAISE60SECRRP	Regional reference price for this dispatch period	decimal(12,5)
RAISE60SECROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)
RAISE5MINRRP	Regional reference price for this dispatch period	decimal(12,5)
RAISE5MINROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)
RAISEREGRRP	Regional reference price for this dispatch period	decimal(12,5)
RAISEREGROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)

continued ...

Name	Description	Format
LOWER6SECRRP	Regional reference price for this dispatch period	decimal(12,5)
LOWER6SECROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)
LOWER60SECRRP	Regional reference price for this dispatch period	decimal(12,5)
LOWER60SECROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)
LOWER5MINRRP	Regional reference price for this dispatch period	decimal(12,5)
LOWER5MINROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)
LOWERREGRRP	Regional reference price for this dispatch period	decimal(12,5)
LOWERREGROP	Original regional price - prior to APC or VoLL overrides applied	decimal(12,5)

TRADING INTERCONNECTORRES

Shows the half-hourly summary of Interconnector flows based on 5-minute averages.

Name	Description	Format
SETTLEMENTDATE	Date that this data applies to	datetime
INTERCONNECTORID	Interconnector identifier	tinyint(4)

continued ...

Name	Description	Format
METEREDMWFLOW	Average of the metered MW flow from the start of each dispatch interval.	decimal(6,2)
MWFLOW	Calculated MW Flow from SPD	decimal(6,2)
MWLOSSES	MW losses at calculated MW flow	decimal(6,2)

ROOFTOP_ACTUAL

Estimate of regional Rooftop Solar actual generation for each half-hour interval in a day

Name	Description	Format
INTERVAL_DATETIME	The forecast half-hour interval (time ending)	datetime
REGIONID	Region identifier	tinyint(4)
POWER	Estimated generation in MW at the interval end	decimal(8,3)

METER_DATA_GEN_DUID

Recorded actual generation of non-scheduled units where SCADA data is available.

Name	Description	Format
INTERVAL_DATETIME	Timestamp of the recorded interval	datetime
DUID	Dispatch Unit ID	smallint(6)
MWH_READING	MW reading	decimal(10,6)

OFFER_BIDDAYOFFER

Shows the Energy and Ancillary Service bid data for each Market Day. BIDDAYOFFER is the parent table to BIDPEROFFER.

Name	Description	Format
DUID	Dispatchable unit identifier	smallint(6)
SETTLEMENTDATE	Market date for applying the bid	datetime
OFFERDATE	Offer date of data	datetime
VERSIONNO	Version No. for given offer date	smallint(6)
BIDTYPE	Bid Type Identifier	tinyint(4)
DAILYENERGYCONSTRAINT	Maximum energy available from Energy Constrained Plant. (Energy Bids Only)	int(11)
PRICEBAND1	Price for Availability Band 1	decimal(7,2)
PRICEBAND2	Price for Availability Band 2	decimal(7,2)
PRICEBAND3	Price for Availability Band 3	decimal(7,2)
PRICEBAND4	Price for Availability Band 4	decimal(7,2)
PRICEBAND5	Price for Availability Band 5	decimal(7,2)
PRICEBAND6	Price for Availability Band 6	decimal(7,2)
PRICEBAND7	Price for Availability Band 6	decimal(7,2)
PRICEBAND8	Price for Availability Band 8	decimal(7,2)
PRICEBAND9	Price for Availability Band 9	decimal(7,2)

continued ...

Name	Description	Format
PRICEBAND10	Price for Availability Band 10	decimal(7,2)
MINIMUMLOAD	Minimum MW load fast start plant	mediumint(9)
LASTCHANGED	Last date and time record changed	datetime
ENTRYTYPE	Daily if processed before BidCutOff of previous day, otherwise REBID	char(5)
T1	Time to synchronise in minutes (Energy Bids Only)	tinyint(4)
T2	Time to minimum load in minutes (Energy Bids Only)	tinyint(4)
T3	Time at minimum load in minutes (Energy Bids Only)	tinyint(4)
T4	Time to shutdown in minutes (Energy Bids Only)	tinyint(4)

OFFER_BIDPEROFFER

Shows period-based Energy and Ancillary Service bid data. BIDPEROFFER is a child table of BIDDAYOFFER.

Name	Description	Format
DUID	Dispatchable Unit identifier	smallint(6)
SETTLEMENTDATE	Market date starting at 04:05	datetime
OFFERDATE	Offer date	datetime

continued ...

Name	Description	Format
PERIODID	Period ID	tinyint(4)
VERSIONNO	Version number of offer	mediumint(9)
BIDTYPE	Bid Type Identifier	tinyint(4)
MAXAVAIL	Maximum availability for this BidType in this period	mediumint(9)
ROCUP	MW/min for raise (Energy Bids Only)	smallint(6)
ROCDOWN	MW/Min for lower (Energy Bids Only)	smallint(6)
BANDAVAIL1	Availability at price band 1	smallint(6)
BANDAVAIL2	Availability at price band 2	smallint(6)
BANDAVAIL3	Availability at price band 3	smallint(6)
BANDAVAIL4	Availability at price band 4	smallint(6)
BANDAVAIL5	Availability at price band 5	smallint(6)
BANDAVAIL6	Availability at price band 6	smallint(6)
BANDAVAIL7	Availability at price band 7	smallint(6)
BANDAVAIL8	Availability at price band 8	smallint(6)
BANDAVAIL9	Availability at price band 9	smallint(6)
BANDAVAIL10	Availability at price band 10	smallint(6)
LASTCHANGED	Last date and time record changed	datetime